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June 11, 2019

via RESS

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

Dear Ms. Walli:

Re: EB File No. EB-2018-0165, Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Responses to Evidence Update Interrogatories and Corrections

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Further to Procedural Order No. 4, enclosed with this letter is an electronic version of Toronto Hydro's responses to interrogatories posed with respect to the Application Update. Physical copies will follow via courier. In advance of the Oral Hearing, Toronto Hydro will file electronic copies of consolidated versions of the Application and Evidence and Interrogatory Responses.

On May 21, 2019, Toronto Hydro received interrogatories from:

- OEB Staff ("Staff"),
- Association of Major Power Consumers in Ontario ("AMPCO"),
- Building Owners and Managers Association ("BOMA"),
- Consumers Council of Canada ("CCC"),
- Energy Probe Research Foundation ("EP"),
- School Energy Coalition ("SEC"), and
- Vulnerable Energy Consumers Coalition ("VECC").

Certain interrogatories requested excel or other data files. Where applicable, Toronto Hydro has provided these files with the filenames indicating the interrogatory to which they correspond.

In preparing the Interrogatory Responses, Toronto Hydro identified errors in two documents filed as part of the Application Update dated April 30, 2019, namely Appendices B and C of Exhibit U, Tab 3, Schedule 1. Toronto Hydro has provided the corrected versions as attachments to the interrogatories

U-VECC-78 and U-VECC-79, and will also file the corrected versions with the consolidated Application and Evidence and Interrogatory Responses.

Please contact me directly if you have any questions or concerns.

Respectfully,

Andrew J. Sasso
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited

cc: Lawrie Gluck, OEB Case Manager
Michael Millar, OEB Counsel
Parties of Record
Amanda Klein, Toronto Hydro
Daliana Coban, Toronto Hydro
Charles Keizer, Torys LLP

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TORONTO HYDRO

June 12, 2019

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

Dear Ms. Walli:

Re: EB-2018-0165, Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Responses to Evidence Update Interrogatories and Correction

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On June 11, 2019, Toronto Hydro submitted its responses to interrogatories posed with respect to the Application Update. In a subsequent review, Toronto Hydro determined that it needs to amend its response to the interrogatory, U-AMPCO-124. The revised response attaching the 2017 and 2018 Canadian Electricity Association ("CEA") Reports is appended to this cover letter. Please note that the latter (2018 CEA Report) was issued yesterday, subsequent to the finalization of the filing.

Pursuant to Rule 10.01 of the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Confidential Filings* (the "**Practice Direction**"), Toronto Hydro hereby requests the confidential treatment of the 2017 and 2018 CEA Reports. In EB-2014-0116, the Ontario Energy Board (the "OEB") considered the confidentiality of other CEA reports. The OEB determined that the disclosure of those reports would prejudice CEA's competitive position and would produce a significant economic loss to the CEA. The OEB concluded that if the reports were publicly available, the CEA would lose the ability to sell it for financial gain. In striving to find a balance between the general public interest in transparency and openness, and the need to protect the CEA's competitive position, the OEB was satisfied that confidential treatment of the CEA reports was warranted.[1] While the CEA reports from EB-2014-0116 were benchmarking reports, whereas the 2017 and 2018 CEA Reports being filed at this time are general industry information reports, Toronto Hydro submits that for the purposes of a confidentiality determination, the reports are sufficiently similar to receive the same treatment.

Please note that the 2017 and 2018 CEA Reports are being provided to the OEB in a separate, sealed envelope that is marked "Confidential" and have been excluded from the electronic version of this request.

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[1] EB-2014-0116, OEB Decision and Order on Notice of Motion, February 11, 2015, pp. 10-11.

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

Yours truly,

Andrew J. Sasso
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June 14, 2019

via RESS

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

Dear Ms. Walli:

Re: EB File No. EB-2018-0165, Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate-setting ("Custom IR") Application for 2020-2024 Electricity Distribution Rates and Charges – Interrogatory Responses Record Update

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On June 11, 2019, Toronto Hydro filed interrogatory responses pursuant to the OEB's Procedural Order No. 4. On June 12, 2019, the utility filed an update to one of those responses, U-AMPCO-124.

Due to inadvertent administrative processing issues, two other responses must be addressed: U-Staff-193, which was previously omitted; and U-Staff-168, which incorrectly listed certain dates.

Filed concurrently with this letter is a revised version of the Application Update interrogatory responses. Toronto Hydro requests that the OEB replace the previously filed Application Update interrogatory responses with this one.

Please contact me directly if you have any questions or concerns.

Respectfully,

Andrew J. Sasso
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited

cc: Lawrie Gluck, OEB Case Manager
Michael Millar, OEB Counsel
Parties of Record
Amanda Klein, Toronto Hydro
Daliana Coban, Toronto Hydro
Charles Keizer, Torys LLP

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166:

Reference(s): Multiple Interrogatory and Undertaking Responses

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   i) 1C-Staff-48 / parts (f), (g)
   ii) 2A-Staff-59 / part (c)
   iii) 2B-Staff-75 / parts (b), (c), (d)
   iv) 2B-Staff-76 / part (c)
   v) 2B-Staff-78 / parts (a), (b – add 2018 to Tables 3 and 4 and show the revised capital contribution percentage calculated using the 2014-2018 data and both Toronto Hydro's proposed weighted average methodology and a simple average methodology)
   vi) 2B-Staff-81 / part (c – add 2018 to Table 1 and provide 2015-2018 average)
   vii) 2B-Staff-84 / parts (a), (b – update 2018 in Table 2 and provide updated unit costs for 2019-2024 based on the 2015-2018 data and Toronto Hydro's proposed weighted average methodology)
   viii) 2B-Staff-91 / parts (b), (c)
   ix) 3-Staff-107 / part (b)
   x) 4A-Staff-112
   xi) 4A-Staff-128 / part (b)
   xii) 4A-Staff-131 / part (b)
   xiii) 4A-Staff-138 / part (b)
   xiv) 9-Staff-154 / part (b-iv)

b) Please update the following undertaking responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:
   i) JTC1.10
   ii) JTC1.15
   iii) JTC 4.3

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

a) Please see attached responses labeled U-Staff-166.1 to U-Staff-166.14.

b) Please see attached responses labeled U-Staff-166.15 to U-Staff-166.17.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.1:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   i) 1C-Staff-48 / parts (f), (g)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

The update to Toronto Hydro's response to interrogatory 1C-Staff-48 (f) is set out in Table 1 below.

Table 1: 2015-2018 Dividends, Net Income, and Total Debt ($ Millions)

	2015	2016	2017	2018
Dividends paid	0	0	2.1	42.7
Net income	132.8	148.5	138.6	163.1
Total debt	2,132.5	2,220.8	2,246.6	2,148.2

The update to Toronto Hydro's response to interrogatory 1C-Staff-48 (g) is set out in Table 2.

Table 2: THESL Net Income ($ Millions)

	2015	2016	2017	2018
THESL net income (A)	132.8	148.5	138.6	163.1
Consolidated net income (B)	126.7	151.4	156.5	167.3
% (A/B)	104.8%	98.1%	88.6%	97.5%

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.2:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   ii) 2A-Staff-59 / part (c)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated Appendices in Appendix A and B to this response.

Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Generation, Protection, Monitoring and Control

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2020 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2015 Total	2015 Direct Benefit 6%	2015 Provincial 94%	2016 Total	2016 Direct Benefit 6%	2016 Provincial 94%	2017 Total	2017 Direct Benefit 6%	2017 Provincial 94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,045,544	$ 62,733	$ 982,811
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recc		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ 62,733	$ 982,811
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ 2,509	$ 39,312
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ 35,130	$ 550,374
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ 25,093	$ 393,124
ST Interest	2.61%		$ -	$ -		$ -	$ -		$ 65	$ 1,026
LT Interest	3.71%		$ -	$ -		$ -	$ -		$ 1,303	$ 20,419
ROE	8.82%		$ -	$ -		$ -	$ -		$ 2,213	$ 34,674
Cost of Capital Total			$ -	$ -		$ -	$ -		$ 3,582	$ 56,119
OM&A			$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ 38,724	$ 2,323	$ 36,400
Grossed-up PILs			$ -	$ -		$ -	$ -		-$ 207	-$ 3,247
Revenue Requirement			$ -	$ -		$ -	$ -		$ 5,698	$ 89,272
Provincial Rate Protection				$ -			$ -			$ 89,272
Monthly Amount Paid by IESO				$ -			$ -			$ 7,439

		2018 Total	2018 Direct Benefit 6%	2018 Provincial 94%	2019 Total	2019 Direct Benefit 6%	2019 Provincial 94%	2020 Total	2020 Direct Benefit 6%	2020 Provincial 94%
Net Fixed Assets (average)		$ 2,052,364	$ 123,142	$ 1,929,222	$ 3,918,071	$ 235,084	$ 3,682,987	$ 7,525,106	$ 451,506	$ 7,073,599
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recc		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 123,142	$ 1,929,222		$ 235,084	$ 3,682,987		$ 451,506	$ 7,073,599
Deemed ST Debt	4%		$ 4,926	$ 77,169		$ 9,403	$ 147,319		$ 18,060	$ 282,944
Deemed LT Debt	56%		$ 68,959	$ 1,080,364		$ 131,647	$ 2,062,473		$ 252,844	$ 3,961,216
Deemed Equity	40%		$ 49,257	$ 771,689		$ 94,034	$ 1,473,195		$ 180,603	$ 2,829,440
ST Interest	2.61%		$ 129	$ 2,014		$ 245	$ 3,845		$ 471	$ 7,385
LT Interest	3.71%		$ 2,558	$ 40,082		$ 4,884	$ 76,518		$ 9,380	$ 146,961
ROE	8.82%		$ 4,344	$ 68,063		$ 8,294	$ 129,936		$ 15,929	$ 249,557
Cost of Capital Total			$ 7,031	$ 110,159		$ 13,423	$ 210,299		$ 25,781	$ 403,903
OM&A			$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 77,448	$ 4,647	$ 72,801	$ 149,416	$ 8,965	$ 140,451	$ 288,544	$ 17,313	$ 271,232
Grossed-up PILs			-$ 297	-$ 4,648		-$ 458	-$ 7,174		-$ 782	-$ 12,255
Revenue Requirement			$ 11,382	$ 178,311		$ 21,930	$ 343,575		$ 42,311	$ 662,879
Provincial Rate Protection				$ 178,311			$ 343,575			$ 662,879
Monthly Amount Paid by IESO				$ 14,859			$ 28,631			$ 55,240

		2021 Total	2021 Direct Benefit 6%	2021 Provincial 94%	2022 Total	2022 Direct Benefit 6%	2022 Provincial 94%
Net Fixed Assets (average)		$ 10,157,593	$ 609,456	$ 9,548,138	$ 12,033,772	$ 722,026	$ 11,311,745
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recc		$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -
Rate Base			$ 609,456	$ 9,548,138		$ 722,026	$ 11,311,745
Deemed ST Debt	4%		$ 24,378	$ 381,926		$ 28,881	$ 452,470
Deemed LT Debt	56%		$ 341,295	$ 5,346,957		$ 404,335	$ 6,334,577
Deemed Equity	40%		$ 243,782	$ 3,819,255		$ 288,811	$ 4,524,698
ST Interest	2.61%		$ 636	$ 9,968		$ 754	$ 11,809
LT Interest	3.71%		$ 12,662	$ 198,372		$ 15,001	$ 235,013
ROE	8.82%		$ 21,502	$ 336,858		$ 25,473	$ 399,078
Cost of Capital Total			$ 34,800	$ 545,199		$ 41,228	$ 645,901
OM&A			$ -	$ -		$ -	$ -
Amortization		$ 396,731	$ 23,804	$ 372,927	$ 480,912	$ 28,855	$ 452,058
Grossed-up PILs			-$ 560	-$ 8,776		$ 38	$ 595
Revenue Requirement			$ 58,044	$ 909,349		$ 70,120	$ 1,098,554
Provincial Rate Protection				$ 909,349			$ 1,098,554
Monthly Amount Paid by IESO				$ 75,779			$ 91,546

		2023 Total	2023 Direct Benefit 6%	2023 Provincial 94%	2024 Total	2024 Direct Benefit 6%	2024 Provincial 94%
Net Fixed Assets (average)		$ 13,959,787	$ 837,587	$ 13,122,199	$ 15,946,138	$ 956,768	$ 14,989,370
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recc		$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -
Rate Base			$ 837,587	$ 13,122,199		$ 956,768	$ 14,989,370
Deemed ST Debt	4%		$ 33,503	$ 524,888		$ 38,271	$ 599,575
Deemed LT Debt	56%		$ 469,049	$ 7,348,432		$ 535,790	$ 8,394,047
Deemed Equity	40%		$ 335,035	$ 5,248,880		$ 382,707	$ 5,995,748
ST Interest	2.61%		$ 874	$ 13,700		$ 999	$ 15,649
LT Interest	3.71%		$ 17,402	$ 272,627		$ 19,878	$ 311,419
ROE	8.82%		$ 29,550	$ 462,951		$ 33,755	$ 528,825
Cost of Capital Total			$ 47,826	$ 749,278		$ 54,631	$ 855,893
OM&A			$ -	$ -		$ -	$ -
Amortization		$ 570,058	$ 34,203	$ 535,854	$ 664,740	$ 39,884	$ 624,855
Grossed-up PILs			$ 758	$ 11,872		$ 1,594	$ 24,975
Revenue Requirement			$ 82,787	$ 1,297,004		$ 96,110	$ 1,505,723
Provincial Rate Protection				$ 1,297,004			$ 1,505,723
Monthly Amount Paid by IESO				$ 108,084			$ 125,477

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2015 Direct Benefit	2015 Provincial	2016 Direct Benefit	2016 Provincial	2017 Direct Benefit	2017 Provincial	2018 Direct Benefit	2018 Provincial	2019 Direct Benefit	2019 Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ 2,213	$ 34,674	$ 4,344	$ 68,063	$ 8,294	$ 129,936
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ 2,323	$ 36,400	$ 4,647	$ 72,801	$ 8,965	$ 140,451
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	-$ 5,112	-$ 80,081	-$ 9,814	-$ 153,755	-$ 18,529	-$ 290,286
Taxable income	$ -	$ -	$ -	$ -	-$ 575	-$ 9,007	-$ 823	-$ 12,892	-$ 1,270	-$ 19,899
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	$ -	$ -	$ -	$ -	-$ 152.35	-$ 2,386.83	-$ 218.06	-$ 3,416.27	-$ 336.59	-$ 5,273.24
Gross Up										
Income Taxes Payable	$ -	$ -	$ -	$ -	$ (207.28)	$ (3,247.39)	$ (296.68)	$ (4,647.98)	$ (457.95)	$ (7,174.48)
Grossed Up PILs	$ -	$ -	$ -	$ -	-$ 207	-$ 3,247	-$ 297	-$ 4,648	-$ 458	-$ 7,174

Income Tax	2020 Direct Benefit	2020 Provincial	2021 Direct Benefit	2021 Provincial	2022 Direct Benefit	2022 Provincial	2023 Direct Benefit	2023 Provincial	2024 Direct Benefit	2024 Provincial
Net Income - ROE on Rate Base	$ 15,929	$ 249,557	$ 21,502	$ 336,858	$ 25,473	$ 399,078	$ 29,550	$ 462,951	$ 33,755	$ 528,825
Amortization (6% DB and 94% P)	$ 17,313	$ 271,232	$ 23,804	$ 372,927	$ 28,855	$ 452,058	$ 34,203	$ 535,854	$ 39,884	$ 624,855
CCA (6% DB and 94% P)	-$ 35,411	-$ 554,780	-$ 46,859	-$ 734,127	-$ 54,222	-$ 849,485	-$ 61,652	-$ 965,879	-$ 69,218	-$ 1,084,410
Taxable income	-$ 2,170	-$ 33,991	-$ 1,554	-$ 24,342	$ 105	$ 1,652	$ 2,102	$ 32,927	$ 4,421	$ 69,270
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	-$ 574.96	-$ 9,007.74	-$ 411.74	-$ 6,450.53	$ 27.94	$ 437.65	$ 556.96	$ 8,725.66	$ 1,171.69	$ 18,356.54
Gross Up										
Income Taxes Payable	$ (782.26)	$ (12,255.43)	$ (560.18)	$ (8,776.23)	$ 38.01	$ 595.44	$ 757.76	$ 11,871.64	$ 1,594.14	$ 24,974.89
Grossed Up PILs	-$ 782	-$ 12,255	-$ 560	-$ 8,776	$ 38	$ 595	$ 758	$ 11,872	$ 1,594	$ 24,975

Net Fixed Assets

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Enter applicable amortization in years:	27.5										
Opening Gross Fixed Assets		-	$ -	$ -	$ 2,129,811	$ 2,129,811	$ 6,088,091	$ 9,781,841	$ 12,038,341	$ 14,411,841	$ 16,941,341
Gross Capital Additions		$ -	$ -	$ 2,129,811	$ -	$ 3,958,279	$ 3,693,750	$ 2,256,500	$ 2,373,500	$ 2,529,500	$ 2,678,000
Closing Gross Fixed Assets		$ -	$ -	$ 2,129,811	$ 2,129,811	$ 6,088,091	$ 9,781,841	$ 12,038,341	$ 14,411,841	$ 16,941,341	$ 19,619,341
Opening Accumulated Amortization		$ -	$ -	$ -	$ 38,724	$ 116,172	$ 265,588	$ 554,132	$ 950,863	$ 1,431,775	$ 2,001,833
Current Year Amortization (before additions)		$ -	$ -	$ -	$ 77,448	$ 77,448	$ 221,385	$ 355,703	$ 437,758	$ 524,067	$ 616,049
Additions (half-year)		$ -	$ -	$ 38,724	$ -	$ 71,969	$ 67,159.09	$ 41,027	$ 43,155	$ 45,991	$ 48,691
Closing Accumulated Amortization		$ -	$ -	$ 38,724	$ 116,172	$ 265,588	$ 554,132	$ 950,863	$ 1,431,775	$ 2,001,833	$ 2,666,573
Opening Net Fixed Assets		$ -	$ -	$ -	$ 2,091,087	$ 2,013,640	$ 5,822,503	$ 9,227,709	$ 11,087,478	$ 12,980,066	$ 14,939,508
Closing Net Fixed Assets		$ -	$ -	$ 2,091,087	$ 2,013,640	$ 5,822,503	$ 9,227,709	$ 11,087,478	$ 12,980,066	$ 14,939,508	$ 16,952,768
Average Net Fixed Assets		$ -	$ -	$ 1,045,544	$ 2,052,364	$ 3,918,071	$ 7,525,106	$ 10,157,593	$ 12,033,772	$ 13,959,787	$ 15,946,138

UCC for PILs Calculation

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening UCC		$ -	$ -	$ -	$ 2,044,619	$ 1,881,049	$ 5,530,514	$ 8,634,072	$ 10,109,587	$ 11,579,380	$ 13,081,349
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ 2,129,811	$ -	$ 3,958,279	$ 3,693,750	$ 2,256,500	$ 2,373,500	$ 2,529,500	$ 2,678,000
UCC Before Half Year Rule		$ -	$ -	$ 2,129,811	$ 2,044,619	$ 5,839,329	$ 9,224,264	$ 10,890,572	$ 12,483,087	$ 14,108,880	$ 15,759,349
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ 1,064,906	$ -	$ 1,979,140	$ 1,846,875	$ 1,128,250	$ 1,186,750	$ 1,264,750	$ 1,339,000
Reduced UCC		$ -	$ -	$ 1,064,906	$ 2,044,619	$ 3,860,189	$ 7,377,389	$ 9,762,322	$ 11,296,337	$ 12,844,130	$ 14,420,349
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ 85,192	$ 163,570	$ 308,815	$ 590,191	$ 780,986	$ 903,707	$ 1,027,530	$ 1,153,628
Closing UCC		$ -	$ -	$ 2,044,619	$ 1,881,049	$ 5,530,514	$ 8,634,072	$ 10,109,587	$ 11,579,380	$ 13,081,349	$ 14,605,721

Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments
Energy Storage

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2020 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2015			2016			2017			2018		
		Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)		$ -	$ -	$ -	$-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Pro		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable fo		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	6.4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	2.61%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	3.71%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE	8.82%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -

	2019			2020			2021			2022			2023			2024		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)	$ 1,533,705	$ 92,022	$ 1,441,682	$ 3,444,970	$ 206,698	$ 3,238,272	$ 4,166,758	$ 250,005	$ 3,916,752	$ 4,821,879	$ 289,313	$ 4,532,566	$ 5,410,333	$ 324,620	$ 5,085,713	$ 5,932,121	$ 355,927	$ 5,576,194
Incremental OM&A (on-going, N/A for Pro	$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable fo	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ 92,022	$ 1,441,682		$ 206,698	$ 3,238,272		$ 250,005	$ 3,916,752		$ 289,313	$ 4,532,566		$ 324,620	$ 5,085,713		$ 355,927	$ 5,576,194
Deemed ST Debt		$ 3,681	$ 57,667		$ 8,268	$ 129,531		$ 10,000	$ 156,670		$ 11,573	$ 181,303		$ 12,985	$ 203,429		$ 14,237	$ 223,048
Deemed LT Debt		$ 51,532	$ 807,342		$ 115,751	$ 1,813,432		$ 140,003	$ 2,193,381		$ 162,015	$ 2,538,237		$ 181,787	$ 2,848,000		$ 199,319	$ 3,122,669
Deemed Equity		$ 36,809	$ 576,673		$ 82,679	$ 1,295,309		$ 100,002	$ 1,566,701		$ 115,725	$ 1,813,026		$ 129,848	$ 2,034,285		$ 142,371	$ 2,230,478
ST Interest		$ 96	$ 1,505		$ 216	$ 3,381		$ 261	$ 4,089		$ 302	$ 4,732		$ 339	$ 5,309		$ 372	$ 5,822
LT Interest		$ 1,912	$ 29,952		$ 4,294	$ 67,278		$ 5,194	$ 81,374		$ 6,011	$ 94,169		$ 6,744	$ 105,661		$ 7,395	$ 115,851
ROE		$ 3,247	$ 50,863		$ 7,292	$ 114,246		$ 8,820	$ 138,183		$ 10,207	$ 159,909		$ 11,453	$ 179,424		$ 12,557	$ 196,728
Cost of Capital Total		$ 5,254	$ 82,320		$ 11,802	$ 184,905		$ 14,275	$ 223,647		$ 16,520	$ 258,810		$ 18,536	$ 290,394		$ 20,323	$ 318,401
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ 105,773	$ 6,346	$ 99,426	$ 244,879	$ 14,693	$ 230,186	$ 311,545	$ 18,693	$ 292,853	$ 378,212	$ 22,693	$ 355,519	$ 444,879	$ 26,693	$ 418,186	$ 511,545	$ 30,693	$ 480,853
Grossed-up PILs		-$ 3,406	-$ 53,357		-$ 6,593	-$ 103,285		-$ 6,022	-$ 94,349		-$ 5,218	-$ 81,753		-$ 4,238	-$ 66,388		-$ 3,126	-$ 48,967
Revenue Requirement		$ 8,195	$ 128,389		$ 19,903	$ 311,806		$ 26,946	$ 422,150		$ 33,994	$ 532,576		$ 40,991	$ 642,193		$ 47,891	$ 750,287
Provincial Rate Protection			$ 128,389			$ 311,806			$ 422,150			$ 532,576			$ 642,193			$ 750,287
Monthly Amount Paid by IESO			$ 10,699			$ 25,984			$ 35,179			$ 44,381			$ 53,516			$ 62,524

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

Income Tax	2015 Direct Benefit	2015 Provincial	2016 Direct Benefit	2016 Provincial	2017 Direct Benefit	2017 Provincial	2018 Direct Benefit	2018 Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up								
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Income Tax	2019 Direct Benefit	2019 Provincial	2020 Direct Benefit	2020 Provincial	2021 Direct Benefit	2021 Provincial	2022 Direct Benefit	2022 Provincial	2023 Direct Benefit	2023 Provincial	2024 Direct Benefit	2024 Provincial
Net Income - ROE on Rate Base	$ 3,247	$ 50,863	$ 7,292	$ 114,246	$ 8,820	$ 138,183	$ 10,207	$ 159,909	$ 11,453	$ 179,424	$ 12,557	$ 196,728
Amortization (6% DB and 94% P)	$ 6,346	$ 99,426	$ 14,693	$ 230,186	$ 18,693	$ 292,853	$ 22,693	$ 355,519	$ 26,693	$ 418,186	$ 30,693	$ 480,853
CCA (6% DB and 94% P)	-$ 19,039	-$ 298,279	-$ 40,270	-$ 630,902	-$ 44,216	-$ 692,722	-$ 47,373	-$ 742,178	-$ 49,898	-$ 781,742	-$ 51,919	-$ 813,394
Taxable income	-$ 9,446	-$ 147,990	-$ 18,285	-$ 286,470	-$ 16,703	-$ 261,686	-$ 14,473	-$ 226,749	-$ 11,753	-$ 184,132	-$ 8,669	-$ 135,813
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	-$ 2,503.24	-$ 39,217.40	-$ 4,845.61	-$ 75,914.58	-$ 4,426.39	-$ 69,346.83	-$ 3,835.44	-$ 60,088.54	-$ 3,114.57	-$ 48,794.98	-$ 2,297.26	-$ 35,990.38
Gross Up												
Income Taxes Payable	$ (3,405.77)	$ (53,357.01)	$ (6,592.67)	$ (103,285.14)	$ (6,022.30)	$ (94,349.43)	$ (5,218.28)	$ (81,753.11)	$ (4,237.51)	$ (66,387.72)	$ (3,125.52)	$ (48,966.50)
Grossed Up PILs	-$ 3,406	-$ 53,357	-$ 6,593	-$ 103,285	-$ 6,022	-$ 94,349	-$ 5,218	-$ 81,753	-$ 4,238	-$ 66,388	-$ 3,126	-$ 48,967

Net Fixed Assets		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Enter applicable amortization in years:	15										
Opening Gross Fixed Assets		-	$ -	$-	$ -	$ -	$ 3,173,182	$ 4,173,182	$ 5,173,182	$ 6,173,182	$ 7,173,182
Gross Capital Additions		$ -	$ -	$-	$ -	$ 3,173,182	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
Closing Gross Fixed Assets		$ -	$ -	$-	$ -	$ 3,173,182	$ 4,173,182	$ 5,173,182	$ 6,173,182	$ 7,173,182	$ 8,173,182
Opening Accumulated Amortization		-	$ -	$-	$ -	$ -	$ 105,773	$ 350,652	$ 662,197	$ 1,040,409	$ 1,485,288
Current Year Amortization (before additions)		$ -	$ -	$-	$ -	$ -	$ 211,545	$ 278,212	$ 344,879	$ 411,545	$ 478,212
Additions (half-year)		$ -	$ -	$-	$ -	$ 105,773	$ 33,333	$ 33,333	$ 33,333	$ 33,333	$ 33,333
Closing Accumulated Amortization		$ -	$ -	$-	$ -	$ 105,773	$ 350,652	$ 662,197	$ 1,040,409	$ 1,485,288	$ 1,996,833
Opening Net Fixed Assets		$ -	$ -	$-	$ -	$ -	$ 3,067,409	$ 3,822,530	$ 4,510,985	$ 5,132,773	$ 5,687,894
Closing Net Fixed Assets		$ -	$ -	$-	$ -	$ 3,067,409	$ 3,822,530	$ 4,510,985	$ 5,132,773	$ 5,687,894	$ 6,176,349
Average Net Fixed Assets		$ -	$ -	$-	$ -	$ 1,533,705	$ 3,444,970	$ 4,166,758	$ 4,821,879	$ 5,410,333	$ 5,932,121

UCC for PILs Calculation

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening UCC		$ -	$ -	$-	$ -	$ -	$ 2,855,864	$ 3,184,691	$ 3,447,753	$ 3,658,202	$ 3,826,562
Capital Additions (from Appendix 2-FA)		$ -	$ -	$-	$ -	$ 3,173,182	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
UCC Before Half Year Rule		$ -	$ -	$-	$ -	$ 3,173,182	$ 3,855,864	$ 4,184,691	$ 4,447,753	$ 4,658,202	$ 4,826,562
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$-	$ -	$ 1,586,591	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Reduced UCC		$ -	$ -	$-	$ -	$ 1,586,591	$ 3,355,864	$ 3,684,691	$ 3,947,753	$ 4,158,202	$ 4,326,562
CCA Rate Class (to be entered)	8	8	8	8	8	8	8	8	8	8	8
CCA Rate (to be entered)	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
CCA		$ -	$ -	$-	$ -	$ 317,318	$ 671,173	$ 736,938	$ 789,551	$ 831,640	$ 865,312
Closing UCC		$ -	$ -	$-	$ -	$ 2,855,864	$ 3,184,691	$ 3,447,753	$ 3,658,202	$ 3,826,562	$ 3,961,249

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.3:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   iii) 2B-Staff-75 / parts (b), (c), (d)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Toronto Hydro's update to its response to interrogatory 2B-Staff-75 (b) is set out in Appendices A and B to this response.

Toronto Hydro's update to its response to interrogatory 2B-Staff-75 (c) and (d) are set out in Appendix C to this response.

U-Staff-166.3 Appendix A (Updated 2B-Staff-75 Appendix C)
Capital Programs Table

Programs ($M)	2015			2016			2017			2018			2019		
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var
Customer Connections Gross	53.9	69.2	15.3	67.4	67.7	0.2	81.1	59.5	(21.6)	76.0	90.6	14.6	67.7	105.7	38.0
Customer Connections Capital Contribution	(14.6)	(37.4)	(22.8)	(12.6)	(27.6)	(15.0)	(13.6)	(37.6)	(24.0)	(15.7)	(46.6)	(30.9)	(17.4)	(66.0)	(48.5)
Externally Initiated Plant Relocations & Expansion Gross	6.6	3.8	(2.9)	8.9	9.0	0.1	7.7	12.5	4.8	6.5	23.4	16.9	6.5	69.8	63.4
Externally Initiated Plant Relocations & Expansion Capital Contribution	(2.6)	(1.6)	1.0	(4.8)	(6.4)	(1.6)	(3.5)	(9.9)	(6.4)	(2.3)	(18.4)	(16.1)	(2.2)	(57.9)	(55.8)
Generation Protection, Monitoring, and Control	6.1	-	(6.1)	5.3	2.1	(3.2)	3.4	0.0	(3.4)	2.2	0.6	(1.6)	2.2	10.9	8.7
Load Demand	12.0	9.9	(2.1)	14.2	16.8	2.6	14.6	16.2	1.6	16.6	16.4	(0.3)	20.8	23.5	2.7
Metering	24.7	14.5	(10.2)	16.9	17.4	0.5	15.3	24.8	9.5	12.4	22.0	9.6	14.7	26.1	11.3
System Access Total	**86.1**	**58.3**	**(27.8)**	**95.3**	**79.0**	**(16.4)**	**104.9**	**65.5**	**(39.4)**	**95.8**	**88.0**	**(7.8)**	**92.3**	**112.1**	**19.8**
Area Conversions	33.8	46.3	12.4	29.4	28.2	(1.2)	32.7	26.9	(5.8)	33.8	34.4	0.5	39.3	36.0	(3.4)
Network System Renewal	9.6	10.2	0.7	21.4	16.8	(4.6)	21.8	14.7	(7.1)	22.0	18.8	(3.2)	22.6	32.2	9.6
Reactive and Corrective Capital	33.1	42.0	8.9	35.3	54.3	19.0	36.4	55.5	19.1	37.7	66.1	28.5	39.0	63.7	24.7
Stations Renewal	16.8	11.3	(5.5)	28.6	11.6	(17.0)	35.7	19.0	(16.8)	39.8	21.9	(18.0)	35.4	22.0	(13.5)
Underground System Renewal - Downtown	-	-	-	-	-	-	-	-	-	-	(0.0)	(0.0)	-	-	-
Underground System Renewal - Horseshoe	96.0	115.5	19.5	81.6	80.7	(0.9)	87.3	83.1	(4.2)	105.7	69.1	(36.6)	107.6	55.8	(51.8)
Overhead Infrastructure Relocation	0.7	0.9	0.1	1.4	3.1	1.7	1.9	2.6	0.7	2.4	0.3	(2.1)	3.9	1.6	(2.3)
SCADAMATE R1 Renewal	6.2	3.5	(2.7)	4.2	4.9	0.7	2.8	2.1	(0.7)	-	1.1	1.1	-	1.9	1.9
PILC Piece Outs & Leakers	3.5	6.0	2.6	1.4	5.7	4.3	0.8	1.8	1.1	0.9	0.8	(0.0)	0.6	0.1	(0.4)
Underground Legacy Infrastructure	2.1	7.4	5.4	6.8	9.9	3.1	6.9	9.0	2.1	6.9	2.7	(4.2)	6.0	6.0	0.1
Overhead System Renewal	44.0	61.0	17.0	23.4	51.0	27.6	25.9	35.7	9.8	26.8	30.4	3.6	32.8	24.8	(8.0)
System Renewal Total	**245.7**	**304.1**	**58.4**	**233.5**	**266.1**	**32.6**	**252.1**	**250.3**	**(1.9)**	**275.9**	**245.5**	**(30.4)**	**287.3**	**244.2**	**(43.1)**
Energy Storage Systems Gross	0.5	-	(0.5)	1.1	-	(1.1)	2.3	-	(2.3)	3.4	0.1	(3.4)	4.1	7.9	3.8
Energy Storage Systems Capital Contribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Network Condition Monitoring and Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Overhead Momentary Reduction	-	0.0	0.0	-	-	-	0.7	-	(0.7)	0.7	-	(0.7)	0.7	0.3	(0.4)
Stations Expansion	44.0	23.0	(21.0)	44.7	34.5	(10.2)	38.6	59.4	20.8	23.9	21.0	(2.9)	48.1	29.1	(19.1)
System Enhancements	21.7	7.1	(14.6)	23.2	17.2	(6.0)	21.7	12.2	(9.5)	22.7	9.4	(13.3)	25.4	4.0	(21.4)
Handwell Upgrades	5.0	4.7	(0.3)	-	0.8	0.8	-	0.8	0.8	-	0.0	0.0	-	-	-
Polymer SMD-20 Renewal	4.8	3.0	(1.8)	-	0.3	0.3	-	0.0	0.0	-	0.4	0.4	-	-	-
Design Enhancement	0.4	0.0	(0.4)	1.8	0.6	(1.1)	1.8	(0.0)	(1.8)	1.8	0.0	(1.8)	1.8	0.2	(1.6)
System Service Total	**76.5**	**37.9**	**(38.5)**	**70.7**	**53.3**	**(17.4)**	**65.1**	**72.4**	**7.4**	**52.6**	**31.0**	**(21.6)**	**80.2**	**41.5**	**(38.6)**
Facilities Management and Security	16.5	15.4	(1.1)	9.6	9.0	(0.5)	2.1	6.3	4.2	2.2	1.7	(0.4)	2.1	3.5	1.4
Fleet and Equipment	3.9	4.1	0.2	3.3	3.7	0.4	3.8	4.7	0.9	3.7	2.9	(0.8)	3.9	3.6	(0.3)
IT/OT Systems	51.8	28.4	(23.4)	79.1	48.6	(30.6)	28.3	55.4	27.0	28.3	53.7	25.4	24.3	39.3	15.0
Control Operations Reinforcement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Centers Consolidation Plan	37.4	31.6	(5.8)	15.1	48.3	33.1	0.1	32.2	32.1	-	-	-	-	-	-
Program Support	1.2	-	(1.2)	0.5	0.0	(0.5)	-	0.4	0.4	-	-	-	-	-	-
General Plant Total	**110.7**	**79.4**	**(31.2)**	**107.6**	**109.5**	**1.9**	**34.4**	**98.9**	**64.5**	**34.2**	**58.4**	**24.2**	**30.3**	**46.4**	**16.1**
AFUDC	8.0	10.8	2.8	5.9	12.5	6.7	4.7	9.8	5.1	4.9	8.9	4.0	5.0	4.0	(1.0)
Miscellaneous	4.2	2.7	(1.5)	5.7	(8.8)	(14.5)	6.2	0.9	(5.3)	6.6	3.8	(2.8)	7.1	(5.3)	(12.4)
Miscellaneous Capital Contribution	-	(1.9)	(1.9)	-	(0.0)	(0.0)	-	-	-	-	-	-	-	-	-
Other Total	**12.2**	**11.6**	**(0.6)**	**11.6**	**3.7**	**(7.8)**	**10.8**	**10.7**	**(0.1)**	**11.5**	**12.7**	**1.2**	**12.1**	**(1.3)**	**(13.4)**
Subtotal	**531.1**	**491.4**	**(39.7)**	**518.8**	**511.6**	**(7.2)**	**467.4**	**497.8**	**30.5**	**470.0**	**435.6**	**(34.4)**	**502.2**	**443.0**	**(59.2)**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.5)	(0.8)	(0.3)	(1.0)	(3.2)	(2.1)	(2.1)	(1.2)	0.9	(3.2)	(0.7)	2.6	(3.9)	(17.7)	(13.8)
Total	**530.6**	**490.6**	**(40.0)**	**517.7**	**508.4**	**(9.3)**	**465.2**	**496.6**	**31.4**	**466.8**	**434.9**	**(31.9)**	**498.3**	**425.3**	**(73.0)**

U-Staff-166.3 Appendix B (Updated 2B-Staff-75 Appendix D)
Capital Programs Table

Programs ($M)- In-service additions	2015	2016	2017	2018
	MIFRS	MIFRS	MIFRS	MIFRS
	Actual	Actual	Actual	Actual
Customer Connections Gross	66.8	51.6	53.5	54.9
Customer Connections Capital Contribution	(28.4)	(27.7)	(16.9)	(29.2)
Externally Initiated Plant Relocations & Expansion Gross	3.5	5.0	10.6	12.7
Externally Initiated Plant Relocations & Expansion Capital Contribution	(1.3)	(4.8)	(8.5)	(8.3)
Generation Protection, Monitoring, and Control	-	-	2.1	-
Load Demand	5.5	14.9	9.8	19.1
Metering	15.5	13.1	24.2	18.5
System Access Total	**61.7**	**52.1**	**75.1**	**67.7**
Area Conversions	44.0	34.1	35.3	14.8
Network System Renewal	6.8	15.7	12.8	9.3
Reactive and Corrective Capital	38.5	49.2	42.5	61.3
Stations Renewal	6.4	4.8	22.0	35.9
Underground System Renewal - Downtown	-	-	-	0.2
Underground System Renewal - Horseshoe	83.1	84.5	98.5	74.7
Overhead Infrastructure Relocation	3.8	1.4	1.2	3.3
SCADAMATE R1 Renewal	5.1	4.1	2.9	1.6
PILC Piece Outs & Leakers	8.9	3.4	3.9	1.6
Underground Legacy Infrastructure	7.0	8.6	4.4	2.4
Overhead System Renewal	60.8	65.6	40.5	34.1
System Renewal Total	**264.4**	**271.4**	**264.1**	**239.1**
Energy Storage Systems	-	-	-	-
Network Condition Monitoring and Control	-	-	-	-
Overhead Momentary Reduction	0.0	0.0	-	-
Stations Expansion	20.6	106.4	64.8	106.1
Stations Expansion Capital Contribution	-	-	-	(0.1)
System Enhancements	4.1	19.9	8.1	18.0
Handwell Upgrades	7.8	1.4	0.1	0.6
Polymer SMD-20 Renewal	1.6	2.2	0.0	0.4
Design Enhancement	0.0	0.3	0.2	0.0
System Service Total	**34.1**	**130.3**	**73.2**	**124.9**
Facilities Management and Security	21.3	17.9	8.7	6.9
Fleet and Equipment	2.9	3.7	4.5	3.7
IT/OT Systems	21.6	40.6	28.2	83.7
Control Operations Reinforcement	-	-	-	-
Operating Centers Consolidation Plan	28.5	67.5	67.6	-
Program Support	-	-	-	-
General Plant Total	**74.3**	**129.8**	**109.0**	**94.3**
AFUDC	-			-
Miscellaneous	1.2	1.1	4.2	(0.1)
Miscellaneous Capital Contribution	(0.4)	(0.4)	(3.4)	(1.5)
Other Total	**0.8**	**0.7**	**0.8**	**(1.6)**
Subtotal	**435.3**	**584.3**	**522.3**	**524.4**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)		-	(2.0)	-
Total	**435.3**	**584.3**	**520.3**	**524.4**

U-Staff-166.3 Appendix C (Updated 2B-Staff-75: Appendix E)

	Question	HONI (1)	HONI (2)	Copeland	ERP	OCCP	Radio Project	Telecom Program
a)	Name of the project	Expansion of Runnymede TS and Reconductoring of 115kV Transmission Circuits K1W, K3W, K11W and K12W	a) Toronto Midtown Transmission Reinforcement Project	Copeland Transformer Station - Phase 1	Enterprise Resource Planning	Operating Center Consolidation Program	Radio Project	Telecom Program
b)	Type of project/brief description of the project	The project consists of the expansion of Runnymede TS by installing two new 50/83MVA transformers and upgrading the KxW Transmission Corridor to supply the expanded Runnymede TS and maintain the reliability of the transmission supply to the area.	b) The project involves replacing, reconfiguring and installing additional transmission circuits that are at end of life to address overloading of the existing transmission lines between Leaside TS and Bridgman TS. This will also provide capacity for future load growth.	Please refer to document EB-2012-0064 Tab 4 Schedule B17 Section V3-General Scope.	As discussed in the 2015-2019 DSP (Exhibit 2B, E8.6), the utility detailed its need to replace the legacy system, Ellipse, in favour of a modern application to address significant reliability and cybersecurity risks.	The OCCP was a real estate initiative from 2014 to 2018, intended to: (i) ensure security of tenure at major crew-supporting operating centers; (ii) ensure the uninterrupted continuation of critical functions; and (iii) achieve permanent significant cost savings for ratepayers.	As discussed in the 2015-2019 DSP (Exhibit 2B, E8.7), the voice radio system is critical to Toronto Hydro's ability to safely and effectively deliver its planned capital and maintenance programs and to respond to trouble calls in a safe, timely and efficient manner.	As discussed in the 2015-2019 DSP (Exhibit 2B, E6.22), this program renews and improves the telecommunications system by identifying gaps in the communication service platform
c)	Year the project was originally forecasted to go in-service	2017	2010[1]	2016	2016	500 Commissioners (2015) 715 Milner (2016) 71 Rexdale (2016)	2016	2015 - 2018
d)	Year the project went in-service or is now forecasted to go in-service	2018-2019	2016	2019	2018	500 Commissioners (2016) 715 Milner (2017) 71 Rexdale (2016)	2017	2017 - 2019
e)	Originally plan budget for the project (in $ millions)	33.0	35.0	195.0	51.3	160.0	20.4	16.0
f)	Actual cost of the project or revised forecasted cost (in $ millions)	49.3	52.4	204.0	59.3	206.6	21.9	20.1
g)	Explanation for any variance in cost if actual/revised forecast is +/- 5% of the original budget amount	Original Class C estimate for the circuit re-conductoring work was based off a project that did not include: - Replacement of steel members (required on 90% of structures) in the 10km corridor - Construction complexities in working in a congested corridor in City of Toronto - More complex outage requirements at Manby, Runnymede and Wiltshire	As a result of an environmental and engineering study and engineering, it was recommended that a deep tunnel option would solve the congestion issues in the originally proposed rail corridor and city streets along the route which increased the cost of the project.	Please refer to Toronto Hydro's response to interrogatory 2B-Staff-95 part (c).	Please refer to Toronto Hydro's response to interrogatory U-Staff-166 a) iv) part c)	Please refer to Toronto Hydro's response to 2B-Staff-76 part (a)	Please refer to Toronto Hydro's response to interrogatory U-Staff-166 a) iv) part c)	Please refer to Toronto Hydro's response to interrogatory U-Staff-166 a) iv) part c)

[1] EB-2007-0680 (2008 COS) D2_T01_S01)

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.4:

Reference(s): Multiple Interrogatory and Undertaking Responses

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

iv) 2B-Staff-76 / part (c)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated Table below.

Table 1: Cost variance for IT/OT Program for the 2015-2019 period ($ Millions)

Program	CIR Plan	CIR Forecast	Variance	Variance Explanation (Updated)
ERP	51.3	59.3	8.0	The variance in the ERP program is attributable to the following factors: • an additional $4.9 million resulting from additional resources that were required for the project, changes in infrastructure costs following a more detailed technical assessment, and exchange rate fluctuations; • an additional $1.8 million resulting from a three month schedule extension to allow the alignment of various activities and streamline project related tasks; and

Program	CIR Plan	CIR Forecast	Variance	Variance Explanation (Updated)
				• an additional $1.3 million in subscription fees for SuccessFactors modules. These modules bring additional functionalities such as Compensation, Recruiting, Onboarding, Performance & Goals, Workforce Analytics & Planning and Employee Central;
IT Hardware & Software	117.7	116.5	-1.2	For the reasons discussed in section 1.5.4 of Exhibit U, Tab 2, Schedule 2, Toronto Hydro's actual IT Software cost in 2018 was less than forecast in the Application. The updated forecast expenditure in the CIR 2015-2019 period reflects the re-assessment of business needs in the IT Hardware & Software segment in 2018 following the implementation of the ERP and is expected to result in a variance of $1.2M or 1% below the originally planned program expenditures over the five-year period.
Voice Radio System	20.4	21.8	1.4	No update. As originally explained, the variance is attributable to the additional supporting infrastructure that was required to deploy the radio system, namely facilities work, power backup (UPS/generators), HVAC and redundant fiber-optic telecom links for the 10 radio antenna bearing high-sites that enable the P25 radio system to function.
Distribution System Comm.	16.0	20.1	4.1	$2.8 million of this variance is attributable to the added scope of completing the necessary facilities, telecom, and IT infrastructure investment to ensure business continuity in the event of a power disruption. The remaining $1.3 million of variance is attributable to higher than forecasted fiber-optic plant installation costs as well as the deployment of a more advanced, secure and future-proof telecom technology than what was available at the time of the original filing.
Total[1]	**205.4**	**217.7**	**12.3**	

Note 1: Totals may not add due to rounding.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.5:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

v) 2B-Staff-78 / parts (a), (b – add 2018 to Tables 3 and 4 and show the revised capital contribution percentage calculated using the 2014-2018 data and both Toronto Hydro's proposed weighted average methodology and a simple average methodology)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

The update to Toronto Hydro's response to interrogatory 2B-Staff-78 (a) is set out in Table 1 and Table 2 below.

Table 1: 2015-2019 Generation Connection Breakdown

Type		2015	2016	2017	2018	2019
Renewable / FIT	Forecast	424	300	296	300	161
	Actual	326	250	201	314	N/A
Natural Gas / CHP	Forecast	6	13	10	9	19
	Actual	2	0	4	10	N/A

Type		2015	2016	2017	2018	2019
Diesel / Other	**Forecast**	8	9	8	9	6
	Actual	2	3	2	0	N/A
Energy Storage	**Forecast**	0	0	0	0	24
	Actual	2	3	0	3	N/A

Note: All figures based on date of electrical connection.

Table 2: 2015-2019 Generation Capacity (MW) Breakdown

Type		2015	2016	2017	2018	2019
Renewable / FIT	**Forecast**	41.9	23.9	25.8	27.7	17
	Actual	27.5	14.7	10.0	12.0	N/A
Natural Gas / CHP	**Forecast**	35.5	28.2	27.3	24.0	27.6
	Actual	9.8	0	5.0	5.13	N/A
Diesel / Other	**Forecast**	32.9	18.0	8.0	15.0	21.7
	Actual	10.1	6.5	11.0	0	N/A
Energy Storage	**Forecast**	0	0	0	0	39.3
	Actual	0.7	0	0	1.95	N/A

The update to Toronto Hydro's response to interrogatory 2B-Staff-78 (b) is set out in Table 3, Table 4, and Table 5 below.

Table 3: Spend ($ Millions)

	2013	2014	2015	2016	2017	2018
Gross	77.1	65.6	68.3	67.1	58.7	81.1
Customer Contributions	(23.6)	(13.5)	(35.7)	(27.4)	(36.6)	(37.6)

Table 4: Escalated Spend ($ Millions in 2020 amounts)

	2013	2014 (1)	2015 (2)	2016 (3)	2017 (4)	2018 (5)
Gross (G_i)	88.5	73.9	75.4	72.6	62.2	84.4
Customer Contributions (CC_i)	(27.1)	(15.2)	(39.4)	(29.7)	(38.8)	(39.1)

Table 5: Weights (w_i)

Year	2013	2014 (1)	2015 (2)	2016 (3)	2017 (4)	2018 (5)
Weight (w)	N/A	6.7%	13.3%	20.0%	26.7%	33.3%

The weighted average capital contribution ratio was calculated on the same basis as the step-by-step process outlined in Toronto Hydro's response to interrogatory 2B-Staff-78 (b). The capital contribution ratio for 2014-2018 is 48 percent using the weighted average method and 44 percent using the simple average method.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.6:

Reference(s): Multiple Interrogatory and Undertaking Responses

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

vi) 2B-Staff-81 / part (c – add 2018 to Table 1 and provide 2015-2018 average)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: Historical Unit Costs for 2015-2018 for Major Units

Asset	2015	2016	2017	2018	2015-2018 Average	2020 Forecast[1]
Cable ($/m)	100	96	137[2]	123	**114**	115
Transformers ($/unit)	22,697	23,091	21,003[2]	25,619	**23,103**	22,767
Pad-Switch (S/unit)	83,479	81,611	81,798	88,470	**83,840**	87,333

[1] The 2020 forecast presented in this table is based on the 2015-2017 Average and escalated to 2020 dollars using 2 percent escalation per year as provided in Toronto Hydro's original response to 2B-Staff-81(c). To calculate an updated 2020 forecast based on the 2015-2018 Average, it should be escalacted twice (i.e. two years) using a 2 percent inflation factor.
[2] Please refer to Toronto Hydro's response to U-AMPCO-116.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.7:

Reference(s): Multiple Interrogatory and Undertaking Responses

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

vii) 2B-Staff-84 / parts (a), (b – update 2018 in Table 2 and provide updated unit costs for 2019-2024 based on the 2015-2018 data and Toronto Hydro's proposed weighted average methodology)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

The update to Toronto Hydro's response to part (a) of 2B-Staff-84 is set out in Table 1 below.

Table 1: 2015-2019 Overhead Units (Planned vs. Actual/Forecast)

Asset Class	2015		2016		2017		2018		2019	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast
Poles	3332	3656	1735	2692	1900	1513	1934	1510	2313	1330
Pole Top Transformers	972	940	511	769	478	441	598	412	673	320
Overhead Switches	294	192	160	167	166	120	154	90	207	13
Primary Conductor (km)	N/A	155	N/A	179	N/A	123	N/A	102	N/A	50

The update to Toronto Hydro's respone to part (b) of 2B-Staff-84 is set out in Table 2 and Table 3 below.

Table 2: 2015-2019 Major Overhead Assets Unit Costs ($)

Asset Class	Actuals				Forecast
	2015	2016	2017	2018	2019
Poles	7,880	7,538	7,225[1]	7,101	7,659
Pole Top Transformers	12,084	12,220	12,034[1]	10,771	12,152
Overhead Switches	21,994	26,359	20,004[1]	23,222	23,295
Primary Cables ($/km)	59,500	63,200	60,400	53,300	60,643

Table 3: Updated 2020-2024 Major Overhead Asset Unit Costs ($)

Asset Class	2020	2021	2022	2023	2024
Poles	7,812	7,968	8,128	8,290	8,456
Pole Top Transformers	12,395	12,643	12,896	13,154	13,417
Overhead Switches	23,761	24,236	24,721	25,215	25,719
Primary Cables ($/km)	61,856	63,093	64,355	65,642	66,955

[1] Please refer to Toronto Hydro's response to U-AMPCO-116.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.8:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

viii) 2B-Staff-91 / parts (b), (c)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

The update to Toronto Hydro's response to interrogatory 2B-Staff-91 (b) is that as of April 30, 2019, the utility spent $8.68 million on the Metrolinx ECLRT ESS project.[1] Please refer to Table 19 of Exhibit U, Tab 2, Schedule 2 at page 20 for a breakdown of expenditures for the project by year.

The update to Toronto Hydro's response to interrogatory 2B-Staff-91 (c) is that to date, Toronto Hydro has received $32.5 million in capital contributions from Metrolinx for the ECLRT ESS project.

[1] Due to rounding, investment on the Metrolinx ECLRT ESS project in 2018 was reported as $8.4 million in Exhibit U, Tab 2, Schedule 2 rather than $8.43 million.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.9:

Reference(s): Multiple Interrogatory and Undertaking Responses

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

ix) 3-Staff-107 / part (b)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the upated table below.

Table 1: Pole Attachment Revenues ($ Millions)

	Actual				Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Pole Attachment Revenue	3.2	4.1	5.6	5.9	5.0	5.5

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.10:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

x) 4A-Staff-112

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see Table 1 for an updated breakdown of the actual 2018 costs for the Disaster Preparedness Management program. There were no revisions to 2019 or 2020 forecasts.

Table 1: 2018 Internal vs External Program Costs ($ Millions)

Year	Total	Actual External Costs	Actual Internal Costs
2018	**2.9**	0.7	2.2

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.11:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

xi) 4A-Staff-128 / part (b)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: 2015-2020 Breakdown of Salary and Wages ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Base Salary	138.1	139.2	140.9	140.4	153.3	156.4
Overtime	12.6	12.7	13.1	17.1	12.2	12.4
Incentive Pay	7.5	8.4	9.1	9.2	10.5	10.7
Total	**158.3**	**160.3**	**163.1**	**166.7**	**176.0**	**179.4**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.12:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   xii) 4A-Staff-131 / part (b)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: Third-Party Service Provider Costs ($ Millions)

2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2018 Actual	2019 Bridge	2020 Test
385.6	398.5	398.3	370.9	383.1	365.0	417.7

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.13:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

xiii) 4A-Staff-138 / part (b)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: Net Revenue of Shared Services Provided by and Received by Toronto Hydro to/from THESI ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Services provided by Toronto Hydro						
Revenue	2.0	2.1	1.1	2.2	1.6	1.6
Costs	1.9	2.0	1.1	2.1	1.5	1.5
Services provided by Toronto Hydro (Net) [a]	**0.1**	**0.1**	**0.0**	**0.1**	**0.1**	**0.1**
Services received by Toronto Hydro [b]	**1.9**	**2.6**	**0.3**	**-**	**-**	**-**
Net Revenue/(Costs) of the Shared Services with THESI [a]-[b]	**(1.8)**	**(2.5)**	**(0.3)**	**0.1**	**0.1**	**0.1**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.14:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

a) Please update the following interrogatory responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

xiv) 9-Staff-154 / part (b-iv)

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: Calculation for the Actual/Bridge Capital-Related RR

	2015	2016	2017	2018	2019	2015-2019
ROE	119.2	130.8	143.8	153.5	163.9	711.3
Interest	78.6	86.2	94.8	102.2	108.3	470.0
Depreciation	190.5	206.1	216.7	229.2	245.4	1,087.9
PILS	25.2	26.2	25.8	19.0	21.7	117.8
TOTAL	**413.6**	**449.3**	**481.0**	**503.9**	**539.3**	**2,387.1**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.15:

Reference(s): Multiple Interrogatory and Undertaking Responses

b) Please update the following undertaking responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

   i) JTC1.10

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the upated response below.

TS Outdoor Circuit Breaker

The cost per unit for TS outdoor circuit breaker replacements increased between 2015-2019 planned expenditures and 2015-2019 actuals/forecasts due changes in scope, which were required to meet new Hydro One standards, as outlined in the pre-filed evidence at Exhibit 2B, Section E6.6, page 51:

> "For new breaker replacements, Hydro One requires a demarcation panel to act as a clean interface point between Toronto Hydro's and Hydro One's equipment, which would minimize confusion between the ownership of Hydro One and

Toronto Hydro assets. However, with these new requirements, Toronto Hydro was required to pay a capital contribution to Hydro One."

MS Switchgear

In Table 1 of the response to interrogatory 2B-Staff-85, an error was made in allocating the 2015-2019 planned expenditures between the TS Switchgear and the MS Switchgear sub-segments. A corrected Table 1 is provided below. With this correction in place, the variance between planned and actual/forecast expenditures for MS Switchgear assets is $1.7 million, which represents a 12 percent increase in the cost per unit.

For all other sub-segments listed in Table 1, please refer to Exhibit 2B, Section E6.6.4 for the variance explanations.

Table 1: 2015-2019 Stations Renewal Program Variance Analysis ($ Millions)

Sub Segment	2015-2019 Planned		2015-2019 Forecast		Variance from Planned	
	Expenditure	Units	Expenditure	Units	Expenditure	Units
TS Switchgear	~~96.9~~ 92.5	9	23.7	3	(68.8)	-6
TS Outdoor Breakers	9.1	35	13.0	26	3.9	-9
MS Switchgear	~~9.4~~ 13.7	11	15.4	11	1.7	0
Power Transformer	12.3	24	13.3	16	1.0	-8
DACSCAN RTU	1.6	6	1.7	3	0.1	-3
MOSCAD RTU	1.0	22	4.7	24	3.7	+2
D20 RTU	-	0	0.1	1	0.1	+1
New RTU Installations	0.4	7	1.8	5	1.4	-2
Pilot-wire Protection	2.1	9	3.5	5	1.4	-4
Battery and Charger	3.1	67	4.5	48	1.4	-19
SST	0.3	1	1.3	3	1.0	+2
Air Compressor Replacements	0.3	6	0.1	0	(0.2)	-6
Sump Pump Installations	-	0	0.6	1	0.6	+1

Sub Segment	2015-2019 Planned		2015-2019 Forecast		Variance from Planned	
	Expenditure	Units	Expenditure	Units	Expenditure	Units
Fire Barrier/Suppression Systems	0.7	3	2.3	2	1.6	-1
Fire Alarm Systems[1]	1.0	5	n/a	n/a	(1.0)	-5
TS Outdoor Switch	*New to 2020-2024 Program*					
MS Primary Supply	*New to 2020-2024 Program*					
Interstation Control Wiring	*New to 2020-2024 Program*					
	138.2	**-**	**86.0**	**-**	**(52.2)**	**-**

Note 1: Fire alarm systems were removed from the Stations Renewal program. Please refer to Exhibit 2B, Section 8.2 for further information on capital spending related to stations fire alarm systems.

Variances between JTC1.10 and U-Staff-166

Table 2, below, provides a variance analysis between the forecasts provided in Toronto Hydro's reponse to JTC1.10 and Table 1 above. On the whole of the program, the net expenditure has been maintained; however there have been changes to the number of units for some sub segments.

Table 2: JTC1.10 and U-Staff-166 Variance Analysis ($ Millions)

Sub Segment	2015-2019 Forecast (JTC1.10)		2015-2019 Forecast (U-Staff-166)		Variance from JTC1.10	
	Expenditure	Units	Expenditure	Units	Expenditure	Units
TS Switchgear	30.2	3	23.7	3	(6.5)	0
TS Outdoor Breakers	11.8	28	13.0	26	1.2	-2
MS Switchgear	14.6	11	15.4	11	0.8	0
Power Transformer	11.3	15	13.3	16	2.0	1
DACSCAN RTU	2.0	4	1.7	3	(0.3)	-1
MOSCAD RTU	4.0	24	4.7	24	0.7	0
D20 RTU	0.1	1	0.1	1	0.0	0
New RTU Installations	1.6	5	1.8	5	0.2	0
Pilot-wire Protection	3.3	9	3.5	5	0.2	-4
Battery and Charger	3.6	44	4.5	48	0.9	4
SST	0.8	3	1.3	3	0.5	0
Air Compressor Replacements	0.4	4	0.1	0	(0.3)	-4

Sub Segment	2015-2019 Forecast (JTC1.10)		2015-2019 Forecast (U-Staff-166)		Variance from JTC1.10	
	Expenditure	Units	Expenditure	Units	Expenditure	Units
Sump Pump Installations	0.1	1	0.6	1	0.5	0
Fire Barrier/Suppression Systems	1.3	2	2.3	2	1.0	0
Fire Alarm Systems[1]	n/a	n/a	n/a	n/a	0.0	0
TS Outdoor Switch	*New to 2020-2024 Program*					
MS Primary Supply	*New to 2020-2024 Program*					
Interstation Control Wiring	*New to 2020-2024 Program*					
	85.3	**-**	**86.0**	**-**	**(0.7)**	**-**

As noted in the Application Update (Exhibit U, Tab 2, Schedule 2, page 15), within the Transformer Stations and Municipal Stations segments, Toronto Hydro deferred some TS switchgear expenditures due to site-specific complexities and deferred two TS breaker replacements to accommodate funding for a higher priority MS power transformer replacement. Additional details are provided below. Please see Exhibit U, Tab 2, Schedule 2, pages 15-16 for discussion of variances within the Control and Monitoring and Battery and Ancillary Systems segments.

<u>TS Switchgear</u>

Toronto Hydro spent $6.5 million less than previously planned on TS switchgear due to delays in the Duplex TS (A1-2DX) and Strachan TS (A5-6T) switchgear replacements.

Duplex TS (A1-2DX)

Toronto Hydro has proposed several replacement options for the Duplex TS switchgear replacement; but due to the space constraints at the station, Toronto Hydro and Hydro One have not yet found an acceptable solution. At the time of filing, the project was expected to begin in 2019. These expenditures have been deferred to the 2020-2024 period.

Strachan TS (A5-6T)

Work on the A5-6T switchgear has been delayed due to delays in another project at the station, specifically the replacement of the A7-8T switchgear. As Toronto Hydro is replacing its A7-8T switchgear, a need exists for Hydro One to also renew a power transformer and associated cables at Strachan TS. This has resulted in coordination challenges, both from an electrical (operational) and physical (execution) perspective, and delays that have been driven by a desire to not expose customers in the Strachan area to an unacceptable risk of power outages. Toronto Hydro has had to defer the replacement of the A5-6T switchgear into the 2020-2024 period as this project cannot begin until the completion of the A7-8T replacement.

<u>TS Outdoor Breakers</u>

Toronto Hydro expects to complete two fewer breaker replacements and to spend $1.2 million more than previously forecast. The utility deferred two outdoor circuit breaker replacements to the 2020-2024 period due to higher than expected spending in this sub-segment as a whole, and to transfer budget to permit an additional higher priority power transformer replacement. Increases in costs for this work are described at the bottom of page 1 of this response.

<u>Power Transformer</u>

Toronto Hydro expects to spend an additional $2.0 million on power transformers and complete one additional unit. This unit was identified as posing unacceptable risk and was added to the program. Approximately half of the total variance is the result of adding the unit to the program. The remaining variance resulted from construction complexities within a subset of three transformer replacement projects.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.16:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

b) Please update the following undertaking responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

ii) JTC1.15

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see the updated table below.

Table 1: Derecognition Expense as Percent of In-Service Additions ($ Millions)

	2015	2016	2017	2018
Derecognition	24.1	27	24.5	24.5
In Service Additions	435.3	584.3	522.3	524.4
% Derecognition vs. In Service Additions	5.55%	4.62%	4.70%	4.67%

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 166.17:

Reference(s): **Multiple Interrogatory and Undertaking Responses**

b) Please update the following undertaking responses to include 2018 actuals (and revised 2019 forecasts) as appropriate:

iii) JTC 4.3

For all interrogatories and undertakings where excel spreadsheets have been previously provided, please provide updated excel spreadsheets.

RESPONSE:

Please see Table 1 for the calculation of ESM based on Toronto Hydro's understanding of Board Staff's request in 1B-Staff-25 part (g) ("ROE Method"). Table 2 shows the adjustments for rate riders and out of period amounts.

As noted in response to JTC4.3, the ROE Method is not consistent with the OEB Decision in the last rate application, which required the ESM account to track the variance between the non-capital related revenue requirement embedded in rates and the actual non capital related revenue requirement.[1]

[1] EB-2014-0116, Decision and Order (December 29, 2015) at page 49.

Table 1: ESM Calculation per 1B-Staff-25(g) ($ Millions)

		2015	2016	2017	2018
Earnings as per RRR 2.1.5.6	A	137.7	173.0	139.8	153.9
Adjustments (see Table 2)	B	- 20.9	- 47.2	- 9.6	-15.9
Adjusted Earnings	**C=A+B**	116.8	125.8	130.2	138.0
Less: Earnings (funded through base rates)[2]	D	- 120.2	- 132.3	- 143.2	-149.2
Earnings Variance	E=C+D	- 3.5	- 6.5	- 13.0	-11.2
Actual Deemed Equity as per 2.1.5.6 (box "x1")	F	1,285.2	1,420.1	1,540.4	1,649.5
ESM Variance	G=E/F	0.27%	0.45%	0.84%	0.68%
Threshold	H	1.00%	1.00%	1.00%	1.00%
Result	G compared to H	ESM not triggered	ESM not triggered	ESM not triggered	ESM not triggered

[2] Determined based on the annual ROE included in Table 2 of the EB-2014-0116 Draft Rate Order Update (February 29, 2016, page 6), less 0.6% stretch factor.

1 **Table 2: Adjustments to Net Income in Table 1 Above ($ Millions)**

Description	Category[3,4]	2015	2016	2017	2018
Lost Revenue Adjustment Mechanism	DVA	-9.0	-4.5	-9.6	-15.9
Monthly Billing	DVA	-	0.4	-	-
Smart Meter Recognition	DVA & Out of Period	-10.9	-7.9	-	-
Amortization of return on IFRS transition costs (account 1575)	DVA & Out of Period	-	-0.9	-	-
Incremental Capital Module (Distribution Revenue, less Depreciation)	DVA & Out of Period	-	-30.3	-	-
Harmonized Sales Tax	DVA & Out of Period	-	1.1	-	-
HONI Contribution	DVA & Out of Period	-1.9	-	-	-
Named Properties	DVA & Out of Period	-5.8	-	-	-
POEB Tax Savings	Out of Period	0.9	-	-	-
Rate/ Fiscal year synchronization	Unrelated to Non-Capital Rev. Requirement	22.0	-	-	-
PILs consequences of foregone revenue	DVA	-16.2	-5.1	-	-
Total Adjustments		**-20.9**	**-47.2**	**-9.6**	**-15.9**

[3] Out of period items represent earnings recognized in 2015-2018 but pre-dating 2015. These are adjusted as they do not form base rates for 2015-2018.
[4] DVA items represent earnings related to deferral and variance accounts which are recognized in 2015-2018. These are adjusted as they do not form base rates for 2015-2018.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 167:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 6

Preamble:

Toronto Hydro stated that the debt to equity ratio was 1.20 in 2018 compared with 1.34 in 2017. The 2018 value reflects the provision of approximately $43 million in dividends in 2018.

a) Please further explain the change to the debt to equity ratio and provide the calculation.

RESPONSE:

a) Refer to Table 1 below for the debt to equity ratio calculation for 2017 and 2018.

Table 1: Debt to Equity Ratio ($ Millions)

	2017	2018	Variance
Debt:			
2225 Notes and Loans Payable	156.7	57.6	(99.1)
2242 Notes Payable to Associated Companies	60.0	304.9	244.9
2550 Advances from Associated Companies	2,029.9	1,785.7	(244.2)
Total Debt (A)	**2,246.6**	**2,148.2**	**(98.4)**
Equity:			
3005 Common Shares Issued	527.8	527.8	-
3010 Contributed Surplus	12.8	12.8	-
3045 Unappropriated Retained Earnings	1,307.2	1,451.9	144.7
3046 Balance Transferred from Income	144.7	159.6	14.9

	2017	2018	Variance
3049 Dividends Payable - Common Shares	(323.6)	(366.3)	(42.7)
3055 Adjustments to Retained Earnings	5.9	5.7	(0.2)
Total Equity (B)	**1,674.8**	**1,791.5**	**116.7**
Total Debt/Total Equity = A/B	**1.34**	**1.20**	**(0.14)**

The lower debt to equity ratio in 2018 compared to 2017 was primarily due to:

1. Lower total debt in 2018 as a result of lower bank indebtedness (2225 Notes and Loans Payable) due to the sale of 5800 Yonge; and
2. Higher total equity in 2018 due to higher net income, partially offset by provision of dividends.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 168:

Reference(s): Exhibit U, Tab 2, Schedule 1, pp. 1-2, 8-9
Exhibit U, Tab 2, Schedule 2, p. 21

Preamble:

Toronto Hydro provided an updated rate base summary table as follows:

	OEB Approved[1]	Actual				Bridge	Forecast
	2015	2015	2016	2017	2018	2019	2020
Opening PP&E NBV	2,849.0	2,843.2	3,085.4	3,462.0	3,744.7	4,038.8	4,270.4
Closing PP&E NBV	3,134.7	3,085.4	3,462.0	3,744.7	4,038.8	4,232.3	4,489.8
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,891.8**	**4,135.6**	**4,380.1**
Working Capital Allowance	240.2	247.9	275.8	247.4	232.1	287.2	235.2
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,123.9**	**4,422.7**	**4,615.3**

Toronto Hydro also provided an updated construction work in progress (CWIP) summary table as follows:

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Opening CWIP	522.1	577.7	502.9	485.8	396.4	343.5
Additions (CAPEX)	490.6	508.4	496.6	434.9	425.3	514.0
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(524.4)	(440.6)	(489.8)
Other	0.3	1.1	6.5	0.0	-	-
Closing CWIP	577.7	502.9	485.8	396.4	381.1	367.7

Toronto Hydro stated that its 2020 rate base forecast is unchanged as the impact of rate base variances in 2018 and 2019 on the forecast net fixed asset component of 2020 rate base will be less than 1%. Toronto Hydro also proposes no changes to its 2020 in-service additions (ISAs).

In a number of places throughout the capital expenditure-related evidence update, Toronto Hydro stated that capital projects (and associated costs) have moved into the 2020-2024 period. For example, with respect to capital contributions to Hydro One for the Horner TS, Toronto Hydro stated that it deferred contributions to the 2020-2024 period.

a) Please confirm that it is Toronto Hydro's proposal to maintain the 2020 opening PP&E NBV amount of $4,270.4 million in the context that the 2019 closing PP&E NBV amount is $4,232.3 million. If so, please explain why this is appropriate.

b) Please confirm that it is Toronto Hydro's proposal to make no changes to its 2020 in-service addition (ISA) forecast ($489.8 million) (or 2021-2024 ISA forecasts) in the context that there were changes to 2018 actual ISAs and 2019 forecast ISAs (and there are a number of projects specifically referenced where changes are expected to occur during the IR term). If so, please explain why this is appropriate.

RESPONSE:

a) Toronto Hydro forecasts that its 2020 PP&E NBV amount will be within 1% of the amount originally filed. The forecast variance is caused by CWIP balances that are largely expected to be in service in 2020. As set out in Appendices A and B to this interrogatory response, Toronto Hydro is updating its 2020-2024 rate base evidence in relation to the CWIP balance.

b) As presented in Exhibit U, Tab 2, Schedule 1, page 2, Table 2, the forecasted 2019 Closing CWIP in the application update is $381.1 million, compared to the $343.5 million that was presented in Exhibit 2A, Tab 2, Schedule 1, Table 1 of the pre-filed evidence. Toronto Hydro has revised its 2020 in-service addition (ISA) forecast to reflect the impact of projects that were delayed from 2019 to 2020. ISA variance explanations for 2018-2019 are provided in response to U-Staff-170, parts (c) and (d). As a result of these deferrals, the current ISA forecast is $39 million lower than the pre-filed schedule, excluding external demand and non-rate base ISAs as shown in the table below.

Table 1: 2018-2019 ISA Variance

Category	2019 ISA Requirement	2019 Forecast	Variance
Distribution Capital Projects	390.0	375.9	(14.1)
Metering Data Collection Systems	9.5	7.0	(2.5)
Hydro One Contributions	14.7	4.0	(10.7)
IT Projects	52.4	40.7	(11.7)
Subtotal	**466.6**	**427.6**	**(39.0)**

Toronto Hydro expects to make-up the majority of this variance in 2020 from carry-over projects totalling an estimated $33.9 million in ISAs. These outstanding projects require an incremental $3.2 million in capital expenditures to be completed and placed into service in 2020, as shown in Table 2 below. The remaining ISAs variance is substantially attributed to a $4.6 million refund from Hydro One associated with the Runnymede TS circuit upgrade project. This refund resulted from the over-collection of capital contributions from Toronto Hydro. The amounts were refunded following a Capital Cost Recovery Agreement true up of the actual costs incurred in the project.

Table 2: Carryover Projects for 2020 ISA

Category	DSP Category	Capital Program	# of Projects	2020 ISA ($M)	2020 CapEx ($M)
Distribution Capital	System Service	Network Condition Monitoring and Control	2	2.3	0.4
Distribution Capital	System Renewal	Stations Renewal	5	12.6	0.5
Distribution Capital	System Renewal	Area Conversions	2	5.1	0.5
Distribution Capital	System Renewal	Underground System Renewal – Horseshoe	1	1.6	-
Distribution Capital			**10**	**21.6**	**1.4**
Metering Data Collection Systems	System Access	Metering	1	4.5	1.0
Metering Data Collection Systems			**1**	**4.5**	**1.0**
Hydro One Contributions	System Service	Stations Expansion	1	4.0	-
Hydro One Contributions			**1**	**4.0**	**-**
IT Projects	General Plant	IT/OT Systems	1	3.9	0.8
IT Projects			**1**	**3.9**	**0.8**
Subtotal			**13**	**33.9**	**3.2**
HONI Refund (Unplanned)		Stations Expansion	1	4.6	-
Total			**14**	**38.5**	**3.2**

Toronto Hydro has filed updated 2020-2024 Fixed Asset Continuity Schedules as Appendix A to this response. These schedules reflect the updated ISAs from the projects listed above, as well as other changes in the 2015-2019 period which resulted / C in changes in the mix of 2019 closing CWIP relative to the original pre-filed evidence.

Table 3 reflects the updated Rate Base amounts for 2020 resulting from the above / C noted changes.

Table 3: Updated Rate Base

	OEB Approved[1]	Actual				Bridge	Forecast
	2015	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Opening PP&E NBV	**2,849.0**	**2,843.2**	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,233.4**
Closing PP&E NBV	**3,134.7**	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,506.0**
Average PP&E NBV	**2,991.8**	**2,964.3**	**3,273.7**	**3,603.4**	**3,891.8**	**4,135.6**	**4,369.7**
Working Capital Allowance	**240.2**	**247.9**	**275.8**	**247.4**	**232.1**	**287.2**	**235.2**
Rate Base	**3,232.0**	**3,212.2**	**3,549.5**	**3,850.8**	**4,123.9**	**4,422.7**	**4,604.9**

Table 4 below shows the updated 2020-2024 Capital Related Revenue Requirement which also captures the PILs changes resulting from Bill C-97. The overall impact is a $63.8 million reduction to the forecast 2020-2024 Capital Related Revenue Requirement compared to pre-filed evidence, $54.9 million of which is related to the PILs changes.

Table 4: Updated Revenue Requirement

	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
ROE	162.5	170.8	179.5	189.7	199.2	**901.7**
Deemed Interest	100.6	105.7	111.1	117.4	123.3	**558.2**
Depreciation	265.5	281.5	292.3	314.0	327.1	**1,480.5**
PILS	12.8	22.2	13.6	27.9	40.5	**117.0**
Capital Related RR	**541.4**	**580.3**	**596.5**	**649.0**	**690.2**	**3,057.4**

Appendix B to this response provides revisions to other capital expenditures and rate base summary tables that are affected by the above noted changes. This includes:

- Exhibit U, Tab 2, Schedule 1, Page 4, Table 3: Gross and Net PP&E – Years Ending in December 31 ($ Millions);

- Exhibit U, Tab 2, Schedule 1, Page 7, Table 6: 2019 Bridge versus 2020 Forecast ($ Millions);
- Exhibit U, Tab 2, Schedule 1, Page 8, Table 7: Breakdown of Ending Balance of Gross Assets by Function ($ Millions);
- Exhibit U, Tab 2, Schedule 1, Appendix C: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account;
- Exhibit U, Tab 4B, Schedule 1, Appendix A: Summary of Depreciation Expense;
- Exhibit U, Tab 4B, Schedule 1, Page 2, Table 3: Depreciation and Amortization Expense 2015 to 2020 ($ Millions);
- Exhibit U, Tab 2, Schedule 2, Appendix B: OEB Appendix 2-AB;
- Exhibit U, Tab 2, Schedule 2, Appendix C: OEB Appendix 2-AB (JTC1.2); and
- Exhibit U, Tab 2, Schedule 1, Page 2, Table 2: Historical, Bridge and Forecasted Construction Work In Progress ($ Millions).

Toronto Hydro has also provided an updated Appendix 2-AA (with additional variance columns) in its response to interrogatory U-VECC-71.

Toronto Hydro proposes to update the cost allocation and rates information during the draft rate order process.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2020

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 247,940,281	$ 41,602,565	$ -	$ 289,542,846	($ 124,697,201)	($ 32,653,777)	$ -	($ 157,350,978)	$ 132,191,868
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 146,603,541	$ 3,545,980	$ -	$ 150,149,521	($ 16,315,310)	($ 3,719,188)	$ -	($ 20,034,497)	$ 130,115,023
47	1815	Transformer Station Equipment >50 kV	$ 38,893,291	$ 146,098	$ -	$ 39,039,389	($ 4,500,900)	($ 1,387,410)	$ -	($ 5,888,310)	$ 33,151,079
47	1820	Distribution Station Equipment <50 kV	$ 233,896,334	$ 32,875,896	($ 326,796)	$ 266,445,433	($ 46,700,148)	($ 10,856,456)	$ 95,923	($ 57,460,681)	$ 208,984,752
47	1830	Poles, Towers & Fixtures	$ 402,570,951	$ 42,684,885	($ 6,898,194)	$ 438,357,642	($ 56,695,908)	($ 11,871,898)	$ 927,888	($ 67,639,918)	$ 370,717,724
47	1835	Overhead Conductors & Devices	$ 468,238,300	$ 61,492,935	($ 2,629,678)	$ 527,101,556	($ 54,922,627)	($ 12,475,862)	$ 283,889	($ 67,114,600)	$ 459,986,957
47	1840	Underground Conduit	$ 1,306,119,180	$ 141,110,831	($ 668,559)	$ 1,446,561,452	($ 246,475,756)	($ 51,782,108)	$ 98,099	($ 298,159,766)	$ 1,148,401,686
47	1845	Underground Conductors & Devices	$ 955,851,966	$ 124,881,819	($ 5,903,043)	$ 1,074,830,742	($ 127,818,888)	($ 29,865,268)	$ 560,001	($ 157,124,156)	$ 917,706,587
47	1850	Line Transformers	$ 640,828,362	$ 102,119,136	($ 11,048,456)	$ 731,899,043	($ 122,498,051)	($ 27,962,577)	$ 1,545,228	($ 148,915,400)	$ 582,983,643
47	1855	Services (Overhead & Underground)	$ 141,412,397	$ 25,045,715	($ 398,088)	$ 166,060,024	($ 14,620,528)	($ 3,358,705)	$ 22,965	($ 17,956,268)	$ 148,103,756
47	1860	Meters	$ 105,053,832	$ 25,640,095	($ 1,022,851)	$ 129,671,076	($ 21,901,280)	($ 5,159,847)	$ 140,733	($ 26,920,394)	$ 102,750,682
47	1860	Meters (Smart Meters)	$ 138,842,990	$ 11,966,039	($ 713,141)	$ 150,095,888	($ 60,798,152)	($ 12,293,423)	$ 163,557	($ 72,928,019)	$ 77,167,870
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 240,619,777	$ 2,944,360	$ -	$ 243,564,137	($ 48,906,069)	($ 11,356,784)	$ -	($ 60,262,853)	$ 183,301,284
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 20,438,655	$ 1,053,325	$ -	$ 21,491,979	($ 11,414,206)	($ 1,886,440)	$ -	($ 13,300,646)	$ 8,191,333
50	1920	Computer Equipment - Hardware	$ 74,159,596	$ 15,123,254	$ -	$ 89,282,850	($ 50,494,297)	($ 11,199,443)	$ -	($ 61,693,740)	$ 27,589,110
10	1930	Transportation Equipment	$ 41,078,692	$ 4,604,061	$ -	$ 45,682,753	($ 27,822,725)	($ 3,150,222)	$ -	($ 30,972,947)	$ 14,709,806
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 28,881,401	$ 15,356,838	$ -	$ 44,238,240	($ 13,765,998)	($ 3,017,290)	$ -	($ 16,783,288)	$ 27,454,951
8	1945	Measurement & Testing Equipment	$ 499,679	$ 85,246	$ -	$ 584,925	($ 395,908)	($ 50,414)	$ -	($ 446,322)	$ 138,604
8	1950	Service Equipment	$ 1,387,956	$ 120,323	$ -	$ 1,508,279	($ 743,037)	($ 127,564)	$ -	($ 870,602)	$ 637,677
8	1955	Communications Equipment	$ 50,690,668	$ 1,263,248	$ -	$ 51,953,916	($ 19,759,473)	($ 4,395,505)	$ -	($ 24,154,978)	$ 27,798,938
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 223,012)	($ 34,271)	$ -	($ 257,284)	$ 13,694
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 52,079,297	$ 18,811,881	($ 627,898)	$ 70,263,279	($ 14,532,254)	($ 3,652,397)	$ 67,859	($ 18,116,791)	$ 52,146,488
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 235,243,420)	($ 146,273,553)	$ 565,896	($ 380,951,077)	$ 22,047,976	$ 8,804,137	($ 28,847)	$ 30,823,265	($ 350,127,811)
N/A	1609	Capital Contributions Paid	$ 190,469,722	$ 29,784,498	$ -	$ 220,254,219	($ 17,995,699)	($ 8,256,701)	$ -	($ 26,252,400)	$ 194,001,820
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 12,323,115)	($ 676,393)	$ -	($ 12,999,508)	$ 6,748,206
		Sub-Total	**$ 5,339,480,967**	**$ 555,985,474**	**($ 29,670,808)**	**$ 5,865,795,633**	**($ 1,098,056,306)**	**($ 242,385,809)**	**$ 3,877,295**	**($ 1,336,564,821)**	**$ 4,529,230,812**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 2,730,141)	($ 5,828,584)	$ -	($ 8,558,725)	$ 34,127	$ 410,729	$ -	$ 444,856	($ 8,113,869)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 5,704,285)	($ 10,214,512)	$ -	($ 15,918,797)	$ 369,444	$ 469,291	$ -	$ 838,735	($ 15,080,062)
		Total PP&E	**$ 5,331,046,541**	**$ 539,942,378**	**($ 29,670,808)**	**$ 5,841,318,111**	**($ 1,097,652,736)**	**($ 241,505,789)**	**$ 3,877,295**	**($ 1,335,281,230)**	**$ 4,506,036,881**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 241,505,789)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 239,746,268)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2021

CCA Class	OEB Account	Description	Cost (Forecast) Opening Balance	Cost (Forecast) Additions	Cost (Forecast) Disposals	Cost (Forecast) Closing Balance	Accumulated Depreciation (Forecast) Opening Balance	Accumulated Depreciation (Forecast) Additions	Accumulated Depreciation (Forecast) Disposals	Accumulated Depreciation (Forecast) Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 289,542,846	$ 37,040,209	$ -	$ 326,583,055	($ 157,350,978)	($ 35,750,756)	$ -	($ 193,101,734)	$ 133,481,321
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 150,149,521	$ 5,054,020	$ -	$ 155,203,541	($ 20,034,497)	($ 3,846,016)	$ -	($ 23,880,514)	$ 131,323,027
47	1815	Transformer Station Equipment >50 kV	$ 39,039,389	$ 117,028	$ -	$ 39,156,416	($ 5,888,310)	($ 1,429,995)	$ -	($ 7,318,304)	$ 31,838,112
47	1820	Distribution Station Equipment <50 kV	$ 266,445,433	$ 25,064,669	($ 341,165)	$ 291,168,937	($ 57,460,681)	($ 11,786,856)	$ 100,136	($ 69,147,402)	$ 222,021,535
47	1830	Poles, Towers & Fixtures	$ 438,357,642	$ 35,702,172	($ 7,314,181)	$ 466,745,633	($ 67,639,918)	($ 12,701,325)	$ 967,637	($ 79,373,607)	$ 387,372,027
47	1835	Overhead Conductors & Devices	$ 527,101,556	$ 51,007,558	($ 2,787,782)	$ 575,321,332	($ 67,114,600)	($ 13,710,100)	$ 297,886	($ 80,526,814)	$ 494,794,518
47	1840	Underground Conduit	$ 1,446,561,452	$ 112,903,055	($ 703,712)	$ 1,558,760,795	($ 298,159,766)	($ 56,331,901)	$ 102,019	($ 354,389,647)	$ 1,204,371,148
47	1845	Underground Conductors & Devices	$ 1,074,830,742	$ 104,656,787	($ 6,282,985)	$ 1,173,204,545	($ 157,124,156)	($ 32,368,162)	$ 594,838	($ 188,897,480)	$ 984,307,065
47	1850	Line Transformers	$ 731,899,043	$ 84,331,281	($ 11,603,645)	$ 804,626,678	($ 148,915,400)	($ 29,981,285)	$ 1,621,305	($ 177,275,379)	$ 627,351,299
47	1855	Services (Overhead & Underground)	$ 166,060,024	$ 20,715,062	($ 425,950)	$ 186,349,135	($ 17,956,268)	($ 3,715,367)	$ 24,571	($ 21,647,064)	$ 164,702,071
47	1860	Meters	$ 129,671,076	$ 16,187,757	($ 1,017,640)	$ 144,841,193	($ 26,920,394)	($ 5,618,339)	$ 140,016	($ 32,398,717)	$ 112,442,476
47	1860	Meters (Smart Meters)	$ 150,095,888	$ 7,996,296	($ 428,284)	$ 157,663,900	($ 72,928,019)	($ 12,056,011)	$ 98,156	($ 84,885,874)	$ 72,778,027
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 243,564,137	$ 4,470,732	$ -	$ 248,034,869	($ 60,262,853)	($ 11,386,791)	$ -	($ 71,649,644)	$ 176,385,225
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 21,491,979	$ 1,602,715	$ -	$ 23,094,695	($ 13,300,646)	($ 1,522,209)	$ -	($ 14,822,855)	$ 8,271,840
50	1920	Computer Equipment - Hardware	$ 89,282,850	$ 10,942,287	$ -	$ 100,225,137	($ 61,693,740)	($ 11,577,822)	$ -	($ 73,271,562)	$ 26,953,575
10	1930	Transportation Equipment	$ 45,682,753	$ 8,317,935	$ -	$ 54,000,688	($ 30,972,947)	($ 3,603,064)	$ -	($ 34,576,011)	$ 19,424,676
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 44,238,240	$ 19,467,406	$ -	$ 63,705,645	($ 16,783,288)	($ 3,955,827)	$ -	($ 20,739,115)	$ 42,966,530
8	1945	Measurement & Testing Equipment	$ 584,925	$ 229,524	$ -	$ 814,449	($ 446,322)	($ 40,379)	$ -	($ 486,700)	$ 327,749
8	1950	Service Equipment	$ 1,508,279	$ 248,660	$ -	$ 1,756,939	($ 870,602)	($ 130,733)	$ -	($ 1,001,335)	$ 755,604
8	1955	Communications Equipment	$ 51,953,916	$ 1,175,493	$ -	$ 53,129,409	($ 24,154,978)	($ 4,104,648)	$ -	($ 28,259,626)	$ 24,869,783
8	1960	Miscellaneous Equipment	$ 270,978	$ -	$ -	$ 270,978	($ 257,284)	($ 12,066)	$ -	($ 269,350)	$ 1,628
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 70,263,279	$ 9,053,902	($ 668,673)	$ 78,648,509	($ 18,116,791)	($ 4,074,313)	$ 72,264	($ 22,118,840)	$ 56,529,668
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 380,951,077)	($ 80,356,037)	$ 579,154	($ 460,727,959)	$ 30,823,265	$ 11,560,942	($ 29,523)	$ 42,354,685	($ 418,373,275)
N/A	1609	Capital Contributions Paid	$ 220,254,219	$ 2,035,515	$ -	$ 222,289,734	($ 26,252,400)	($ 8,846,852)	$ -	($ 35,099,252)	$ 187,190,482
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 12,999,508)	($ 622,309)	$ -	($ 13,621,817)	$ 6,125,897
		Sub-Total	**$ 5,865,795,633**	**$ 477,964,027**	**($ 30,994,864)**	**$ 6,312,764,796**	**($ 1,336,564,821)**	**($ 257,612,183)**	**$ 3,989,305**	**($ 1,590,187,699)**	**$ 4,722,577,097**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 8,558,725)	($ 868,193)	$ -	($ 9,426,917)	$ 444,856	$ 642,823	$ -	$ 1,087,679	($ 8,339,239)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 15,918,797)	($ 2,121,225)	$ -	($ 18,040,021)	$ 838,735	$ 681,314	$ -	$ 1,520,049	($ 16,519,972)
		Total PP&E	**$ 5,841,318,111**	**$ 474,974,610**	**($ 30,994,864)**	**$ 6,285,297,857**	**($ 1,335,281,230)**	**($ 256,288,046)**	**$ 3,989,305**	**($ 1,587,579,972)**	**$ 4,697,717,886**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 256,288,046)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 254,528,526)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2022**

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 326,583,055	$ 64,227,955	$ -	$ 390,811,010	($ 193,101,734)	($ 38,545,659)	$ -	($ 231,647,393)	$ 159,163,617
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 155,203,541	$ 40,378,055	$ -	$ 195,581,596	($ 23,880,514)	($ 4,350,846)	$ -	($ 28,231,360)	$ 167,350,236
47	1815	Transformer Station Equipment >50 kV	$ 39,156,416	$ 2,478,930	$ -	$ 41,635,346	($ 7,318,304)	($ 1,500,080)	$ -	($ 8,818,385)	$ 32,816,961
47	1820	Distribution Station Equipment <50 kV	$ 291,168,937	$ 26,685,246	($ 343,626)	$ 317,510,557	($ 69,147,402)	($ 12,489,301)	$ 100,860	($ 81,535,843)	$ 235,974,715
47	1830	Poles, Towers & Fixtures	$ 466,745,633	$ 34,588,526	($ 7,317,218)	$ 494,016,941	($ 79,373,607)	($ 13,442,357)	$ 974,920	($ 91,841,044)	$ 402,175,898
47	1835	Overhead Conductors & Devices	$ 575,321,332	$ 45,968,668	($ 2,789,199)	$ 618,500,800	($ 80,526,814)	($ 14,801,768)	$ 299,349	($ 95,029,233)	$ 523,471,567
47	1840	Underground Conduit	$ 1,558,760,795	$ 113,105,155	($ 706,308)	$ 1,671,159,642	($ 354,389,647)	($ 59,758,370)	$ 102,918	($ 414,045,100)	$ 1,257,114,542
47	1845	Underground Conductors & Devices	$ 1,173,204,545	$ 106,870,549	($ 6,276,298)	$ 1,273,798,796	($ 188,897,480)	($ 34,769,524)	$ 594,725	($ 223,072,279)	$ 1,050,726,517
47	1850	Line Transformers	$ 804,626,678	$ 84,455,268	($ 11,655,663)	$ 877,426,283	($ 177,275,379)	($ 31,704,069)	$ 1,629,292	($ 207,350,155)	$ 670,076,128
47	1855	Services (Overhead & Underground)	$ 186,349,135	$ 20,353,222	($ 424,454)	$ 206,277,904	($ 21,647,064)	($ 4,028,117)	$ 24,486	($ 25,650,695)	$ 180,627,208
47	1860	Meters	$ 144,841,193	$ 17,241,110	($ 1,003,870)	$ 161,078,433	($ 32,398,717)	($ 5,981,254)	$ 138,121	($ 38,241,850)	$ 122,836,582
47	1860	Meters (Smart Meters)	$ 157,663,900	$ 8,335,515	($ 260,287)	$ 165,739,128	($ 84,885,874)	($ 10,058,951)	$ 59,557	($ 94,885,267)	$ 70,853,861
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 248,034,869	$ 21,654,357	$ -	$ 269,689,225	($ 71,649,644)	($ 11,520,627)	$ -	($ 83,170,271)	$ 186,518,954
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 23,094,695	$ 7,762,883	$ -	$ 30,857,577	($ 14,822,855)	($ 1,470,022)	$ -	($ 16,292,877)	$ 14,564,701
50	1920	Computer Equipment - Hardware	$ 100,225,137	$ 13,269,836	$ -	$ 113,494,973	($ 73,271,562)	($ 10,950,953)	$ -	($ 84,222,515)	$ 29,272,458
10	1930	Transportation Equipment	$ 54,000,688	$ 7,924,120	$ -	$ 61,924,808	($ 34,576,011)	($ 4,417,573)	$ -	($ 38,993,584)	$ 22,931,223
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 63,705,645	$ 28,985,036	$ -	$ 92,690,682	($ 20,739,115)	($ 5,447,891)	$ -	($ 26,187,006)	$ 66,503,675
8	1945	Measurement & Testing Equipment	$ 814,449	$ 11,671	$ -	$ 826,120	($ 486,700)	($ 36,843)	$ -	($ 523,544)	$ 302,577
8	1950	Service Equipment	$ 1,756,939	$ 236,128	$ -	$ 1,993,067	($ 1,001,335)	($ 153,730)	$ -	($ 1,155,065)	$ 838,002
8	1955	Communications Equipment	$ 53,129,409	$ 1,180,207	$ -	$ 54,309,616	($ 28,259,626)	($ 3,324,294)	$ -	($ 31,583,920)	$ 22,725,696
8	1960	Miscellaneous Equipment	$ 270,978	$ 1,579,433	$ -	$ 1,850,410	($ 269,350)	($ 19,256)	$ -	($ 288,606)	$ 1,561,804
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 78,648,509	$ 11,646,178	($ 667,846)	$ 89,626,840	($ 22,118,840)	($ 4,298,811)	$ 72,176	($ 26,345,476)	$ 63,281,364
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 460,727,959)	($ 71,719,865)	$ 597,344	($ 531,850,480)	$ 42,354,685	$ 13,732,602	($ 30,450)	$ 56,056,837	($ 475,793,643)
N/A	1609	Capital Contributions Paid	$ 222,289,734	$ 4,143,670	$ -	$ 226,433,404	($ 35,099,252)	($ 8,973,950)	$ -	($ 44,073,202)	$ 182,360,202
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 13,621,817)	($ 359,675)	$ -	($ 13,981,493)	$ 5,766,222
		Sub-Total	**$ 6,312,764,796**	**$ 591,361,853**	**($ 30,847,427)**	**$ 6,873,279,222**	**($ 1,590,187,699)**	**($ 268,671,321)**	**$ 3,965,954**	**($ 1,854,893,067)**	**$ 5,018,386,156**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 9,426,917)	($ 1,694,024)	$ -	($ 11,120,941)	$ 1,087,679	$ 748,002	$ -	$ 1,835,680	($ 9,285,261)
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*	($ 18,040,021)	($ 2,219,756)	$ -	($ 20,259,777)	$ 1,520,049	$ 760,391	$ -	$ 2,280,440	($ 17,979,338)
		Total PP&E	**$ 6,285,297,857**	**$ 587,448,073**	**($ 30,847,427)**	**$ 6,841,898,504**	**($ 1,587,579,972)**	**($ 267,162,929)**	**$ 3,965,954**	**($ 1,850,776,947)**	**$ 4,991,121,557**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 267,162,929)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 265,403,409)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2023

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 390,811,010	$ 41,755,588	$ -	$ 432,566,598	($ 231,647,393)	($ 43,244,819)	$ -	($ 274,892,212)	$ 157,674,386
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 195,581,596	$ 27,700,557	$ -	$ 223,282,152	($ 28,231,360)	($ 6,059,192)	$ -	($ 34,290,551)	$ 188,991,601
47	1815	Transformer Station Equipment >50 kV	$ 41,635,346	$ 2,961,227	$ -	$ 44,596,573	($ 8,818,385)	($ 1,632,624)	$ -	($ 10,451,009)	$ 34,145,564
47	1820	Distribution Station Equipment <50 kV	$ 317,510,557	$ 26,897,223	($ 358,450)	$ 344,049,330	($ 81,535,843)	($ 13,455,228)	$ 105,205	($ 94,885,865)	$ 249,163,465
47	1830	Poles, Towers & Fixtures	$ 494,016,941	$ 35,925,013	($ 7,769,068)	$ 522,172,887	($ 91,841,044)	($ 14,251,511)	$ 1,020,341	($ 105,072,213)	$ 417,100,674
47	1835	Overhead Conductors & Devices	$ 618,500,800	$ 46,856,177	($ 2,959,674)	$ 662,397,303	($ 95,029,233)	($ 15,757,264)	$ 314,872	($ 110,471,625)	$ 551,925,678
47	1840	Underground Conduit	$ 1,671,159,642	$ 118,101,839	($ 744,311)	$ 1,788,517,171	($ 414,045,100)	($ 63,572,653)	$ 107,359	($ 477,510,394)	$ 1,311,006,776
47	1845	Underground Conductors & Devices	$ 1,273,798,796	$ 113,798,427	($ 6,689,225)	$ 1,380,907,998	($ 223,072,279)	($ 36,897,119)	$ 632,475	($ 259,336,923)	$ 1,121,571,075
47	1850	Line Transformers	$ 877,426,283	$ 88,264,338	($ 12,233,907)	$ 953,456,714	($ 207,350,155)	($ 33,692,007)	$ 1,708,443	($ 239,333,719)	$ 714,122,994
47	1855	Services (Overhead & Underground)	$ 206,277,904	$ 20,992,446	($ 454,636)	$ 226,815,713	($ 25,650,695)	($ 4,354,613)	$ 26,227	($ 29,979,081)	$ 196,836,632
47	1860	Meters	$ 161,078,433	$ 21,145,521	($ 981,543)	$ 181,242,411	($ 38,241,850)	($ 6,372,346)	$ 135,049	($ 44,479,147)	$ 136,763,264
47	1860	Meters (Smart Meters)	$ 165,739,128	$ 9,702,716	($ 116,284)	$ 175,325,560	($ 94,885,267)	($ 8,742,141)	$ 26,487	($ 103,600,921)	$ 71,724,639
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 269,689,225	$ 5,387,713	$ -	$ 275,076,939	($ 83,170,271)	($ 12,342,070)	$ -	($ 95,512,341)	$ 179,564,597
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 30,857,577	$ 1,931,444	$ -	$ 32,789,022	($ 16,292,877)	($ 1,898,451)	$ -	($ 18,191,327)	$ 14,597,694
50	1920	Computer Equipment - Hardware	$ 113,494,973	$ 14,016,313	$ -	$ 127,511,286	($ 84,222,515)	($ 12,737,643)	$ -	($ 96,960,158)	$ 30,551,128
10	1930	Transportation Equipment	$ 61,924,808	$ 8,503,841	$ -	$ 70,428,649	($ 38,993,584)	($ 5,306,497)	$ -	($ 44,300,082)	$ 26,128,567
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 92,690,682	$ 2,176,390	$ -	$ 94,867,071	($ 26,187,006)	($ 6,268,652)	$ -	($ 32,455,658)	$ 62,411,413
8	1945	Measurement & Testing Equipment	$ 826,120	$ 235	$ -	$ 826,355	($ 523,544)	($ 21,944)	$ -	($ 545,488)	$ 280,868
8	1950	Service Equipment	$ 1,993,067	$ 254,014	$ -	$ 2,247,081	($ 1,155,065)	($ 184,485)	$ -	($ 1,339,550)	$ 907,531
8	1955	Communications Equipment	$ 54,309,616	$ 1,403,601	$ -	$ 55,713,218	($ 31,583,920)	($ 2,803,611)	$ -	($ 34,387,531)	$ 21,325,686
8	1960	Miscellaneous Equipment	$ 1,850,410	$ -	$ -	$ 1,850,410	($ 288,606)	($ 226,779)	$ -	($ 515,385)	$ 1,335,026
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 89,626,840	$ 12,487,400	($ 712,351)	$ 101,401,890	($ 26,345,476)	($ 4,485,953)	$ 76,983	($ 30,754,445)	$ 70,647,444
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 531,850,480)	($ 46,370,896)	$ 643,931	($ 577,577,445)	$ 56,056,837	$ 15,226,060	($ 32,825)	$ 71,250,072	($ 506,327,373)
N/A	1609	Capital Contributions Paid	$ 226,433,404	$ 38,957,642	$ -	$ 265,391,046	($ 44,073,202)	($ 9,893,999)	$ -	($ 53,967,201)	$ 211,423,845
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 13,981,493)	($ 128,056)	$ -	($ 14,109,548)	$ 5,638,166
		Sub-Total	**$ 6,873,279,222**	**$ 592,848,770**	**($ 32,375,518)**	**$ 7,433,752,475**	**($ 1,854,893,067)**	**($ 289,103,595)**	**$ 4,120,617**	**($ 2,139,876,045)**	**$ 5,293,876,430**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 11,120,941)	$ -	$ -	($ 11,120,941)	$ 1,835,680	$ 741,396	$ -	$ 2,577,076	($ 8,543,865)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 20,259,777)	($ 2,364,569)	$ -	($ 22,624,347)	$ 2,280,440	$ 843,961	$ -	$ 3,124,401	($ 19,499,946)
		Total PP&E	**$ 6,841,898,504**	**$ 590,484,201**	**($ 32,375,518)**	**$ 7,400,007,188**	**($ 1,850,776,947)**	**($ 287,518,238)**	**$ 4,120,617**	**($ 2,134,174,568)**	**$ 5,265,832,620**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 287,518,238)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 285,758,717)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2024

			Cost (Forecast)				Accumulated Depreciation (Forecast)				
CCA Class	**OEB Account**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 432,566,598	$ 42,093,911	$ -	$ 474,660,509	($ 274,892,212)	($ 43,235,561)	$ -	($ 318,127,773)	$ 156,532,736
N/A	1612	Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 7,006,432	$ -	$ -	$ 7,006,432	$ -	$ -	$ -	$ -	$ 7,006,432
1	1808	Buildings	$ 223,282,152	$ 29,868,364	$ -	$ 253,150,517	($ 34,290,551)	($ 7,004,320)	$ -	($ 41,294,871)	$ 211,855,646
47	1815	Transformer Station Equipment >50 kV	$ 44,596,573	$ 3,245,603	$ -	$ 47,842,175	($ 10,451,009)	($ 1,770,382)	$ -	($ 12,221,391)	$ 35,620,785
47	1820	Distribution Station Equipment <50 kV	$ 344,049,330	$ 36,813,051	($ 363,939)	$ 380,498,442	($ 94,885,865)	($ 14,380,354)	$ 106,818	($ 109,159,401)	$ 271,339,041
47	1830	Poles, Towers & Fixtures	$ 522,172,887	$ 50,051,715	($ 7,846,443)	$ 564,378,159	($ 105,072,213)	($ 15,197,585)	$ 1,028,747	($ 119,241,051)	$ 445,137,108
47	1835	Overhead Conductors & Devices	$ 662,397,303	$ 68,451,053	($ 2,991,329)	$ 727,857,027	($ 110,471,625)	($ 17,021,092)	$ 317,902	($ 127,174,815)	$ 600,682,212
47	1840	Underground Conduit	$ 1,788,517,171	$ 162,531,104	($ 753,024)	$ 1,950,295,251	($ 477,510,394)	($ 67,613,566)	$ 108,392	($ 545,015,568)	$ 1,405,279,683
47	1845	Underground Conductors & Devices	$ 1,380,907,998	$ 156,176,233	($ 6,757,459)	$ 1,530,326,772	($ 259,336,923)	($ 39,575,168)	$ 639,251	($ 298,272,840)	$ 1,232,053,932
47	1850	Line Transformers	$ 953,456,714	$ 123,778,708	($ 12,403,105)	$ 1,064,832,316	($ 239,333,719)	($ 35,404,488)	$ 1,732,472	($ 273,005,735)	$ 791,826,581
47	1855	Services (Overhead & Underground)	$ 226,815,713	$ 28,096,699	($ 458,743)	$ 254,453,669	($ 29,979,081)	($ 4,733,044)	$ 26,464	($ 34,685,660)	$ 219,768,008
47	1860	Meters	$ 181,242,411	$ 34,217,845	($ 950,656)	$ 214,509,600	($ 44,479,147)	($ 6,838,786)	$ 130,800	($ 51,187,133)	$ 163,322,467
47	1860	Meters (Smart Meters)	$ 175,325,560	$ 15,285,136	($ 13,248)	$ 190,597,448	($ 103,600,921)	($ 7,807,576)	$ 2,855	($ 111,405,642)	$ 79,191,806
N/A	1905	Land	$ 17,358,657	$ -	$ -	$ 17,358,657	$ -	$ -	$ -	$ -	$ 17,358,657
1	1908	Buildings & Fixtures	$ 275,076,939	$ 5,669,199	$ -	$ 280,746,138	($ 95,512,341)	($ 10,414,223)	$ -	($ 105,926,564)	$ 174,819,574
13	1910	Leasehold Improvements	$ 753,840	$ -	$ -	$ 753,840	($ 753,840)	$ -	$ -	($ 753,840)	$ -
8	1915	Office Furniture & Equipment	$ 32,789,022	$ 2,032,354	$ -	$ 34,821,376	($ 18,191,327)	($ 2,050,626)	$ -	($ 20,241,953)	$ 14,579,423
50	1920	Computer Equipment - Hardware	$ 127,511,286	$ 14,933,709	$ -	$ 142,444,996	($ 96,960,158)	($ 13,959,747)	$ -	($ 110,919,906)	$ 31,525,090
10	1930	Transportation Equipment	$ 70,428,649	$ 8,817,216	$ -	$ 79,245,865	($ 44,300,082)	($ 6,247,699)	$ -	($ 50,547,780)	$ 28,698,084
8	1935	Stores Equipment	$ 7,066	$ -	$ -	$ 7,066	($ 7,066)	$ -	$ -	($ 7,066)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 94,867,071	$ 3,125,886	$ -	$ 97,992,957	($ 32,455,658)	($ 6,231,724)	$ -	($ 38,687,383)	$ 59,305,575
8	1945	Measurement & Testing Equipment	$ 826,355	$ 399	$ -	$ 826,755	($ 545,488)	($ 21,945)	$ -	($ 567,432)	$ 259,323
8	1950	Service Equipment	$ 2,247,081	$ 263,573	$ -	$ 2,510,654	($ 1,339,550)	($ 217,825)	$ -	($ 1,557,375)	$ 953,278
8	1955	Communications Equipment	$ 55,713,218	$ 1,770,353	$ -	$ 57,483,571	($ 34,387,531)	($ 2,723,621)	$ -	($ 37,111,152)	$ 20,372,418
8	1960	Miscellaneous Equipment	$ 1,850,410	$ -	$ -	$ 1,850,410	($ 515,385)	($ 226,779)	$ -	($ 742,163)	$ 1,108,247
47	1970	Load Management Controls Customer Premises	$ 3,022,834	$ -	$ -	$ 3,022,834	($ 3,022,834)	$ -	$ -	($ 3,022,834)	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 101,401,890	$ 15,855,126	($ 719,484)	$ 116,537,532	($ 30,754,445)	($ 4,930,266)	$ 77,754	($ 35,606,958)	$ 80,930,575
47	2440	Contributions & Grants (Formally known as Account 1995)	($ 577,577,445)	($ 226,921,734)	$ 648,701	($ 803,850,479)	$ 71,250,072	$ 16,468,884	($ 33,068)	$ 87,685,888	($ 716,164,590)
N/A	1609	Capital Contributions Paid	$ 265,391,046	$ 9,979,192	$ -	$ 275,370,239	($ 53,967,201)	($ 10,824,439)	$ -	($ 64,791,640)	$ 210,578,599
N/A	2005	Property Under Capital Leases	$ 19,747,714	$ -	$ -	$ 19,747,714	($ 14,109,548)	($ 128,056)	$ -	($ 14,237,604)	$ 5,510,110
		Sub-Total	**$ 7,433,752,475**	**$ 586,134,696**	**($ 32,608,729)**	**$ 7,987,278,441**	**($ 2,139,876,045)**	**($ 302,089,985)**	**$ 4,138,387**	**($ 2,437,827,643)**	**$ 5,549,450,798**
		Less Socialized Renewable Energy Generation Investments (input as negative)	($ 11,120,941)	$ -	$ -	($ 11,120,941)	$ 2,577,076	$ 741,396	$ -	$ 3,318,472	($ 7,802,469)
		Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 22,624,347)	($ 2,515,682)	$ -	($ 25,140,029)	$ 3,124,401	$ 932,922	$ -	$ 4,057,323	($ 21,082,705)
		Total PP&E	**$ 7,400,007,188**	**$ 583,619,014**	**($ 32,608,729)**	**$ 7,951,017,472**	**($ 2,134,174,568)**	**($ 300,415,667)**	**$ 4,138,387**	**($ 2,430,451,848)**	**$ 5,520,565,624**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)						$ -			
		Total						**($ 300,415,667)**			

10		Transportation
		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,759,521)
Stores Equipment	$ -
Net Depreciation	($ 298,656,146)

Notes:
Fixed Asset Continuity Schedule includes monthly billing
Socialized Renewable Energy Generation Investments include Energy Storage program
Other Non Rate-Regulated Utility Assets includes Generation Protection, Monitoring and Control program

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 4, Table 3

Table 1: Gross and Net PP&E – Years Ending December 31 ($ Millions)

	2015 Actual	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Bridge**	**2020 Forecast**
Land and Buildings	76.2	129.9	141.4	161.6	171.0	174.5
Other Distribution Assets	170.0	238.5	267.3	434.6	507.6	586.9
General Plant	127.7	185.2	247.5	240.1	241.4	244.3
TS Primary Above 50	5.8	6.0	36.9	37.9	38.9	39.0
Distribution System	149.9	156.8	184.5	213.5	233.9	266.4
Poles, Wires	2,172.2	2,430.6	2,663.8	2,876.9	3,132.8	3,486.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(381.0)
Line Transformers	412.4	465.3	515.4	566.7	640.8	731.9
Services and Meters	262.0	290.0	321.8	344.7	385.3	445.8
Equipment	61.5	100.4	120.8	131.3	140.5	157.2
IT Assets	27.3	47.2	58.7	66.8	74.2	89.3
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,841.3**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(876.9)	(1,097.7)	(1,335.3)
Closing PP&E NBV	**3,086.2**	**3,462.6**	**3,755.8**	**4,040.6**	**4,233.4**	**4,506.0**
Adjustments to Closing PP&E NBV						
Assets held for Sale	-	-	(8.7)	-	-	-
Monthly Billing	(0.7)	(0.6)	(2.3)	(1.7)	(1.1)	-
Closing PP&E NBV	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,506.0**

Note: Variances due to rounding may exist

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 7, Table 6

Table 2: 2019 Bridge versus 2020 Forecast ($ Millions)

	2019 Bridge	2020 Forecast	Variance ($)	Variance (%)
Land and Buildings	171.0	174.5	3.5	2.1%
Other Distribution Assets	507.6	586.9	79.4	15.6%
General Plant	241.4	244.3	2.9	1.2%
TS Primary Above 50	38.9	39.0	0.1	0.4%
Distribution System	233.9	266.4	32.5	13.9%
Poles, Wires	3,132.8	3,486.9	354.1	11.3%
Contributions and Grants	(235.2)	(381.0)	(145.7)	61.9%
Line Transformers	640.8	731.9	91.1	14.2%
Services and Meters	385.3	445.8	60.5	15.7%
Equipment	140.5	157.2	16.7	11.9%
IT Assets	74.2	89.3	15.1	20.4%
Gross Assets	**5,331.0**	**5,841.3**	**510.3**	**9.6%**
Accumulated Depreciation	(1,097.7)	(1,335.3)	(237.6)	21.6%
Closing PP&E NBV (MIFRS)	**4,233.4**	**4,506.0**	**272.6**	**6.4%**

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 8, Table 7

Table 3: Breakdown of Ending Balance of Gross Assets by Function ($ Millions)

Gross Assets	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.0
Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,984.8
General Plant	354.0	482.3	599.8	683.2	741.1	817.4
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,841.3**
CWIP	577.7	502.9	485.8	396.4	381.1	358.3
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,313.9**	**5,712.2**	**6,162.1**

Note: Variances due to rounding may exist

Original Reference: Exhibit U, Tab 2, Schedule 1, Appendix C

Table 4: Gross Assets Breakdown by Major Plant Account – Detailed by Uniform System of Account

	Description	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Bridge MIFRS	2020 Forecast MIFRS
1815	Transformer Station Equipment	5.8	6.0	36.9	37.9	38.9	39.0
	Subtotal High Voltage Plant	5.8	6.0	36.9	37.9	38.9	39.0
1805	Land	7.1	7.1	7.0	7.0	7.0	7.0
1808	Buildings and Fixtures	51.4	105.1	116.6	137.3	146.6	150.1
1810	Leasehold Improvements	-	-	-	-	-	-
1820	Distribution Station Equipment	149.9	156.8	184.5	213.5	233.9	266.4
1830	Poles, Towers and Fixtures	311.0	339.5	362.5	380.8	402.6	438.4
1835	O/H Conductors and Devices	299.4	349.5	390.5	428.3	468.2	527.1
1840	U/G Conduit	952.0	1,051.0	1,127.9	1,205.6	1,306.1	1,446.6
1845	U/G Conductors and Devices	609.9	690.6	782.8	862.2	955.9	1,074.8
1850	Line Transformers	412.4	465.3	515.4	566.7	640.8	731.9
1855	Services	93.3	109.1	122.1	124.6	141.4	166.1
1860	Meters (includes Smart Meters)	168.7	180.9	199.7	220.1	243.9	279.8
1970	Load Management-Customer	3.0	3.0	3.0	3.0	3.0	3.0
1975	Load Management-Utility	-	-	-	-	-	-
1980	System Supervisory Equipment	25.4	28.2	33.6	39.7	46.4	54.3
1609	Capital Contributions Paid	21.7	75.6	75.6	164.2	190.5	220.3
2440	Contributed Capital	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(381.0)
	Subtotal Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,984.8
1611	Computer Software	101.6	113.6	137.0	207.9	247.9	289.5
1905	Land	17.7	17.7	17.7	17.4	17.4	17.4
1612	Land Rights	-	-	-	1.6	1.6	1.6
1908	Buildings and Fixtures	126.9	184.5	246.7	239.4	240.6	243.6
1910	Leasehold Improvements	0.8	0.8	0.8	0.8	0.8	0.8
1915	Office Furniture and Equipment	10.8	15.4	19.0	20.0	20.4	21.5
1920	Computer Equipment	27.3	47.2	58.7	66.8	74.2	89.3
1930	Transportation Equipment	26.6	29.9	33.7	36.1	41.1	45.7
1935	Stores Equipment	0.0	0.0	0.0	0.0	0.0	0.0
1940	Tools, Shop and Garage Equipment	14.7	17.8	21.2	23.4	26.2	35.7
1945	Measurement & Test Equipment	0.5	0.5	0.5	0.5	0.5	0.6
1950	Power Operated Equipment	0.6	0.7	0.8	1.3	1.4	1.5
1955	Communication Equipment	8.0	35.9	45.4	49.9	50.7	52.0
1960	Miscellaneous Equipment	0.3	0.3	0.3	0.3	0.3	0.3
2005	Property Under Capital Leases	18.2	18.2	18.2	18.2	18.2	18.2
	Subtotal General Plant	354.0	482.3	599.8	683.2	741.1	817.4
	GROSS FIXED ASSETS BEFORE CWIP	3,406.8	3,959.4	4,440.1	4,917.5	5,331.0	5,841.3
2055	Construction Work-in-Process	577.7	502.9	485.8	396.4	381.1	358.3
	TOTAL INCLUDING CWIP	3,984.5	4,462.3	4,925.9	5,313.9	5,712.2	6,199.6

Original Reference: Exhibit U, Tab 4B, Schedule 1, Appendix A

Table 5: Summary of Depreciation Expense

OEB	Description	2020 MIFRS Depreciation Expense	2020 MIFRS Derecognition	2020 MIFRS Total Depreciation Expense
1611	Computer Software (Formally known as Account 1925)	$ 32,653,777	$ -	$ 32,653,777
1612	Land Rights	$ -	$ -	$ -
1805	Land	$ -	$ -	$ -
1808	Buildings	$ 3,719,188	$ -	$ 3,719,188
1815	Transformer Station Equipment >50 kV	$ 1,387,410	$ -	$ 1,387,410
1820	Distribution Station Equipment <50 kV	$ 10,856,456	$ 230,873	$ 11,087,329
1830	Poles, Towers & Fixtures	$ 11,871,898	$ 5,970,306	$ 17,842,204
1835	Overhead Conductors & Devices	$ 12,475,862	$ 2,345,789	$ 14,821,651
1840	Underground Conduit	$ 51,782,108	$ 570,460	$ 52,352,569
1845	Underground Conductors & Devices	$ 29,865,268	$ 5,343,042	$ 35,208,310
1850	Line Transformers	$ 27,962,577	$ 9,503,228	$ 37,465,805
1855	Services (Overhead & Underground)	$ 3,358,705	$ 375,123	$ 3,733,828
1860	Meters	$ 17,453,270	$ 1,431,703	$ 18,884,973
1905	Land	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,356,784	$ -	$ 11,356,784
1910	Leasehold Improvements	$ -	$ -	$ -
1915	Office Furniture & Equipment	$ 1,886,440	$ -	$ 1,886,440
1920	Computer Equipment - Hardware	$ 11,199,443	$ -	$ 11,199,443
1930	Transportation Equipment	$ 3,150,222	$ -	$ 3,150,222
1935	Stores Equipment	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 3,017,290	$ -	$ 3,017,290
1945	Measurement & Testing Equipment	$ 50,414	$ -	$ 50,414
1950	Power Operated Equipment	$ 127,564	$ -	$ 127,564
1955	Communications Equipment	$ 4,395,505	$ -	$ 4,395,505
1960	Miscellaneous Equipment	$ 34,271	$ -	$ 34,271
1970	Load Management Controls Customer Premises	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 3,652,397	$ 560,039	$ 4,212,436
2440	Contributions & Grants	($ 8,804,137)	($ 537,050)	($ 9,341,186)
1609	Capital Contributions Paid	$ 8,256,701	$ -	$ 8,256,701
2005	Property Under Capital Leases	$ 676,393	$ -	$ 676,393
	Sub-Total	$ 242,385,809	$ 25,793,513	$ 268,179,322
	Less Socialized Renewable Energy Generation Investments (input as negative)	($ 410,729)	$ -	($ 410,729)
	Less Other Non Rate-Regulated Utility Assets (input as negative)	($ 469,291)	$ -	($ 469,291)
	Total	$ 241,505,789	$ 25,793,513	$ 267,299,302
	Less: Fully Allocated Depreciation Transportation	($ 1,759,521)		($ 1,759,521)
	Net Depreciation	**$ 239,746,268**	**$ 25,793,513**	**$ 265,539,781**

Original Reference: Exhibit U, Tab 4B, Schedule 1, Page 2, Table 3

Table 6: Depreciation and Amortization Expense 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Updated Bridge	2020 Updated Forecast
Depreciation and Amortization Expense	166.0	179.1	192.5	205.3	223.6	239.7

Original Reference: Exhibit U, Tab 2, Schedule 2, Appendix B

Table 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	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	86.1	58.3	-32.3%	95.3	79.0	-17.2%	104.9	65.5	-37.6%	95.8	88.0	-8.1%	92.3	112.1	21.4%	92.8	93.3	93.9	106.0	116.4
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	307.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	34.6	60.1	71.3	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	79.6	93.7	89.0	77.7	85.2
Other	12.2	11.6	-4.8%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	12.7	10.5%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	521.6	581.8	587.1	565.7	574.4
Capital Contributions Paid	(6.6)	(4.0)	-40.0%	(29.1)	(16.6)	-42.9%	(48.2)	(37.4)	-22.5%	(32.1)	(12.4)	-61.2%	(30.5)	(18.5)	-39.4%	(12.8)	(16.1)	(15.2)	(16.8)	(14.6)
Net Capital Expenditures	524.5	487.5	-7.1%	489.7	495.0	1.1%	419.2	460.5	9.9%	438.0	423.2	-3.4%	471.6	424.5	-10.0%	508.8	565.7	571.9	548.9	559.8
System O&M	128.8	116.1	-9.9%		126.5	--		126.3	--		139.6	--		131.0	--	130.4				

Note: Variances due to rounding may exist

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Refer to respective category sections for discussion on historical vs forecast shifts. Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Original Reference: Exhibit U, Tab 2, Schedule 2, Appendix C

Table 8:
OEB Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period:

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	103.3	97.4	-5.8%	112.8	113.0	0.2%	122.0	113.0	-7.4%	113.8	153.0	34.4%	111.9	236.0	110.9%	161.4	189.6	181.3	193.8	207.2
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	307.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	58.9	72.2	77.1	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	79.6	93.7	89.0	77.7	85.2
Other	12.2	13.5	10.9%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	13.0	13.2%	12.1	(1.3)	-111.1%	7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE	548.3	532.3	-2.9%	536.2	545.6	1.8%	484.5	545.3	12.5%	488.0	500.9	2.6%	521.7	566.9	8.7%	614.5	690.2	680.4	653.6	665.2
Capital Contributions Received	(17.2)	(40.9)	138.1%	(17.4)	(34.0)	95.3%	(17.1)	(47.5)	177.1%	(18.0)	(65.3)	262.7%	(19.6)	(123.9)	533.0%	(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	521.6	581.8	587.1	565.7	574.4
System O&M	128.8	116.1	-9.9%		126.5			126.3			139.6			131.0		130.4				

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Refer to respective category sections for discussion on historical vs forecast shifts. Section E5 for System Access, Section E6 for System Renewal, Section E7 for System Service and Section E8 for General Plant.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Refer to Section E4 on Variance analysis for between Plan vs Actuals.

Original Reference: Exhibit U, Tab 2, Schedule 1, Page 2, Table 2

Table 9: Historical, Bridge and Forecasted Construction Work In Progress ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Opening CWIP	522.1	577.7	502.9	485.8	396.4	381.1
Additions (CAPEX)	490.6	508.4	496.6	434.9	425.3	517.2
Deductions (In Service Additions)	(435.3)	(584.3)	(520.3)	(524.4)	(440.6)	(539.9)
Other	0.3	1.1	6.5	0.0	-	-
Closing CWIP	577.7	502.9	485.8	396.4	381.1	358.3

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 169:

Reference(s): Exhibit U, Tab 2, Schedule 1, p. 9

Preamble:

Toronto Hydro proposes to update its 2020 working capital allowance (WCA) during the draft rate order process of this proceeding. Toronto Hydro stated part of the change to the WCA is due to the OEB's revised Customer Service Rules (extension of bill payment dates). Toronto Hydro estimated the revenue requirement impact of this aspect of the WCA change to be a $1.6 million increase (offset by a $2.2 million revenue requirement decrease related to the approach used to calculate cost of power).

a) Please provide further details regarding the impact of the OEB's revised Customer Service Rules on the collection lag component of Toronto Hydro's Lead / Lag study.

b) Please provide the calculation supporting the $1.6 million revenue requirement impact of this change to the WCA.

RESPONSE:

a) Toronto Hydro requested Navigant to provide an estimate of the impact on the Lead/Lag results due to the extension of customer payments, allowing for a 20 day payment period compared to the current 16 day payment period. The extension of customer payments is anticipated to impact the collections lag which is a component of revenue lag. The scenario estimating the impact for an increase of 4 days in the payment period produced a 2.3 day increase in collections lag.

The increase in collections lag of 2.3 days is less than the full extension period of 4 days due to the adjustment impacting only a subset of retail revenue. Specifically, the extension period would likely have no impact on customers that pay after 20 days (approximately 18 percent of retail revenue) and the extension period would likely have no impact on customers that have opted for pre-authorized payment (approximately 25 percent of customers).

b) The table in Appendix A shows the inputs into the original WCA calculation and the updated inputs based on Navigant’s estimate.

Appendix A - Working Capital Allowance - Extension of Customer Payments

	Prefile						Additional Payment Days					
Working Capital Allowance	Revenue Lag Days	Expense Lead Days	Net Lag Days	Prefile Working Capital Factors (a)	Expense (Millions) (b)	Prefiled Working Req Allowance (Millions) (a x b)	Revenue Lag Days	Expense Lead Days	Net Lag Days	Upated Working Capital Factors (a)	Expense (Millions) (b)	Updated Working Req Allowance (Millions) (a x b)
- Cost of Power	50.87	32.63	18.24	5.00%	$3,384.0	$169.2	53.17	32.63	20.54	5.61%	$3,384.0	$189.8
- EXPENSES												
- OM&A Expense	50.87	35.19	15.68	4.29%	$277.5	$11.9	53.17	35.19	17.98	4.91%	$277.5	$13.6
- Interest on Long term debt	50.87	25.34	25.52	6.99%	$89.2	$6.2	53.17	25.34	27.82	7.60%	$89.2	$6.8
- Income, and Capital Tax	50.87	-10.05	60.91	16.69%	$34.7	$5.8	53.17	-10.05	63.21	17.27%	$34.7	$6.0
- HST						$42.1						$42.1
Working Capital						**$235.2**						**$258.3**
Difference from Prefiled												**$23.1**
Cost of Capital rate												**5.70%**
Return on Rate Base												**$1.3**
PILS @ 26.5%												**$0.3**
Revenue Requirement Impact												**$1.6**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 170:

Reference(s): **Exhibit U, Tab 2, Schedule 1, p. 2 and Appendix A**
2B-Staff-75, part (a) (ii)

<u>Preamble:</u>

Toronto Hydro projects its net total five-year ISAs to be approximately 1% greater than the forecast amount, which formed the basis of its approved capital-related revenue requirement for the 2015-2019 period.

Toronto Hydro provided an updated 2B-Staff-75 / part (a) (ii) as Appendix A to Exhibit U / Tab 2 / Schedule 1.

a) Please confirm that the 1% figure referenced in the preamble is in relation to the OEB-approved ISAs (as opposed to the planned amounts set out in the 2015-2019 Custom IR application[1]).

b) Please provide a revised Exhibit U / Tab 2 / Schedule 1 / Appendix A that compares the actual / forecast ISAs to the planned ISAs that were proposed in the 2015-2019 Custom IR application for each year (as opposed to the approved amounts).

c) Please further explain the decrease in the 2018 ISAs as between forecast in the originally filed evidence ($608.9 million) and the 2018 actuals ($524.4 million).

[1] EB-2014-0116.

d) Please further explain the increase in the 2019 ISAs as between forecast in the originally filed evidence ($397.8 million) and the updated 2019 forecast ($440.6 million).

RESPONSE:

a) Toronto Hydro confirms that the 1 percent figure referenced in the preamble is in relation to the "OEB-approved" ISAs. Specifically, the figure relates to Toronto Hydro's original 2015-2019 ISA forecast, reduced pursuant to the OEB's Decision in EB-2014-0116. This reduced ISA forecast formed the basis of the OEB-approved capital related revenue requirement for the period.

b) Please refer to Appendix A to this response.

c) Please see Table 1 below presenting the 2018 variance between forecast and actual in-service additions by major categories.

Table 1: 2018 Bridge vs. Actual In-Service Additions ($ Millions)

In-Service Additions	2018 Bridge	2018 Actual	Variance
Distribution Capital Projects	333.5	319.5	(14.0)
Metering Data Collection Systems	5.8	0.0	(5.7)
Streetlighting	4.1	1.9	(2.2)
Hydro One Contributions	66.8	57.6	(9.2)
Facilities and Fleet	10.1	10.6	0.5
ERP	66.6	56.1	(10.5)
Copeland	76.4	50.5	(25.8)
IT Projects	34.2	27.6	(6.6)
External Demand Projects	7.6	0.1	(7.5)
Other	3.9	0.3	(3.6)
Total	**608.9**	**524.4**	**(84.6)**

Note: ISA quoted above includes AFUDC

The largest contributors to lower than forecast 2018 ISAs were (1) in-service delays for two major projects (i.e. ERP and Copeland); (2) lower Hydro One Capital Contributions primarily due to the delay of the planned Horner TS project; and (3) lower than forecast ISAs in various Distribution Capital Projects.

The factors that caused a delay in ISA for Copeland have been further described in Toronto Hydro's response to 2B-Staff-95, part (b). These factors include unusually adverse weather events, challenging site conditions, logistical challenges and contractor performance.

While the ERP successfully went live in 2018, some of the post-go-live system stabilization work carried-over into 2019.

The category Distribution Capital Projects includes several programs in the System Access, System Service, and System Renewal investment categories. Variances in ISAs in this category are typically the result of a number of factors, including project-level scope and cost variances, demand variances (e.g. customer connections demand), schedule changes, emerging system needs (including the diversion of resources to unplanned work), and third-party requirements and constraints. For variance analysis related to the capital expenditures in these programs, please refer to Exhibit U, Tab 2, Schedule 2. The delay of Hydro One Capital Contributions is also discussed in this section.

d) Please see below Table 2 presenting the 2019 variance between the pre-filed and updated 2019 ISA forecast by major categories.

Table 2: 2019 Pre-filed vs. Updated In-Service Additions ($ Millions)

In-Service Additions	2019 Bridge	2019 Updated Bridge	Variance
Distribution Capital Projects	331.5	329.7	(1.9)
Metering Data Collection Systems	3.8	7.0	3.2
Streetlighting	3.8	5.6	1.8
Hydro One Contributions	5.6	4.0	(1.6)
Facilities and Fleet	5.5	7.0	1.5
ERP	-	7.1	7.1
Copeland	-	32.0	32.0
IT Projects	37.9	33.6	(4.3)
External Demand Projects	7.9	12.9	5.0
Other	1.8	1.6	(0.1)
Total	**397.8**	**440.6**	**42.8**

Note: ISA quoted above includes AFUDC

The increase in forecast 2019 ISAs is primarily due to the consequences of the 2018 ISA variances discussed in response to part (c) above. A portion of these ISAs are now forecast for 2019. The most significant carryover amounts include Copeland TS, which primarily consists of the energization of Transformer T1 as described in response to 2B-Staff-95, part (b), and the remaining post go-live work involved in the ERP project. External Demand Projects and Metering Data Collection projects are also expected to have increases in ISAs relating to carryover from 2019. Exhibit U, Tab 2, Schedule 2 has additional information on shifts in capital expenditures between 2018 and 2019.

Some ISAs from the 2018-2019 period have shifted into 2020 as a result of project deferrals. Please refer to Toronto Hydro's response to U-Staff-168 for additional details regarding projects that were planned for the 2018-2019 period, are forecast to be near completion by the end of 2019, and are expected to come into service in 2020.

U-Staff-170 Appendix A

	Historical												Bridge			Historical/Bridge		
	2015			2016			2017			2018			2019			2015-2019		
In-Service Additions	**CIR Filing**	**Actual**	**Var.**	**CIR Filing**	**Actual**	**Var.**	**CIR Filing**	**Actual**	**Var.**	**CIR Filing**	**Actual**	**Var.**	**CIR Filing**	**Fcst**	**Var.**	**CIR Filing**	**Actual/Fcst**	**Var.**
Gross	555.0	465.4	-16%	687.3	617.1	-10%	522.0	549.0	5%	458.2	563.6	23%	547.7	519.7	-5%	2,770.3	2,714.8	-2%
Customer Contributions	(15.3)	(30.1)	97%	(15.8)	(32.8)	108%	(16.4)	(28.7)	75%	(17.2)	(39.2)	128%	(17.8)	(79.1)	345%	(82.4)	(209.9)	155%
Net	**539.7**	**435.3**	**-19%**	**671.6**	**584.3**	**-13%**	**505.7**	**520.3**	**3%**	**441.0**	**524.4**	**19%**	**529.9**	**440.6**	**-17%**	**2,687.9**	**2,504.8**	**-7%**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 171:

Reference(s): **Exhibit U, Tab 2, Schedule 2, Appendix C**

a) Please confirm that Appendix C to Exhibit U / Tab 2 / Schedule 2 compares the actual / forecast capital expenditures to the planned amounts that were proposed in the 2015-2019 Custom IR application (as opposed to the OEB-approved amounts).

b) Please explain why Toronto Hydro compares actual ISAs to OEB-approved ISAs but compares actual capital expenditures to the planned capital expenditure amounts from the 2015-2019 Custom IR application.

c) Please provide a revised Exhibit U / Tab 2 / Schedule 2 / Appendix C that compares the actual / forecast capital expenditures to the amounts that were approved in the 2015-2019 Custom IR proceeding (as opposed the planned amounts).

d) Please provide revised tables both in the format of Appendix C (comparing to planned amounts) and as requested in part (c) to this question (comparing to approved amounts) that include columns for total historical variance analysis for the period 2015-2019.

RESPONSE:

a) Confirmed.

The difference in presentation is the result of practical limitations Toronto Hydro faced in responding to certain filing requirements and interrogatories. These limitations are described in the evidence. Please refer to Exhibit 2B, Section E4.1; 2B-Staff-75, part (a); and 2B-Staff-75, part (b)(ii) for details.

b) Please see Appendix A.

c) Please see Appendix B and Appendix C.

U-Staff-171 Appendix A

OEB Appendix 2-AB
Capital Expenditure Summary

CATEGORY	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			*$ M*			*$ M*			*$ M*			*$ M*			*$ M*	*$ M*	*$ M*	*$ M*	*$ M*
System Access		97.4			113.0			113.0			153.0			236.0		160.4	189.6	181.3	193.8	207.2
System Renewal		304.1			266.1			250.3			245.5			244.2		306.6	325.7	323.1	339.0	325.5
System Service		37.9			53.3			72.4			31.0			41.5		58.5	72.2	77.1	33.6	38.5
General Plant		79.4			109.5			98.9			58.4			46.4		78.8	93.7	89.0	77.7	85.2
Other		13.5			3.7			10.7			13.0			(1.3)		7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE		532.3			545.6			545.3			500.9			566.9		611.3	690.2	680.4	653.6	665.2
Capital Contributions Received		(40.9)			(34.0)			(47.5)			(65.3)			(123.9)		(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	478.0	491.4	2.8%	466.9	511.6	9.6%	420.6	497.8	18.4%	423.0	435.6	3.0%	451.9	443.0	-2.0%	518.4	581.8	587.1	565.7	574.4
System O&M		116.1			126.5			126.3			139.6			131.0		130.4				

Note: Variances due to rounding may exist

U-Staff-171 Appendix B

OEB Appendix 2-AB
Capital Expenditure Summary

CATEGORY	2015			2016			2017			2018			2019			2015-2019			2020	2021	2022	2023	2024
	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Actual	Var	CIR Filing Plan	Bridge	Var	CIR Filing Plan	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access	103.3	97.4	-5.8%	112.8	113.0	0.2%	122.0	113.0	-7.4%	113.8	153.0	34.4%	111.9	236.0	110.9%	563.8	712.3	26.3%	160.4	189.6	181.3	193.8	207.2
System Renewal	251.7	304.1	20.8%	239.6	266.1	11.0%	256.2	250.3	-2.3%	275.9	245.5	-11.0%	287.3	244.2	-15.0%	1,310.8	1,310.2	0.0%	306.6	325.7	323.1	339.0	325.5
System Service	76.5	37.9	-50.4%	70.7	53.3	-24.6%	65.1	72.4	11.3%	52.6	31.0	-41.0%	80.2	41.5	-48.2%	345.0	236.2	-31.5%	58.5	72.2	77.1	33.6	38.5
General Plant	104.6	79.4	-24.1%	101.5	109.5	7.9%	30.3	98.9	226.4%	34.2	58.4	70.6%	30.3	46.4	53.2%	300.9	392.7	30.5%	78.8	93.7	89.0	77.7	85.2
Other	12.2	13.5	10.9%	11.6	3.7	-67.9%	10.8	10.7	-1.4%	11.5	13.0	13.2%	12.1	(1.3)	-111.1%	58.2	39.6	-31.9%	7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE	548.3	532.3	-2.9%	536.2	545.6	1.8%	484.5	545.3	12.5%	488.0	500.9	2.6%	521.7	566.9	8.7%	2,578.8	2,691.0	4.4%	611.3	690.2	680.4	653.6	665.2
Capital Contributions Received	(17.2)	(40.9)	138.1%	(17.4)	(34.0)	95.3%	(17.1)	(47.5)	177.1%	(18.0)	(65.3)	262.7%	(19.6)	(123.9)	533.0%	(89.3)	(311.6)	248.9%	(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	531.1	491.4	-7.5%	518.8	511.6	-1.4%	467.4	497.8	6.5%	470.0	435.6	-7.3%	502.2	443.0	-11.8%	2,489.5	2,379.4	-4.4%	518.4	581.8	587.1	565.7	574.4
System O&M	128.8	116.1	-9.9%		126.5			126.3			139.6			131.0			639.5		130.4				

Note: Variances due to rounding may exist

U-Staff-171 Appendix C

OEB Appendix 2-AB
Capital Expenditure Summary

CATEGORY	2015			2016			2017			2018			2019			2015-2019 Total			2020	2021	2022	2023	2024
	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Actual	Var	CIR Filing (-10%)	Bridge	Var	CIR Filing (-10%)	Bridge	Var	Forecast	Forecast	Forecast	Forecast	Forecast
	$ M			$ M			$ M			$ M			$ M			$ M			$ M	$ M	$ M	$ M	$ M
System Access		97.4			113.0			113.0			153.0			236.0			712.3		160.4	189.6	181.3	193.8	207.2
System Renewal		304.1			266.1			250.3			245.5			244.2			1,310.2		306.6	325.7	323.1	339.0	325.5
System Service		37.9			53.3			72.4			31.0			41.5			236.2		58.5	72.2	77.1	33.6	38.5
General Plant		79.4			109.5			98.9			58.4			46.4			392.7		78.8	93.7	89.0	77.7	85.2
Other		13.5			3.7			10.7			13.0			(1.3)			39.6		7.0	9.0	9.8	9.5	8.7
GROSS TOTAL EXPENDITURE		532.3			545.6			545.3			500.9			566.9			2,691.0		611.3	690.2	680.4	653.6	665.2
Capital Contributions Received		(40.9)			(34.0)			(47.5)			(65.3)			(123.9)			(311.6)		(92.9)	(108.4)	(93.2)	(87.8)	(90.9)
NET TOTAL EXPENDITURE	478.0	491.4	2.8%	466.9	511.6	9.6%	420.6	497.8	18.4%	423.0	435.6	3.0%	451.9	443.0	-2.0%	2,240.4	2,379.4	6.2%	518.4	581.8	587.1	565.7	574.4
System O&M		116.1			126.5			126.3			139.6			131.0			639.5		130.4				

Note: Variances due to rounding may exist

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 172:

Reference(s): **Exhibit U, Tab 2, Schedule 2, Appendix A**
Chapter 2 Appendices, Tab 2-AA

Preamble:

The total capital expenditure amounts are relatively unchanged in each of 2018 and 2019 as between originally filed and updated amounts. For 2018, the total capital expenditures (less non rate-regulated) were originally forecast to be $434.7 million and have been updated to $434.9 million. For 2019, the total capital expenditures (less non rate-regulated) were originally forecast to be $425.7 million and have been updated to $425.3 million. However, at the program level, the changes in capital expenditures as between originally filed and updated amounts are material for some programs.

a) Please provide a revised Appendix A that includes, for 2018 and 2019, additional columns showing the originally filed capital expenditure amounts.

b) Please explain why, in the context that there have been some material changes to the capital expenditures at the program level in 2018 and 2019, Toronto Hydro is not proposing any changes to the 2020-2024 capital expenditures.

RESPONSE:

a) Please refer to Toronto Hydro's response to U-VECC-71, part (a).

b) Toronto Hydro has updated its 2020 capital expenditures to address carry-over work from 2018-2019. Please see the response to U-Staff-168 for details.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 173:

Reference(s): **2B-Staff-80, Part (b)**
JTC1.8
Exhibit U, Tab 2, Schedule 2, p. 10

Preamble:

Toronto Hydro stated that the $36,000 cost per customer for rear-lot conversion projects is based on an average for three projects (Markland Woods, Thorncrest, and Forest Hill) that were completed during the 2013-2017 period.

Toronto Hydro stated that it selected the noted projects to determine the average cost per customer for the 2020-2024 rear-lot conversion program as they were the most recently completed projects at the time that the application was filed.

Toronto Hydro provided updated 2018 actual costs for rear-lot conversion projects as part of the application update.

a) Please recalculate the average cost per customer based on all rear-lot conversion projects completed (both civil and electrical work) during the 2013-2018 period. As part of the response, please provide a table that lists each project including: (i) the name of the project; (ii) the number of customers converted; (iii) the total civil costs; (iv) the total electrical costs; (v) the average cost per customer; (vi) the year the project was started; and (vii) the year the project was completed.

RESPONSE:

The tables below provide the information requested (i) through (vii). Table 1 has been reproduced and expanded from JTC1.8 and Table 2 represents the additional project area completed in 2018.

Table 1: Projects used to Determine the Cost per Customer for Rear-Lot Conversion

Project Area	Number of Customers	Year	Phase	Total Cost	Cost per Customer
Markland Woods	806	2014-2017	Civil	$17,952,579	$22,274
			Electrical	$9,054,905	$11,234
			Total	**$27,007,484**	**$33,508**
Thorncrest	297	2015-2016	Civil	$7,435,695	$25,036
			Electrical	$3,051,972	$10,276
			Total	**$10,487,667**	**$35,312**
Forest Hill	135	2013	Civil	$3,197,449	$23,685
			Electrical	$2,128,706	$15,768
			Total	**$5,326,155**	**$39,453**

The table below provides details on 2018 work in the Rear-Lot Conversion Program.

Table 2: Cost per Customer for 2018 Rear-Lot Conversion Work

Project	Number of Customers	Year	Phase	Total Cost	Cost per Customer
Thorncrest	158	2017-2018	Civil	$4,971,023	$31,462
			Electrical	$1,313,671	$8,314
			Total	**$6,284,694**	**$39,777**

The average cost per customer for the project areas, including the 2018 project, is $37,012.

Please note that as noted in JTC1.8, rear lot areas are converted using a phased approach and are undertaken through discrete sub-projects. The project areas listed in the tables above are those that were started in 2013, completed by 2018, and have expenditures grouped in a manner that may be appropriately used to calculate unit costs on a per customer basis.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 174:

Reference(s): **2B-Staff-80, Part (c)**
JTC1.9
Exhibit U, Tab 2, Schedule 2, p. 10

Preamble:

Toronto Hydro stated that the $29,000 cost per pole for box construction projects is based on an average for four projects that were completed during the 2015-2017 period.

Toronto Hydro stated that it selected the noted projects to determine the average cost per pole for the 2020-2024 box construction program as they were the most recently completed projects at the time that the application was filed.

Toronto Hydro provided updated 2018 actual costs for box construction projects as part of the application update.

a) Please recalculate the average cost per pole based on all box construction projects completed during the 2013-2018 period. As part of the response, please provide a table that lists each project including: (i) the name of the project; (ii) the number of poles; (iii) the average cost per pole; (iv) the year the project was started; and (v) the year the project was completed.

RESPONSE:

The table below lists projects that were fully completed during the 2013-2018 period. The average cost per pole of all projects is $29,579.

Table 1: Box Construction Projects Completed between 2013-2018

Project Name	Number of Poles	Average Cost Per Pole	Project Start Year	Project End Year
Carlaw B1E B13E B5E Conversion	336	$10,180	2016	2018
College B4CD Conversion	36	$44,475	2013	2014
College B7CD Conversion	81	$13,142	2013	2014
Dufferin B2DN Conversion	205	$21,567	2013	2015
Dufferin B5DN Conversion	102	$27,768	2013	2013
Hammersmith B2HS Conversion (P06 Convert 4kV B2HS to 13.8kV)	162	$18,754	2015	2017
Hazelwood B7HW Conversion	104	$38,150	2013	2015
Junction B15J Conversion (High Park Area Conversion)	241	$23,100	2015	2015
Junction B3J Conversion	170	$17,574	2017	2018
Junction B5J Conversion	33	$69,175	2013	2014
Junction B9J Conversion	14	$67,067	2013	2013
Keele Conversion South of St Clair	50	$43,400	2015	2015
Keele Conversion North of St Clair	102	$36,317	2013	2014
Millwood/Merton B1MR B2MR B2MD B3MD Conversion[1]	1035	$15,651	2013	2015
Millwood/Merton B5MR Conversion	138	$35,695	2016	2016
Wiltshire B1W Conversion	60	$19,316	2017	2018
Wiltshire B3W Conversion	75	$12,033	2017	2018
Wiltshire B6W Conversion	89	$19,933	2013	2013
Wiltshire/Junction B2W B1W B11J Conversion (Wiltshire MS Voltage Conversion)	109	$28,700	2015	2016

Note 1: The Millwood/Merton B1MR B2MR B2MD B3MD Conversion project was comprised of a number of sub-projects that have been combined here due to the overlapping nature of the work executed within these projects.

The significant variations observed in average cost per pole between the projects is due to complexities attributed to specific project area characteristics, discussed in Exhibit 2B, Section E6.1, Page 25, Lines 6-16.

As also stated in the response to JTC1.9, the projects used to determine the average cost per pole for the Box Conversion segment were selected because they were the most recently completed ones at the time of filing. Toronto Hydro also used data analysis, project assessment, and engineering judgement to confirm that these projects were the most representative projects of the work to be executed over the 2020-2024 period under the Box Conversion segment.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 175:

Reference(s): 2B-AMPCO-21
Exhibit 2B, Section A4, p. 10, Figure 3

<u>Preamble:</u>

Toronto Hydro provided the proportion of assets that would be in service past useful life at the end of 2017. As part of interrogatory 2B-AMPCO-21, Toronto Hydro also indicated what percentage of assets were in HI4 or HI5 condition at the end of 2017.

a) Please update the pie chart in Exhibit 2B / Section A4 / p.10 / Figure 3 based on the 2018 year end (as opposed to 2017 year end as originally filed).

b) Please update the pie chart in 2B-AMPCO-21 / part (b) based on the 2018 year end (as opposed to the 2017 year end as originally filed).

c) Please update the pie chart in Exhibit 2B / Section A4 / p.10 / Figure 3 based on the 2018 year end, showing only those same assets found in the pie chart in 2B-AMPCO-21 / part (b).

RESPONSE:

a) Please see Figure 1 below, in which the original “Assets at End of Useful Life by 2018” pie chart segment has been updated to represent “Assets at End of Useful Life by 2019.”

To ensure consistency in the length of the time horizon covered by the chart, Toronto Hydro has also shifted the "Assets to Reach Useful Life by End of Forecast Period (2025)" segment of the pie chart so that it now represents "Assets to Reach Useful Life by 2026."

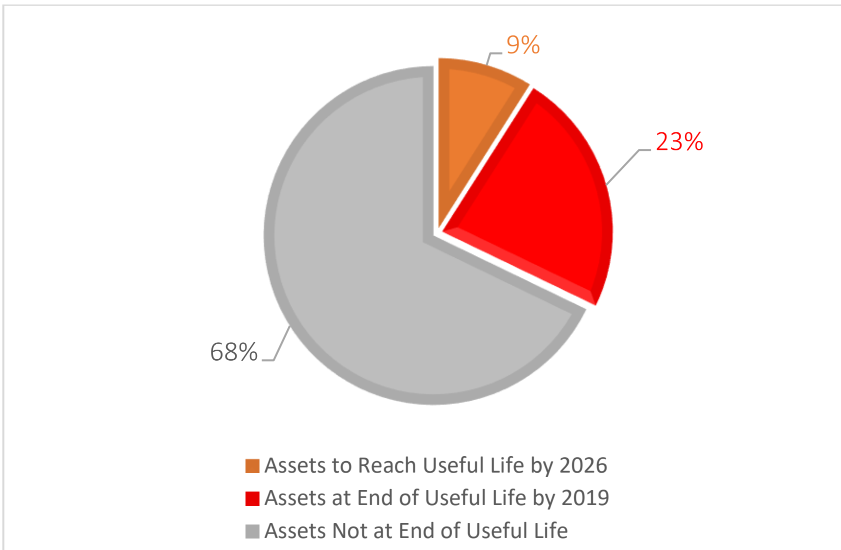

Figure 1: Percentage of Assets Past Useful Life (Updated)

b) Please see Figure 2 below, in which the original "Percentage of Assets with Health Index Scores of HI4 or HI5" pie chart in 2B-AMPCO-21 has been updated to represent "Assets with Health Index Scores of HI4 and HI5 by 2019". To ensure consistency in the length of the time horizon covered by the chart, Toronto Hydro has also shifted the "Assets with Health Index Scores of HI4 and HI5 by end of Forecast Period (2025)" segment of the pie chart so that it now represents "Assets with Health Index Scores of HI4 and HI5 by 2026". The sum of these two pie chart segments is approximately 25 percent, which is unchanged from the original graph in 2B-AMPCO-21, part (b).

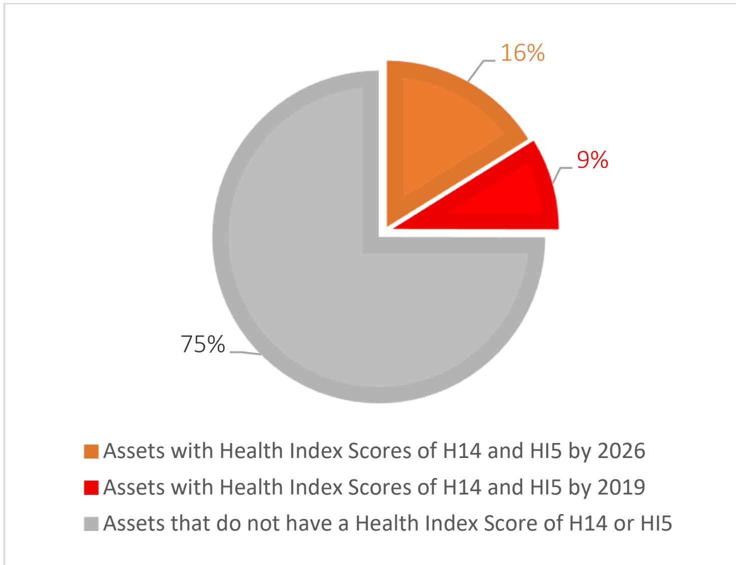

Figure 2: Percentage of Assets with Health Index Scores of HI4 and HI5 (Updated)

c) Please see the updated chart below, which is the same as the chart provided in response to part (a), but excludes assets for which Toronto Hydro does not have an Asset Condition Assessment ("ACA") algorithm.

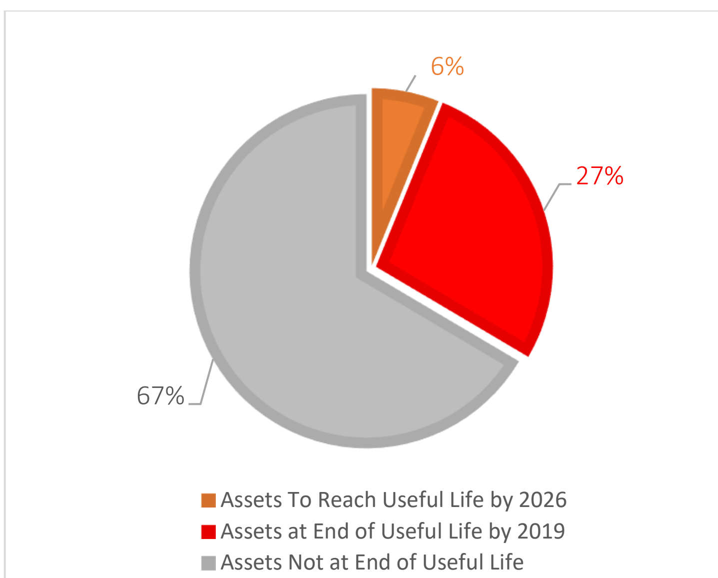

Figure 3: Percentage of Assets Past Useful Life (Excluding Asset with No ACA)

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 176:

Reference(s): **Exhibit U, Tab 3, Schedule 1, p. 3**
3-Staff-106

Preamble:

In 3-Staff-106, OEB staff inquired about the impacts on the load forecast due to the TTC Spadina extension and the proposed Eglinton Crosstown project. Toronto Hydro stated that the updated historical loads now contain the full impact of the Spadina extension and therefore are reflected in the load forecast.

Toronto Hydro noted that the load impacts of the Eglinton Crosstown project are uncertain in both level and timing, and would not have a material impact on rate setting for the IR period. They have not been reflected in the updated load forecast.

a) In stating that "[t]he updated historical loads now contain the full impact of the Spadina extension and therefore are reflected in the load forecast", is Toronto Hydro explaining that the added year of 2018 actuals now includes the incremental load of the operation of the Spadina line extension on Toronto Hydro's system? If possible, please provide the direct impact of this change on Toronto Hydro's load forecast.

b) In stating that "[a]s noted in Toronto Hydro's interrogatory response [3-Staff-106], the load impacts of the Eglinton Crosstown project are uncertain in both level and timing, and would not have a material impact on rate setting for the CIR period", what is the analysis that Toronto Hydro has done in order to reach its conclusion that "… the load impacts of the Eglinton Crosstown project … would not have a material impact on rate setting for the CIR period"?

c) Are all capital costs to connect the Eglinton Crosstown project, including reinforcement of Toronto Hydro's upstream assets (e.g., feeders and transformer station equipment) funded through capital contributions from Metrolinx? Please explain your response.

RESPONSE:

a) Toronto Hydro's load forecast regression models have been estimated based on historical data that now includes the full load of the Spadina Line Extension; as such, there was no basis to make a direct change to the forecast to account for it.

b) As described in the referenced interrogatory response, the Eglinton Crosstown project is estimated to come online after 2020; as such, it would not impact proposed 2020 rates. 2021-2024 proposed rates are based on Toronto Hydro's CPCI formula, which includes a growth factor component "g" that accounts for change in revenue due to load and customer growth. Toronto Hydro determined that the calculation of the growth factor value remains unaffected by the inclusion of the preliminary forecast loads for the Eglinton Crosstown project.

c) No, not all capital costs to connect the Eglinton Crosstown project are funded through contributions from Metrolinx. The costs, including expansions, are funded in accordance with the Capital Contribution Policy as per Toronto Hydro's Conditions of Service. This is equivalent to any other customer connection, which involves an economic evaluation to determine the contribution amounts.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 177:

Reference(s): **Exhibit U, Tab 3, Schedule 1, p. 5**
Exhibit U, Tab 7, Schedule 1, p. 1

Please advise whether the reduction in the 2019-2024 customer forecast for the large use class is related to the reclassification of certain large use customers as GS 1000-4999 kW customers. If so, please explain why there is also a reduction to the 2019-2024 customer forecast for the GS 1000-4999 kW rate class.

RESPONSE:

As noted in Exhibit U, Tab 3, Schedule 1, Table 3, the forecast for both the Large User and the GS 1000-4999 kW rate classes is based on the last actual value.

The reclassification of Large Use customers into the GS 1000-4999 kW rate class during 2018 is the driver of the reduction in the Large User rate class. For the GS 1000-4999 kW class, the addition of the customers re-classed down from the Large User class was exactly offset by a reduction in the number of customers previously in this rate class, resulting in an unchanged forecast of number of customers in this class.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 178:

Reference(s): Exhibit U, Tab 3, Schedule 2, p. 2

<u>Preamble:</u>

Toronto Hydro proposed a $3.0 million reduction to specific service charge revenue in 2020 due to the removal of the Collection of Account and Install / Remove Load Control Devices charges in accordance with the Customer Service Rules review.

Toronto Hydro also proposed increased other income of $2.0 million in 2020 due to reduced merchandising and jobbing costs as a result of capitalization of major assets related to accident claims.

a) Please explain how the $3.0 million reduction to the specific service charge revenue was estimated. Please provide 2015-2018 historic revenues associated with the Collection of Account and Install / Remove Load Control Devices specific service charges.

b) Please further explain the capitalization change for major assets related to accident claims.

RESPONSE:

a) Toronto Hydro estimated the decrease in revenues associated with the Collection of Account and Install/Remove Load Control Device charges by applying the OEB-approved specific service charges to historical annual volumes. Tables 1 and 2 below show the calculations.

Table 1: Collection of Account Charge Calculation

Collection of Account Charge		2020 Test
A	Rate	$55.00
B	Volume (units)	52,570
C = A*B	Revenue	$2,891,350

Note 1: Variances might exist due to rounding

Table 2: Install/Remove Load Control Device Charge Calculation

Install/Remove Load Control Device – during regular hours charge		2020 Test
D	Rate	$120.00
E	Volume (units)	307
F = D*E	Revenue	$36,840
Install/Remove Load Control Device – after regular hours charge		**2020 Test**
G	Rate	$400.00
H	Volume (units)	15
I = G*H	Revenue	$6,000
F+I	Total Revenues	$42,840

Note 1: Variances might exist due to rounding

The historical revenues from these charges are noted in Table 3 below.

Table 3: Historical revenues for Collection Service Charges and Install/Remove Load Control Device Charge

	Actual			
	2015	**2016**	**2017**	**2018**
Collection Service Charge	$2,986,342	$5,165,058	$3,130,010	$2,495,315
Install/Remove Load Control Device Charge	$45,130	$75,880	$51,760	$12,600
Total	**$3,031,472**	**$5,420,938**	**$3,181,770**	**$2,507,915**

b) As part of its periodic review of accounting policies, Toronto Hydro reassessed the accounting treatment of claim costs, and determined that the costs associated with the remediation of accident claims are capital in nature and therefore should be reclassified from revenue offsets to capital assets. This approach is aligned with Toronto Hydro's Capitalization Policy for the initial recognition of capital assets, which is provided in Exhibit 2A, Tab 5, Schedule 1, Appendix A.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 179:

Reference(s): Exhibit U, Tab 3, Schedule 2, Appendix A
Technical Conference Transcripts, Vol. 3, pp. 25-26

Preamble:

Toronto Hydro has had (or forecasts) gains on the disposition of utility and other property in every year 2015-2019. However, Toronto Hydro forecasts zero revenue from gains on the disposition of utility property in 2020.

At the technical conference, Toronto Hydro stated that at the time of the development of its application it did not have a plan for further disposition of assets.

a) Please confirm that it continues to be Toronto Hydro's position that there is no 2020 revenue related to the gain on disposition of utility and other property as no assets have been planned for sale in 2020.

RESPONSE:

Confirmed.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 180:

Reference(s): Exhibit U, Tab 4A, Schedule 1, pp. 2, 5

Preamble:

Toronto Hydro stated that its customer-owned equipment services costs in 2018 were in line with 2017 but $1.6 million higher than originally forecast due to the increase in volume of customer requests for Toronto Hydro to facilitate safe entry into customer-owned vaults.

Toronto Hydro has increased its 2020 forecast of customer-owned equipment service costs by $1.0 million relative to the original filing due to this higher demand.

a) Please further explain the reason for this increase in customer-owned equipment service costs relative to the original 2018 forecast. Please also explain why these increased costs are expected to continue into 2020.

RESPONSE:

The increase in costs in the Customer-Owned Equipment Services segment of $1.6 million over the original 2018 forecast is due to the increase in volume of customer requests for vault access. These costs are expected to continue as there has been no indication of the volume of requests decreasing.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 181:

Reference(s): **Exhibit U, Tab 4A, Schedule 1, p. 6**
4A-Staff-115, part (b)

Please explain why the 2020 local demand response budget was increased by $0.8 million (from zero) as part of the application update. Please provide the response in the context of the information provided by Toronto Hydro in 4A-Staff-115 / part (b).

RESPONSE:

As noted in Exhibit U, Tab 4A, Schedule 1, page 2, at lines 6 to 8, the $0.8 million change in the 2020 test year relates to Local Demand Response costs that were inadvertently omitted from the original OM&A budget. For greater clarity, Exhibit 4A, Tab 2, Schedule 9, page 7, Table 3 inadvertently omitted 2020 Test year forecasted expenditure for Local Demand Response (i.e. “-“), whereas page 27, Table 6 (of the same schedule) correctly included $0.8 million for the 2020 Test year.

As noted in Exhibit 4A, Tab 2, Schedule 9, page 26, lines 16 to 18, and in 4A-Staff-115 (part b), Toronto Hydro plans to continue demand response activities at Cecil TS. The $0.8 million is the estimated cost associated with carrying over the contractual DR capacity that was procured at Cecil TS under the 2015-2019 Local DR program, or procure new contracts if necessary, ensuring a smooth transition between the 2015-2019 and the 2020-2024 phases of the program.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 182:

Reference(s): Exhibit U, Tab 4A, Schedule 1, p. 7

Please explain why the reduced property tax and utilities expenses experienced in 2018, which were $1.2 million lower than originally forecast, are not expected to continue in 2019 and 2020.

RESPONSE:

Utilities expenses under the Utilities and Communications segment of the Facilities Management Program are dependent upon seasonal temperatures. Toronto Hydro's overall energy usage across its facilities was higher in Q1 2019 compared to Q1 2018. In addition, the utility experienced various technical issues with its HVAC systems during the winter of 2017-2018 and spring 2018, which reduced energy usage and contributed to the lower than forecasted expenses in this segment. Based on the higher energy usage observed so far in 2019 and the exceptional technical circumstances that reduced usage in 2018, Toronto Hydro expects utilities costs to trend in 2019 and 2020 as forecasted.

Lower expenditures in the Property Taxes segment were attributable to the City of Toronto's Vacant Commercial & Industrial Unit Tax Rebate Program. The City of Toronto ended this program on July 1, 2018. As a result, tax rebates will not be available in 2019 and 2020.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 183:

Reference(s): Exhibit U, Tab 4A, Schedule 1, p. 8

Preamble:

Toronto Hydro stated that the costs of the supply chain program were approximately $1.3 million lower than originally forecast. The difference is due to changes in the accounting treatment for open bin equipment. Toronto Hydro stated that these changes are not expected to carry forward into the 2019 budget.

a) Please further explain the accounting change that occurred in 2018 and explain why the change would not continue in 2019 and 2020.

RESPONSE:

As mentioned in Exhibit U, Tab 4A, Schedule 1, section 2.13, the variance in the Supply Chain Services program is due to a change in the accounting treatment for open bin equipment costs as well as various credits from inventory rebates. Toronto Hydro's standard approach is to allocate these costs and credits directly to the applicable OM&A and capital programs. However, in 2018, these items were inadvertently mapped to the Supply Chain Services program with a corresponding offset in the On-cost Recovery segment, which is presented in the Allocations and Recoveries program in Exhibit U, Tab 4A, Schedule 1, Appendix C, OEB Appendix 2-JC. This one-time change in the allocation methodology did not impact the overall 2018 OM&A, and is not expected to continue in 2019 and 2020 as Toronto Hydro expects to revert to its standard allocation methodology.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 184:

Reference(s): **Exhibit U, Tab 4A, Schedule 1, p. 9**
JTC3.10

Preamble:

Toronto Hydro stated that the 2018 customer care costs were $5.3 million lower than the forecast provided originally. However, no changes were made to the 2019 and 2020 forecast for the customer care budget.

Toronto Hydro originally anticipated bad debt expense to increase in 2018. Although this expectation did not materialize in 2018, Toronto Hydro continues to believe that it is reasonable, based on the trends and indicators discussed in JTC3.10, to expect an increase in bad debt over the forecast period.

a) Please provide a detailed breakdown of the $5.3 million reduction to customer care costs between the original evidence and the updated evidence. For each sub-category, please explain why the savings are not expected to continue in 2018 and 2019.

b) Please provide a table showing the updated bad debt expense for 2015-2020.

c) Please explain why the trends and indicators discussed in JTC3.10 should be considered valid when the historical actuals do not reflect an increase in bad debt expense.

RESPONSE:

a) Table 1 below shows the detailed breakdown of the $5.3 million variance between the Customer Care Program costs for 2018 between Exhibit 4A, Tab 2, Schedule 14 and Exhibit U, Tab 4A, Schedule 1, section 2.14:

Table 1: Detailed breakdown of Customer Care Program costs ($ Millions)

	2018 Bridge	2018 Actual	Variance
Internal Labour	16.0	15.5	**(0.5)**
External Services	15.2	13.1	**(2.1)**
Materials	0.2	0.1	**(0.1)**
Other	11.6	9.0	**(2.7)**
Total	**43.0**	**37.7**	**(5.3)**

Note 1: Differences may exist due to rounding.

The variance in 2018 is primarily attributable to the following factors:

- Internal labour costs were lower due to the timing of filling vacant positions. A number of vacancies were filled in the latter part of 2018 and additional hiring is planned for 2019, which will return the labour costs back to forecasted levels. Toronto Hydro was able to temporarily mitigate the resource shortage by hiring short term contractors, reprioritizing project work, and adjusting project scopes.
- External Services were lower than forecasted because of temporary underspend in services needed to support the management of bad debt. Toronto Hydro is currently putting into action an alternative arrears management strategy to better align its operations with the seasonality of the new disconnections policy. This strategy, which began to take effect in 2019, is needed to ensure that residential bad debt costs continue to be managed in an effective way under the winter disconnections moratorium framework.

- In the Other category, Toronto Hydro experienced a downward adjustment in the accounting provision for bad debt for both electricity accounts and non-electricity accounts. Please refer to part (c) of this response for more information.

b) Please see Table 2 below:

Table 2: Bad Debt Expense 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Non-Electricity Accounts	0.5	(1.7)	0.6	(0.0)	0.3	0.3
Electricity Accounts	6.6	5.2	4.7	4.4	6.7	6.8
Total Bad Debt Expense	**7.1**	**3.5**	**5.3**	**4.3**	**6.9**	**7.1**

Note 1: Differences may exist due to rounding.

c) The trends and observations outlined in Toronto Hydro's response to undertaking JTC3.10 are valid because they reflect management's experienced assessment of the key factors and indictors that affect bad debt levels. Historical experience is one of the indicators that Toronto Hydro uses to forecast bad debt. However, historical results in any one year are not a reliable indicator of future results because bad debt write-offs are a lagging measure, can vary significantly year over year, and are influenced by a variety of factors. For these reasons, Toronto Hydro's experience is that when forecasting bad debt, a longer-term historical view is more appropriate and useful. When this view is applied in the context of the 2020 test year, the forecasted amounts are aligned with the utility's historical experience dating back to 2015.

As noted above, in forecasting bad debt Toronto Hydro considers a number of other factors in addition to historical performance. This includes macroeconomic indicators, interest rate trends, bankruptcy trends, customer growth, and public policy changes such as the reduction in security deposit holding periods for small business customers pursuant to the upcoming Customer Service Rules changes.

Furthermore, as outlined in JTC3.10, the bad debt risk is expected to increase in 2020 because of the longer periods of time for which residential customer debt remains outstanding over the winter disconnection moratorium. The relatively lower bad debt write-offs experienced in 2017 and 2018 years are likely attributable to lower average billed amounts as a result of recent public policy initiatives such as the Fair Hydro Plan, and the longer timespan over which receivables remain outstanding (the duration from initial billing to write-off) due to the winter disconnection moratorium. In the 2020 test year, as the growing body of debt moves through to the end of the collection process, Toronto Hydro expects to see higher write-offs than in recent years, similar to pre-2017 levels.

Toronto Hydro also notes that up to 50 percent of bad debt in any given year relates to commercial accounts, and is subject to different influences. As can be seen in Figure 3 and Figure 4 of the response to JTC3.10, both the overall commercial accounts receivable balances and the commercial average balance per customer are somewhat higher in 2018 versus 2015 levels, after peaking in 2016.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 185:

Reference(s): **Exhibit U, Tab 4A, Schedule 3, p. 2**
Exhibit U, Tab 4A, Schedule 3, Appendix A

Preamble:

Toronto Hydro noted that it hired a lower number of FTEs in 2018 than it had originally forecast. Toronto Hydro stated that this was in large part due to the delay in hiring Power Line Technicians (PLTs) as Toronto Hydro was unable to come to an agreement with respect to this role with the Power Workers Union (PWU).

a) Please discuss whether the negotiation issue with respect to the PLT position is expected to have an impact on 2019 and 2020 FTEs.

b) Please advise whether Toronto Hydro is currently on track to hire approximately 100 FTEs between 2018 and 2019 (1,425 in 2018 to 1,523 in 2019). If not, please explain what impact this will have on the 2020 test year FTE count (and associated compensation).

RESPONSE:

a) The unsuccessful negotiation with the Power Workers' Union (PWU) to hire into the Power Line Technician (PLT) position has resulted in a hiring delay of approximately 50 FTEs for 2019. In April 2019, the utility initiated hiring into the PLT role without the union's support. This role, which is a standard in the industry and a recognized red seal trade, provides Toronto Hydro enhanced flexibility to deploy internal resources to work on both underground and overhead assets. Toronto Hydro is pursuing the PLT position because it believes that it is in the best interests of customers as it enables more efficient execution of work and increases the utility's ability to respond to customers.

Between January and May 2019, 59 new external employees were hired. The delay in hiring PLTs is expected to some impact on 2019 and 2020 FTEs. However, in accordance with the utility's multi-faceted staffing strategy, Toronto Hydro continues to rely on both internal and external resources to deliver its work plans and provide safe and reliable service to customers. Over the 2020-2024 period, the utility intends to continue to replenish its certified and skilled trade positions, including the new PLT role. This effort must be paced to ensure the safe absorption of new resources and proper knowledge transfer from retiring employees.

b) Please refer to Toronto Hydro's response to interrogatory U-VECC-87 part (b).

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 186:

Reference(s): **Exhibit U, Tab 4A, Schedule 3, p. 5**
Exhibit U, Tab 4A, Schedule 3, Appendix C

<u>Preamble:</u>

Table 5 presents the actual and forecast OPEB costs for the period 2015 to 2020. The amount presented for 2020 underpins what is included in the test period revenue requirement related to OPEBs.

a) Please explain why the years 2019 and 2020 do not agree to the updated actuarial valuation.

b) Please update Table 5 so that it reflects the OPEB expense as calculated in the updated actuarial valuation. Please advise whether Toronto Hydro agrees that OPEB expense calculated based on the updated actuarial valuation should be the amount reflected in the proposed revenue requirement.

RESPONSE:

a) Toronto Hydro assumes the correct reference for this IR is Exhibit U, Tab 4A, Schedule 3, page 4. The reduction in OM&A resulting from the updated actuarial valuation was reflected in Exhibit U, Tab 4A, Schedule 1, page 1, Table 1, under "Common Costs and Adjustments". Toronto Hydro proposes to flow this change through the applicable appendices, revenue requirement work form, and cost allocation models as part of the Draft Rate Order process.

b) See below for updated Table 5, including Toronto Hydro's revised proposal for the 2020 test year.

Table 5: Post-employment Benefit Costs (2015-2020) ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Benefit Costs	17.7	15.3	18.0	10.6	13.1	13.4
Capitalized Amounts	7.7	6.4	8.1	4.8	5.8	6.0
Expensed Amounts	10.0	8.9	9.9	5.8	7.3	7.4

Please refer to part (a) of this response with respect to Toronto Hydro's proposal for updating the revenue requirement work form.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 187:

Reference(s): Exhibit U, Tab 4B, Schedule 1, p. 3

Preamble:

Toronto Hydro stated that it updated its 2019 derecognition forecast based on a four-year average as opposed to a three-year average, which was used in the original filing.

a) Please provide the calculations supporting both the 2019 and 2020 derecognition expense forecasts. Please advise whether the derecognition expense in 2019 and 2020 have been forecast on the same basis. If they have not been forecast on the same basis, please provide rationale and recalculate the 2020 derecognition expense on the same basis as 2019.

RESPONSE:

Toronto Hydro described its approach to forecast derecognition expense in 9-Staff-156 (d). The calculation of the 2019 and 2020 derecognition expense forecasts included in the application update is consistent with that, with the following exceptions:

- In the pre-filed evidence, derecognition related to meter assets was calculated based on forecasted asset units; whereas in the application update, the four-year historical average was applied; and

- In the pre-filed evidence, derecognition for the remaining capital projects was calculated based on a three-year historical average; whereas in the application update, four-year historical averages were applied (see Table 1 below).

In both the pre-filed evidence and the application updated forecasts, derecognition expense for large, discreet projects where assets to be removed from service were identifiable, derecognition was specifically forecasted.

2020 derecognition expense calculated on the same basis as the updated 2019 derecognition, is presented in Table 1.

Table 1: 2019-2020 Derecognition Expense – Application Update ($ Millions)

	Four-year Average	2019 Capital Expenditures	2019 Re-forecasted Derecognition	2020 Capital Expenditures	2020 Re-forecasted Derecognition
Planned Capital	7%	222.5	15.6	276.4	19.0
Reactive Capital	6%	44.2	2.9	48.7	3.1
Streetlighting Capital	17%	3.4	0.6	2.4	0.4
Meter Capital	20%	17.1	3.4	18.0	3.5
Total		**287.2**	**22.4**	**345.4**	**26.1**

Derecognition for 2020 as calculated in the application update ($26.1 million) is generally consistent (within $0.3 million) with the 2020 derecognition forecast included in the pre-filed evidence ($25.8 million).

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 188:

Reference(s): Exhibit U, Tab 4B, Schedule 2

Preamble:

The Government of Canada's 2018 Fall Economic Statement was tabled on November 21, 2018.

It proposes the following measures for certain eligible property acquired after November 20, 2018:

- Accelerated Investment Incentive – Providing an enhanced first-year allowance for certain eligible property that is subject to the Capital Cost Allowance (CCA) rules. In general, the incentive will be made up of two elements:
    - applying the prescribed CCA rate for a class to up to one-and-a-half times the net addition to the class for the year
    - suspending the existing CCA half-year rule (and equivalent rules for Canadian vessels and class 13 property).

- Full Expensing for Manufacturers and Processors – Allowing businesses to immediately write off the full cost of machinery and equipment used for the manufacturing or processing of goods (class 53).

- Full Expensing for Clean Energy Investments – Allowing businesses to immediately write off the full cost of specified clean energy equipment (classes 43.1 and 43.2).

The Federal Government's 2019 Budget, announced on March 19, 2019, confirmed the Government's intention to proceed with the above proposals.

a) Please confirm whether Toronto Hydro has reflected the impact of the new accelerated CCA rules in its Corporate Tax / PILs calculations for 2020-2024 that are currently on the record of this proceeding.

b) If the accelerated CCA is not reflected within Toronto Hydro's 2020-2024 PILs calculations, please explain why. Please also provide updated detailed PILs calculations and supporting CCA tables for the period 2020-2024 that reflect the new accelerated CCA rules.

c) As the accelerated CCA rules are effective November 20, 2018, please advise whether Toronto Hydro prepared its 2018 corporate tax return using these new CCA rules. If not, please explain why.

d) In the context that the approved 2018 and 2019 rates were underpinned by the old CCA rules, please explain how Toronto Hydro is planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the difference between the PILs amounts included in rates for those years and the PILS amounts that would have been included in rates had they been based on the new accelerated CCA rules.

e) Please provide the calculations for 2018 and 2019 revenue requirement impact had the PILs for those years been calculated using the new accelerated CCA rules.

f) If Toronto Hydro is not planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the change in CCA rules, please explain why such an approach is appropriate.

RESPONSE:

a) Toronto Hydro has not reflected the impact of the new accelerated CCA rules in its 2020-2024 PILs calculations that are currently on the record of this proceeding.

b) Bill C-97, Budget Implementation Act, 2019, No. 1, which proposes to implement the accelerated CCA rules, received first reading in the House of Commons on April 8, 2019. Toronto Hydro had not completed the assessment of the tax consequences of the new rules in time for the submission of the updated application evidence on April 30, 2019.

Please see Appendix A for the estimated updated PILs requirement calculations and supporting CCA tables for the 2019-2024 period that reflect Toronto Hydro's current understanding of the new accelerated CCA rules. These estimates are based on assumptions that may materially change as the legislation is finalized and as new information becomes known and is assessed. The PILs affected by this tax policy change consequently affect the capital-related revenue requirement. As a result, any variance between forecast and actuals in 2018-2019 would flow into the 2015-2019 CRRRVA; any variance between forecast and actuals in 2020-2024 would flow into the 2020-2024 CRRRVA.

Bill C-97 requires the identification of acquisition dates for costs incurred after November 20, 2018 and available for use prior to 2028 in order to qualify for accelerated CCA. This leads to planning complexities in order to estimate the costs that will qualify under the new draft rules.

c) If Bill C-97 is enacted, Toronto Hydro intends to reflect the resulting tax consequences in its corporate tax return for 2018. Toronto Hydro is currently preparing its 2018 corporate tax return which is expected to be filed by June 30, 2019.

d) Toronto Hydro proposes to make ratepayers whole by recording the PILs differences resulting from the new draft tax legislation for 2018 and 2019 in its 2015-2019 CRRRVA. The company has proposed to dispose of its 2019 forecasted CRRRVA account balance in 2020 rates with a true-up in 2021 rates that reflects the variances between the amount disposed in 2020 and 2019 audited financials. Were the CRRRVA not in place, these differences would be credited to customers through Account 1592.

e) Within the time available to produce interrogatory responses, Toronto Hydro could not generate detailed, revised calculations of revenue requirement, cost allocation, rates, and bill impacts that flow through the effects of these changes as they apply to 2018 and 2019.

See Table 1 for the estimated change in PILs resulting from the change in draft tax legislation. These amounts may materially change as the legislation is finalized and as new information become known and is assessed.

The change in tax rules only affects the determination of PILs. Consequently, this does not cause Toronto Hydro to change its operational plans and related costs or values (i.e. OM&A, shared services, capital expenditures, depreciation and fixed assets) provided in evidence.

The estimated change to annual revenue requirement resulting from the new draft tax legislation is expected to be similar to the estimated change in PILs amounts. While Toronto Hydro expects items other than the PILs component of revenue requirement to change (e.g. reduction to PILs used to determine working capital allowance), the resulting annual amounts are not expected to be material.

Table 1: PILs (Grossed-up) ($ Millions)

		2019 Bridge	2020 Test	2021 Test	2022 Test	2023 Test	2024 Test
Current PILs forecast in evidence	(a)	22.1	34.7	36.5	32.7	35.7	42.2
Estimated Updated PILs following existing CCA rule (see Appendix B)	(b)	22.3	29.2	33.5	31.4	35.8	42.0
Estimated decrease in Updated PILs following new accelerated CCA rules	(c)	(10.5)	(16.4)	(11.3)	(17.8)	(7.9)	(1.5)
Estimated Updated PILs following new accelerated CCA rules (See Appendix A)	(d) = (b) + (c)	11.8	12.8	22.2	13.6	27.9	40.5
Estimated change due to new accelerated CCA rules	(d) - (a)	(10.3)	(21.9)	(14.3)	(19.1)	(7.8)	(1.7)

The accelerated investment incentive provides Canadian businesses an opportunity to claim additional CCA for eligible capital investment in the first year of eligibility resulting in reduced tax expense. Eligible property must be acquired after November 20, 2018 and must be available for use before 2028 in order to qualify. A phase-out will begin for property that becomes available for use after 2023, and eliminated completely for assets ready to be put into use after 2027. As a result, not all capital expenditures within this period will be eligible.

The enhanced first-year deduction does not alter the total CCA over the lifetime of the asset; the higher deduction taken in the first year is eventually offset by lower deductions in subsequent years.[1] That is, the incentive results in a tax timing difference – less tax paid (and lesser rates) in the earlier years of the asset lives and more tax paid (and greater rates) in the later years.

f) Not applicable; Toronto Hydro proposes to keep ratepayers whole. Please see Toronto Hydro's response to part (d).

[1] Between 2025 and the end of the depreciable lives of eligible assets, the CCA deduction will be lower (and PILs consequently greater) than it would have been if the draft tax legislation did not exist. As a result, the lower CCA over this period will offset the greater CCA available between 2018 and 2024.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

	T2 S1 line #	2019 Bridge Year Taxable Income	2020 Test Year Taxable Income	2021 Test Year Taxable Income	2022 Test Year Taxable Income	2023 Test Year Taxable Income	2024 Test Year Taxable Income
Net Income Before Taxes		**164,525,122**	**162,460,983**	**170,789,286**	**179,506,254**	**189,690,836**	**199,232,627**
Additions:							
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104	245,421,228	265,539,781	281,534,085	292,284,881	314,013,618	327,126,489
Non-deductible club dues and fees	120	334,453	334,453	334,453	334,453	334,453	334,453
Non-deductible meals and entertainment expense	121	227,915	227,915	227,915	227,915	227,915	227,915
Reserves from financial statements- balance at end of year	126	278,844,000	283,172,000	283,172,000	283,172,000	283,172,000	283,172,000
Financing fees deducted in books	216	1,173,682	1,125,064	1,125,064	1,125,064	1,125,064	1,125,064
Capital Contributions Received (ITA 12(1)(x))		79,065,880	139,706,986	139,706,986	139,706,986	139,706,986	139,706,986
Deferred Revenue (ITA 12(1)(a))		1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Interest expensed on capital leases	290	26,379	20,214	20,214	20,214	20,214	20,214
Prior Year Investment Tax Credits received		2,736,000	2,736,000	2,736,000	2,736,000	2,736,000	2,736,000
Total Additions		**608,929,537**	**693,962,413**	**709,956,717**	**720,707,513**	**742,436,250**	**755,549,121**
Deductions:							
Gain on disposal of assets per financial statements	401	0	0	0	0	0	0
Capital cost allowance from Schedule 8	403	372,707,534	387,885,917	386,301,358	429,658,104	421,851,790	409,407,923
Reserves from financial statements - balance at beginning of year	414	274,566,000	278,844,000	278,844,000	278,844,000	278,844,000	278,844,000
Financing Fees for Tax ITA S.20(1)(e) and (e.1)		1,681,277	1,453,417	1,453,417	1,453,417	1,453,417	1,453,417
ARO Payments - Deductible for Tax when Paid		74,232	75,717	75,717	75,717	75,717	75,717
ITA 13(7.4) Election - Capital Contributions Received		79,065,880	139,706,986	139,706,986	139,706,986	139,706,986	139,706,986
Deferred Revenue - ITA 20(1)(m) reserve		1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Land Lease payment capitalized for accounting		89,423	89,423	89,423	89,423	89,423	89,423
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact		149,000	193,000	193,000	193,000	193,000	193,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact		5,855,808	5,974,528	5,974,528	5,974,528	5,974,528	5,974,528
Lease inducement Book Amortization credit to income		54,792	54,792	54,792	54,792	54,792	54,792
Capital lease payments	391	299,000	310,176	310,176	310,176	310,176	310,176
Total Deductions		**735,642,946**	**815,687,956**	**814,103,397**	**857,460,143**	**849,653,829**	**837,209,962**
NET INCOME FOR TAX PURPOSES		**37,811,714**	**40,735,440**	**66,642,606**	**42,753,624**	**82,473,257**	**117,571,786**
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		**37,811,714**	**40,735,440**	**66,642,606**	**42,753,624**	**82,473,257**	**117,571,786**

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

	T2 S1 line #	2019 Bridge Year Taxable Income	2020 Test Year Taxable Income	2021 Test Year Taxable Income	2022 Test Year Taxable Income	2023 Test Year Taxable Income	2024 Test Year Taxable Income
Total Ontario income taxes before small business deduction	**11.50%**	4,348,347	4,684,576	7,663,900	4,916,667	9,484,425	13,520,755
Ontario Small Business Deduction		0	0	0	0	0	0
Total Ontario income taxes		**4,348,347**	**4,684,576**	**7,663,900**	**4,916,667**	**9,484,425**	**13,520,755**
Effective Ontario tax rate		11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Federal tax rate		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Combined tax rate		**26.50%**	**26.50%**	**26.50%**	**26.50%**	**26.50%**	**26.50%**
Total Income taxes		**10,020,104**	**10,794,892**	**17,660,290**	**11,329,710**	**21,855,413**	**31,156,523**
Investment Tax credits		-1,478,000	-1,478,000	-1,478,000	-1,478,000	-1,478,000	-1,478,000
Miscellaneous Tax credits		-1,258,000	-1,258,000	-1,258,000	-1,258,000	-1,258,000	-1,258,000
Total tax credits		**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**
Corporate PILs/Income Tax Provision for Test Year		**7,284,104**	**8,058,892**	**14,924,290**	**8,593,710**	**19,119,413**	**28,420,523**
Corporate PILs/Income Tax Provision Gross Up [1]	**73.50%**	2,626,242	2,905,587	5,380,867	3,098,413	6,893,394	10,246,855
Income Tax (grossed-up) before tax credits reclass to OM&A		**9,910,346**	**10,964,478**	**20,305,157**	**11,692,123**	**26,012,807**	**38,667,379**
Tax credits reclass to OM&A		**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**
Income Tax (grossed-up) after tax credits reclass to OM&A		**11,785,459**	**12,839,591**	**22,180,270**	**13,567,236**	**27,887,920**	**40,542,492**

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

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2019

Class	Class Description	2019 Opening UCC Balance[2]	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2019 CCA (new accelerated CCA rule applied)	2019 Ending UCC Balance
1	Distribution System - post 1987	$ 1,008,853,279	1,887,242	441,381	2,328,623		$ 1,011,181,902	$ 1,164,312	$ 1,010,017,591	4%	$ 40,418,359	$ 970,763,543
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 227,301,557					$ 227,301,557	$ -	$ 227,301,557	6%	$ 13,638,093	$ 213,663,464
8	General Office/Stores Equip	$ 26,338,689	1,984,010	1,461,339	3,445,349		$ 29,784,038	$ 1,722,675	$ 28,061,364	20%	$ 5,904,541	$ 23,879,498
10	Computer Hardware/ Vehicles	$ 9,340,262	1,734,592	3,383,220	5,117,812		$ 14,458,074	$ 2,558,906	$ 11,899,168	30%	$ 4,584,716	$ 9,873,358
10.1	Certain Automobiles	$ 204,000					$ 204,000	$ -	$ 204,000	30%	$ 61,200	$ 142,800
12	Computer Software	$ 35,943,897	19,783,496	16,645,287	36,428,783		$ 72,372,680	$ 18,214,392	$ 54,158,289	100%	$ 62,480,932	$ 9,891,748
13 1	Lease # 1	$ 5,242					$ 5,242	$ -	$ 5,242		$ 5,242	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 27,927,172	300,000	0	300,000		$ 28,227,172	$ 150,000	$ 28,077,172	8%	$ 2,246,174	$ 25,980,998
42	Fibre Optic Cable	$ 10,206,455					$ 10,206,455	$ -	$ 10,206,455	12%	$ 1,224,775	$ 8,981,680
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	$ 4,110					$ 4,110	$ -	$ 4,110	45%	$ 1,850	$ 2,261
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 9,752,501					$ 9,752,501	$ -	$ 9,752,501	30%	$ 2,925,750	$ 6,826,751
47	Distribution System - post February 2005	$ 2,337,870,645	158,932,194	186,458,079	345,390,273		$ 2,683,260,918	$ 172,695,137	$ 2,510,565,782	8%	$ 215,761,909	$ 2,467,499,009
50	Data Network Infrastructure Equipment - post Mar 2007	$ 14,859,017	3,042,752	7,604,055	10,646,807		$ 25,505,824	$ 5,323,404	$ 20,182,421	55%	$ 15,282,562	$ 10,223,262
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 44,751,921					$ 44,751,921	$ -	$ 44,751,921	7%	$ 3,132,634	$ 41,619,287
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 78,152,356	17,759,158	6,175,493	23,934,651		$ 102,087,007	$ 11,967,326	$ 90,119,682	5%	$ 4,814,759	$ 97,272,248
6	Fence	$ 2,140,386	200,000	0	200,000		$ 2,340,386	$ 100,000	$ 2,240,386	10%	$ 224,039	$ 2,116,347
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,224,696,671**	**$ 205,623,444**	**$ 222,168,854**	**$ 427,792,298**	**$ -**	**$ 4,652,488,969**	**$ 213,896,149**	**$ 4,438,592,820**		**$ 372,707,534**	**$ 4,279,781,436**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

2. 2019 opening UCC balance agrees to 2018 UCC schedule prepared for 2018 audited financial statements.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2020

Class	Class Description	2020 Opening UCC Balance	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2020 CCA (new accelerated CCA rule applied)	2020 Ending UCC Balance
1	Distribution System - post 1987	$ 970,763,543	95,923	5,135,050	5,230,973		$ 975,994,516	$ 2,615,487	$ 973,379,030	4%	$ 39,140,563	$ 936,853,953
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 213,663,464					$ 213,663,464	$ -	$ 213,663,464	6%	$ 12,819,808	$ 200,843,656
8	General Office/Stores Equip	$ 23,879,498	257,889	4,052,054	4,309,943		$ 28,189,441	$ 2,154,972	$ 26,034,469	20%	$ 6,017,305	$ 22,172,136
10	Computer Hardware/ Vehicles	$ 9,873,358	0	4,724,384	4,724,384		$ 14,597,742	$ 2,362,192	$ 12,235,550	30%	$ 5,087,980	$ 9,509,762
10.1	Certain Automobiles	$ 142,800					$ 142,800	$ -	$ 142,800	30%	$ 42,840	$ 99,960
12	Computer Software	$ 9,891,748	4,093,784	33,413,194	37,506,978		$ 47,398,726	$ 18,753,489	$ 28,645,237	100%	$ 45,351,834	$ 2,046,892
13 1	Lease # 1	$ -					$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 25,980,998	0	700,000	700,000		$ 26,680,998	$ 350,000	$ 26,330,998	8%	$ 2,162,480	$ 24,518,518
42	Fibre Optic Cable	$ 8,981,680					$ 8,981,680	$ -	$ 8,981,680	12%	$ 1,077,802	$ 7,903,879
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	$ 2,261					$ 2,261	$ -	$ 2,261	45%	$ 1,017	$ 1,243
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 6,826,751					$ 6,826,751	$ -	$ 6,826,751	30%	$ 2,048,025	$ 4,778,725
47	Distribution System - post February 2005	$ 2,467,499,009	68,633,304	359,471,614	428,104,918		$ 2,895,603,927	$ 214,052,459	$ 2,681,551,468	8%	$ 243,281,847	$ 2,652,322,081
50	Data Network Infrastructure Equipment - post Mar 2007	$ 10,223,262	479,403	18,399,812	18,879,215		$ 29,102,477	$ 9,439,608	$ 19,662,870	55%	$ 20,934,475	$ 8,168,002
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 41,619,287					$ 41,619,287	$ -	$ 41,619,287	7%	$ 2,913,350	$ 38,705,936
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 97,272,248	3,722,560	23,510,403	27,232,963		$ 124,505,211	$ 13,616,482	$ 110,888,730	5%	$ 6,719,957	$ 117,785,255
6	Fence	$ 2,116,347	0	500,000	500,000		$ 2,616,347	$ 250,000	$ 2,366,347	10%	$ 286,635	$ 2,329,713
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,279,781,436**	**$ 77,282,863**	**$ 449,906,511**	**$ 527,189,374**	**$ -**	**$ 4,806,970,810**	**$ 263,594,687**	**$ 4,543,376,123**		**$ 387,885,917**	**$ 4,419,084,893**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2021

Class	Class Description	2021 Opening UCC Balance	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2021 CCA (new accelerated CCA rule applied)	2021 Ending UCC Balance
1	Distribution System - post 1987	$ 936,853,953	19,040	9,115,825	9,134,865		$ 945,988,818	$ 4,567,433	$ 941,421,385	4%	$ 38,021,488	$ 907,967,330
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 200,843,656					$ 200,843,656	$ -	$ 200,843,656	6%	$ 12,050,619	$ 188,793,036
8	General Office/Stores Equip	$ 22,172,136	41,125	5,801,020	5,842,145		$ 28,014,281	$ 2,921,073	$ 25,093,208	20%	$ 6,178,846	$ 21,835,435
10	Computer Hardware/ Vehicles	$ 9,509,762	0	8,566,595	8,566,595		$ 18,076,357	$ 4,283,298	$ 13,793,059	30%	$ 6,707,896	$ 11,368,460
10.1	Certain Automobiles	$ 99,960					$ 99,960	$ -	$ 99,960	30%	$ 29,988	$ 69,972
12	Computer Software	$ 2,046,892	19,615	33,764,995	33,784,610		$ 35,831,502	$ 16,892,305	$ 18,939,197	100%	$ 35,821,695	$ 9,808
13 1	Lease # 1	$ -					$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 24,518,518	0	100,000	100,000		$ 24,618,518	$ 50,000	$ 24,568,518	8%	$ 1,973,481	$ 22,645,037
42	Fibre Optic Cable	$ 7,903,879					$ 7,903,879	$ -	$ 7,903,879	12%	$ 948,465	$ 6,955,413
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	$ 1,243					$ 1,243	$ -	$ 1,243	45%	$ 559	$ 684
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 4,778,725					$ 4,778,725	$ -	$ 4,778,725	30%	$ 1,433,618	$ 3,345,108
47	Distribution System - post February 2005	$ 2,652,322,081	10,717,590	380,220,997	390,938,587		$ 3,043,260,668	$ 195,469,294	$ 2,847,791,374	8%	$ 258,240,990	$ 2,785,019,678
50	Data Network Infrastructure Equipment - post Mar 2007	$ 8,168,002	5,291	13,824,355	13,829,646		$ 21,997,648	$ 6,914,823	$ 15,082,825	55%	$ 15,898,949	$ 6,098,699
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 38,705,936					$ 38,705,936	$ -	$ 38,705,936	7%	$ 2,709,416	$ 35,996,521
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 117,785,255	129,433	1,731,706	1,861,139		$ 119,646,394	$ 930,570	$ 118,715,824	5%	$ 6,022,377	$ 113,624,017
6	Fence	$ 2,329,713	0	200,000	200,000		$ 2,529,713	$ 100,000	$ 2,429,713	10%	$ 262,971	$ 2,266,741
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,419,084,893**	**$ 10,932,094**	**$ 453,325,493**	**$ 464,257,587**	**$ -**	**$ 4,883,342,480**	**$ 232,128,794**	**$ 4,651,213,686**		**$ 386,301,358**	**$ 4,497,041,121**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2022

Class	Class Description	2022 Opening UCC Balance	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2022 CCA (new accelerated CCA rule applied)	2022 Ending UCC Balance
1	Distribution System - post 1987	$ 907,967,330	6,750	36,947,528	36,954,278		$ 944,921,608	$ 18,477,139	$ 926,444,469	4%	$ 38,535,680	$ 906,385,928
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 188,793,036					$ 188,793,036	$ -	$ 188,793,036	6%	$ 11,327,582	$ 177,465,454
8	General Office/Stores Equip	$ 21,835,435	24,694	15,506,865	15,531,559		$ 37,366,994	$ 7,765,780	$ 29,601,215	20%	$ 9,021,616	$ 28,345,378
10	Computer Hardware/ Vehicles	$ 11,368,460	0	8,160,248	8,160,248		$ 19,528,708	$ 4,080,124	$ 15,448,584	30%	$ 7,082,650	$ 12,446,059
10.1	Certain Automobiles	$ 69,972					$ 69,972	$ -	$ 69,972	30%	$ 20,992	$ 48,980
12	Computer Software	$ 9,808	7,513	58,358,402	58,365,915		$ 58,375,723	$ 29,182,958	$ 29,192,765	100%	$ 58,371,966	$ 3,757
13 1	Lease # 1	$ -					$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 22,645,037	0	5,000,000	5,000,000		$ 27,645,037	$ 2,500,000	$ 25,145,037	8%	$ 2,411,603	$ 25,233,434
42	Fibre Optic Cable	$ 6,955,413					$ 6,955,413	$ -	$ 6,955,413	12%	$ 834,650	$ 6,120,764
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	$ 684					$ 684	$ -	$ 684	45%	$ 308	$ 376
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 3,345,108					$ 3,345,108	$ -	$ 3,345,108	30%	$ 1,003,532	$ 2,341,575
47	Distribution System - post February 2005	$ 2,785,019,678	5,398,606	419,726,467	425,125,073		$ 3,210,144,751	$ 212,562,537	$ 2,997,582,214	8%	$ 273,384,695	$ 2,936,760,056
50	Data Network Infrastructure Equipment - post Mar 2007	$ 6,098,699	7,775	18,703,697	18,711,472		$ 24,810,171	$ 9,355,736	$ 15,454,435	55%	$ 18,786,973	$ 6,023,198
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 35,996,521					$ 35,996,521	$ -	$ 35,996,521	7%	$ 2,519,756	$ 33,476,764
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 113,624,017	18,490	3,770,206	3,788,696		$ 117,412,713	$ 1,894,348	$ 115,518,365	5%	$ 5,964,429	$ 111,448,285
6	Fence	$ 2,266,741	0	1,100,000	1,100,000		$ 3,366,741	$ 550,000	$ 2,816,741	10%	$ 391,674	$ 2,975,067
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,497,041,121**	**$ 5,463,828**	**$ 567,273,413**	**$ 572,737,241**	**$ -**	**$ 5,069,778,362**	**$ 286,368,621**	**$ 4,783,409,742**		**$ 429,658,104**	**$ 4,640,120,258**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2023

Class	Class Description	2023 Opening UCC Balance	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2023 CCA (new accelerated CCA rule applied)	2023 Ending UCC Balance
1	Distribution System - post 1987	$ 906,385,928	1,508	10,856,489	10,857,997		$ 917,243,925	$ 5,428,999	$ 911,814,926	4%	$ 36,906,857	$ 880,337,068
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 177,465,454					$ 177,465,454	$ -	$ 177,465,454	6%	$ 10,647,927	$ 166,817,527
8	General Office/Stores Equip	$ 28,345,378	4,356	4,193,114	4,197,470		$ 32,542,848	$ 2,098,735	$ 30,444,113	20%	$ 6,927,445	$ 25,615,403
10	Computer Hardware/ Vehicles	$ 12,446,059	0	8,757,855	8,757,855		$ 21,203,914	$ 4,378,928	$ 16,824,986	30%	$ 7,674,852	$ 13,529,061
10.1	Certain Automobiles	$ 48,980					$ 48,980	$ -	$ 48,980	30%	$ 14,694	$ 34,286
12	Computer Software	$ 3,757	3,422	38,195,622	38,199,044		$ 38,202,801	$ 19,099,522	$ 19,103,279	100%	$ 38,201,090	$ 1,711
13 1	Lease # 1	$ -					$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 25,233,434	0	100,000	100,000		$ 25,333,434	$ 50,000	$ 25,283,434	8%	$ 2,030,675	$ 23,302,759
42	Fibre Optic Cable	$ 6,120,764					$ 6,120,764	$ -	$ 6,120,764	12%	$ 734,492	$ 5,386,272
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	$ 376					$ 376	$ -	$ 376	45%	$ 169	$ 207
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 2,341,575					$ 2,341,575	$ -	$ 2,341,575	30%	$ 702,473	$ 1,639,103
47	Distribution System - post February 2005	$ 2,936,760,056	1,371,044	455,668,212	457,039,256		$ 3,393,799,312	$ 228,519,628	$ 3,165,279,684	8%	$ 289,675,832	$ 3,104,123,481
50	Data Network Infrastructure Equipment - post Mar 2007	$ 6,023,198	904	17,118,136	17,119,040		$ 23,142,238	$ 8,559,520	$ 14,582,718	55%	$ 17,435,470	$ 5,706,769
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 33,476,764					$ 33,476,764	$ -	$ 33,476,764	7%	$ 2,343,374	$ 31,133,391
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 111,448,285	0	35,620,276	35,620,276		$ 147,068,561	$ 17,810,138	$ 129,258,423	5%	$ 8,243,935	$ 138,824,626
6	Fence	$ 2,975,067	0	100,000	100,000		$ 3,075,067	$ 50,000	$ 3,025,067	10%	$ 312,507	$ 2,762,561
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,640,120,258**	**$ 1,381,234**	**$ 570,609,704**	**$ 571,990,938**	**$ -**	**$ 5,212,111,196**	**$ 285,995,469**	**$ 4,926,115,727**		**$ 421,851,790**	**$ 4,790,259,406**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2024

Class	Class Description	2024 Opening UCC Balance	Additions (acquired before November 21, 2018)	Additions (acquired after November 20, 2018)	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2024 CCA (new accelerated CCA rule applied)	2024 Ending UCC Balance
1	Distribution System - post 1987	$ 880,337,068	380	11,471,226	11,471,606		$ 891,808,674	$ 5,735,803	$ 886,072,871	4%	$ 35,672,339	$ 856,136,335
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -					$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 166,817,527					$ 166,817,527	$ -	$ 166,817,527	6%	$ 10,009,052	$ 156,808,475
8	General Office/Stores Equip	$ 25,615,403	1,491	5,213,377	5,214,868		$ 30,830,271	$ 2,607,434	$ 28,222,837	20%	$ 6,165,905	$ 24,664,366
10	Computer Hardware/ Vehicles	$ 13,529,061	0	9,080,788	9,080,788		$ 22,609,849	$ 4,540,394	$ 18,069,455	30%	$ 6,782,955	$ 15,826,894
10.1	Certain Automobiles	$ 34,286					$ 34,286	$ -	$ 34,286	30%	$ 10,286	$ 24,000
12	Computer Software	$ 1,711	1,546	38,579,638	38,581,184		$ 38,582,895	$ 19,290,592	$ 19,292,303	100%	$ 38,582,122	$ 773
13 1	Lease # 1	$ -					$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -					$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -					$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -					$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -					$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 23,302,759	0	100,000	100,000		$ 23,402,759	$ 50,000	$ 23,352,759	8%	$ 1,872,221	$ 21,530,539
42	Fibre Optic Cable	$ 5,386,272					$ 5,386,272	$ -	$ 5,386,272	12%	$ 646,353	$ 4,739,919
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	$ 207					$ 207	$ -	$ 207	45%	$ 93	$ 114
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 1,639,103					$ 1,639,103	$ -	$ 1,639,103	30%	$ 491,731	$ 1,147,372
47	Distribution System - post February 2005	$ 3,104,123,481	490,863	474,265,595	474,756,458		$ 3,578,879,939	$ 237,378,229	$ 3,341,501,710	8%	$ 286,290,761	$ 3,292,589,178
50	Data Network Infrastructure Equipment - post Mar 2007	$ 5,706,769	405	17,967,694	17,968,099		$ 23,674,868	$ 8,984,050	$ 14,690,818	55%	$ 13,021,066	$ 10,653,802
52	Computer Hardware and system software	$ -					$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182					$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 31,133,391					$ 31,133,391	$ -	$ 31,133,391	7%	$ 2,179,337	$ 28,954,054
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 138,824,626	0	9,124,309	9,124,309		$ 147,948,935	$ 4,562,155	$ 143,386,780	5%	$ 7,397,447	$ 140,551,488
6	Fence	$ 2,762,561	0	100,000	100,000		$ 2,862,561	$ 50,000	$ 2,812,561	10%	$ 286,256	$ 2,576,304
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,790,259,406**	**$ 494,685**	**$ 565,902,627**	**$ 566,397,312**	**$ -**	**$ 5,356,656,718**	**$ 283,198,656**	**$ 5,073,458,062**		**$ 409,407,923**	**$ 4,947,248,795**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

	T2 S1 line #	2019 Bridge Year Taxable Income	2020 Test Year Taxable Income	2021 Test Year Taxable Income	2022 Test Year Taxable Income	2023 Test Year Taxable Income	2024 Test Year Taxable Income
Net Income Before Taxes		**164,525,122**	**160,657,625**	**170,789,286**	**179,506,254**	**189,690,836**	**199,232,627**
Additions:							
Amortization of tangible assets 2-4 ADJUSTED ACCOUNTING DATA P489	104	245,421,228	265,539,781	281,534,085	292,284,881	314,013,618	327,126,489
Non-deductible club dues and fees	120	334,453	334,453	334,453	334,453	334,453	334,453
Non-deductible meals and entertainment expense	121	227,915	227,915	227,915	227,915	227,915	227,915
Reserves from financial statements- balance at end of year	126	278,844,000	283,172,000	283,172,000	283,172,000	283,172,000	283,172,000
Financing fees deducted in books	216	1,173,682	1,125,064	1,125,064	1,125,064	1,125,064	1,125,064
Capital Contributions Received (ITA 12(1)(x))		79,065,880	139,706,986	139,706,986	139,706,986	139,706,986	139,706,986
Deferred Revenue (ITA 12(1)(a))		1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Interest expensed on capital leases	290	26,379	20,214	20,214	20,214	20,214	20,214
Prior Year Investment Tax Credits received		2,736,000	2,736,000	2,736,000	2,736,000	2,736,000	2,736,000
Total Additions		**608,929,537**	**693,962,413**	**709,956,717**	**720,707,513**	**742,436,250**	**755,549,121**
Deductions:							
Gain on disposal of assets per financial statements	401	0	0	0	0	0	0
Capital cost allowance from Schedule 8	403	343,652,350	340,782,336	354,833,510	380,208,180	399,784,220	405,349,444
Reserves from financial statements - balance at beginning of year	414	274,566,000	278,844,000	278,844,000	278,844,000	278,844,000	278,844,000
Financing Fees for Tax ITA S.20(1)(e) and (e.1)		1,681,277	1,453,417	1,453,417	1,453,417	1,453,417	1,453,417
ARO Payments - Deductible for Tax when Paid		74,232	75,717	75,717	75,717	75,717	75,717
ITA 13(7.4) Election - Capital Contributions Received		79,065,880	139,706,986	139,706,986	139,706,986	139,706,986	139,706,986
Deferred Revenue - ITA 20(1)(m) reserve		1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Land Lease payment capitalized for accounting		89,423	89,423	89,423	89,423	89,423	89,423
Other Post-Employment Benefits adjustment - change in balance with no Income Statement Impact		149,000	193,000	193,000	193,000	193,000	193,000
Other Post-Employment Benefits adjustment - current year capitalized portion with no Income Statement Impact		5,855,808	5,974,528	5,974,528	5,974,528	5,974,528	5,974,528
Lease inducement Book Amortization credit to income		54,792	54,792	54,792	54,792	54,792	54,792
Capital lease payments	391	299,000	310,176	310,176	310,176	310,176	310,176
Total Deductions		**706,587,762**	**768,584,375**	**782,635,549**	**808,010,219**	**827,586,259**	**833,151,483**
NET INCOME FOR TAX PURPOSES		**66,866,897**	**86,035,663**	**98,110,454**	**92,203,548**	**104,540,827**	**121,630,265**
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		**66,866,897**	**86,035,663**	**98,110,454**	**92,203,548**	**104,540,827**	**121,630,265**

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

	T2 S1 line #	2019 Bridge Year Taxable Income	2020 Test Year Taxable Income	2021 Test Year Taxable Income	2022 Test Year Taxable Income	2023 Test Year Taxable Income	2024 Test Year Taxable Income
Total Ontario income taxes before small business deduction	**11.50%**	7,689,693	9,894,101	11,282,702	10,603,408	12,022,195	13,987,480
Ontario Small Business Deduction		0	0	0	0	0	0
Total Ontario income taxes		**7,689,693**	**9,894,101**	**11,282,702**	**10,603,408**	**12,022,195**	**13,987,480**
Effective Ontario tax rate		11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Federal tax rate		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Combined tax rate		**26.50%**	**26.50%**	**26.50%**	**26.50%**	**26.50%**	**26.50%**

Total Income taxes		**17,719,728**	**22,799,451**	**25,999,270**	**24,433,940**	**27,703,319**	**32,232,020**
Investment Tax credits		-1,478,000	-1,478,000	-1,478,000	-1,478,000	-1,478,000	-1,478,000
Miscellaneous Tax credits		-1,258,000	-1,258,000	-1,258,000	-1,258,000	-1,258,000	-1,258,000
Total tax credits		**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**	**-2,736,000**
Corporate PILs/Income Tax Provision for Test Year		**14,983,728**	**20,063,451**	**23,263,270**	**21,697,940**	**24,967,319**	**29,496,020**
Corporate PILs/Income Tax Provision Gross Up [1]	**73.50%**	5,402,296	7,233,761	8,387,438	7,823,067	9,001,823	10,634,620
Income Tax (grossed-up) before tax credits reclass to OM&A		**20,386,024**	**27,297,212**	**31,650,708**	**29,521,007**	**33,969,142**	**40,130,640**
Tax credits reclass to OM&A		**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**	**1,875,113**
Income Tax (grossed-up) after tax credits reclass to OM&A		**22,261,137**	**29,172,325**	**33,525,821**	**31,396,120**	**35,844,255**	**42,005,753**

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

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2019

Class	Class Description	2019 Opening UCC Balance[2]	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2019 CCA (existing CCA rule)	2019 Ending UCC Balance
1	Distribution System - post 1987	$ 1,008,853,279	2,328,623		$ 1,011,181,902	$ 1,164,312	$ 1,010,017,591	4%	$ 40,400,704	$ 970,781,198
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 227,301,557			$ 227,301,557	$ -	$ 227,301,557	6%	$ 13,638,093	$ 213,663,464
8	General Office/Stores Equip	$ 26,338,689	3,445,349		$ 29,784,038	$ 1,722,675	$ 28,061,364	20%	$ 5,612,273	$ 24,171,765
10	Computer Hardware/ Vehicles	$ 9,340,262	5,117,812		$ 14,458,074	$ 2,558,906	$ 11,899,168	30%	$ 3,569,750	$ 10,888,324
10.1	Certain Automobiles	$ 204,000			$ 204,000	$ -	$ 204,000	30%	$ 61,200	$ 142,800
12	Computer Software	$ 35,943,897	36,428,783		$ 72,372,680	$ 18,214,392	$ 54,158,289	100%	$ 54,158,289	$ 18,214,392
13 1	Lease # 1	$ 5,242			$ 5,242	$ -	$ 5,242		$ 5,242	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 27,927,172	300,000		$ 28,227,172	$ 150,000	$ 28,077,172	8%	$ 2,246,174	$ 25,980,998
42	Fibre Optic Cable	$ 10,206,455			$ 10,206,455	$ -	$ 10,206,455	12%	$ 1,224,775	$ 8,981,680
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	$ 4,110			$ 4,110	$ -	$ 4,110	45%	$ 1,850	$ 2,261
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 9,752,501			$ 9,752,501	$ -	$ 9,752,501	30%	$ 2,925,750	$ 6,826,751
47	Distribution System - post February 2005	$ 2,337,870,645	345,390,273		$ 2,683,260,918	$ 172,695,137	$ 2,510,565,782	8%	$ 200,845,263	$ 2,482,415,655
50	Data Network Infrastructure Equipment - post Mar 2007	$ 14,859,017	10,646,807		$ 25,505,824	$ 5,323,404	$ 20,182,421	55%	$ 11,100,331	$ 14,405,493
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 44,751,921			$ 44,751,921	$ -	$ 44,751,921	7%	$ 3,132,634	$ 41,619,287
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 78,152,356	23,934,651		$ 102,087,007	$ 11,967,326	$ 90,119,682	5%	$ 4,505,984	$ 97,581,023
6	Fence	$ 2,140,386	200,000		$ 2,340,386	$ 100,000	$ 2,240,386	10%	$ 224,039	$ 2,116,347
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,224,696,671**	**$ 427,792,298**	**$ -**	**$ 4,652,488,969**	**$ 213,896,149**	**$ 4,438,592,820**		**$ 343,652,350**	**$ 4,308,836,619**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

2. 2019 opening UCC balance agrees to 2018 UCC schedule prepared for 2018 audited financial statements.

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2020

Class	Class Description	2020 Opening UCC Balance	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2020 CCA (existing CCA rule)	2020 Ending UCC Balance
1	Distribution System - post 1987	$ 970,781,198	5,230,973		$ 976,012,171	$ 2,615,487	$ 973,396,685	4%	$ 38,935,867	$ 937,076,304
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 213,663,464			$ 213,663,464	$ -	$ 213,663,464	6%	$ 12,819,808	$ 200,843,656
8	General Office/Stores Equip	$ 24,171,765	4,309,943		$ 28,481,708	$ 2,154,972	$ 26,326,737	20%	$ 5,265,347	$ 23,216,361
10	Computer Hardware/ Vehicles	$ 10,888,324	4,724,384		$ 15,612,708	$ 2,362,192	$ 13,250,516	30%	$ 3,975,155	$ 11,637,553
10.1	Certain Automobiles	$ 142,800			$ 142,800	$ -	$ 142,800	30%	$ 42,840	$ 99,960
12	Computer Software	$ 18,214,392	37,506,978		$ 55,721,370	$ 18,753,489	$ 36,967,881	100%	$ 36,967,881	$ 18,753,489
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 25,980,998	700,000		$ 26,680,998	$ 350,000	$ 26,330,998	8%	$ 2,106,480	$ 24,574,518
42	Fibre Optic Cable	$ 8,981,680			$ 8,981,680	$ -	$ 8,981,680	12%	$ 1,077,802	$ 7,903,879
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	$ 2,261			$ 2,261	$ -	$ 2,261	45%	$ 1,017	$ 1,243
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 6,826,751			$ 6,826,751	$ -	$ 6,826,751	30%	$ 2,048,025	$ 4,778,725
47	Distribution System - post February 2005	$ 2,482,415,655	428,104,918		$ 2,910,520,573	$ 214,052,459	$ 2,696,468,114	8%	$ 215,717,449	$ 2,694,803,124
50	Data Network Infrastructure Equipment - post Mar 2007	$ 14,405,493	18,879,215		$ 33,284,708	$ 9,439,608	$ 23,845,100	55%	$ 13,114,805	$ 20,169,903
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 41,619,287			$ 41,619,287	$ -	$ 41,619,287	7%	$ 2,913,350	$ 38,705,936
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 97,581,023	27,232,963		$ 124,813,986	$ 13,616,482	$ 111,197,504	5%	$ 5,559,875	$ 119,254,111
6	Fence	$ 2,116,347	500,000		$ 2,616,347	$ 250,000	$ 2,366,347	10%	$ 236,635	$ 2,379,713
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,308,836,619**	**$ 527,189,374**	**$ -**	**$ 4,836,025,993**	**$ 263,594,687**	**$ 4,572,431,306**		**$ 340,782,336**	**$ 4,495,243,657**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2021

Class	Class Description	2021 Opening UCC Balance	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2021 CCA (existing CCA rule)	2021 Ending UCC Balance
1	Distribution System - post 1987	$ 937,076,304	9,134,865		$ 946,211,169	$ 4,567,433	$ 941,643,736	4%	$ 37,665,749	$ 908,545,420
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 200,843,656			$ 200,843,656	$ -	$ 200,843,656	6%	$ 12,050,619	$ 188,793,036
8	General Office/Stores Equip	$ 23,216,361	5,842,145		$ 29,058,506	$ 2,921,073	$ 26,137,433	20%	$ 5,227,487	$ 23,831,019
10	Computer Hardware/ Vehicles	$ 11,637,553	8,566,595		$ 20,204,148	$ 4,283,298	$ 15,920,850	30%	$ 4,776,255	$ 15,427,893
10.1	Certain Automobiles	$ 99,960			$ 99,960	$ -	$ 99,960	30%	$ 29,988	$ 69,972
12	Computer Software	$ 18,753,489	33,784,610		$ 52,538,099	$ 16,892,305	$ 35,645,794	100%	$ 35,645,794	$ 16,892,305
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 24,574,518	100,000		$ 24,674,518	$ 50,000	$ 24,624,518	8%	$ 1,969,961	$ 22,704,557
42	Fibre Optic Cable	$ 7,903,879			$ 7,903,879	$ -	$ 7,903,879	12%	$ 948,465	$ 6,955,413
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	$ 1,243			$ 1,243	$ -	$ 1,243	45%	$ 559	$ 684
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 4,778,725			$ 4,778,725	$ -	$ 4,778,725	30%	$ 1,433,618	$ 3,345,108
47	Distribution System - post February 2005	$ 2,694,803,124	390,938,587		$ 3,085,741,711	$ 195,469,294	$ 2,890,272,418	8%	$ 231,221,793	$ 2,854,519,918
50	Data Network Infrastructure Equipment - post Mar 2007	$ 20,169,903	13,829,646		$ 33,999,549	$ 6,914,823	$ 27,084,726	55%	$ 14,896,599	$ 19,102,950
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 38,705,936			$ 38,705,936	$ -	$ 38,705,936	7%	$ 2,709,416	$ 35,996,521
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 119,254,111	1,861,139		$ 121,115,250	$ 930,570	$ 120,184,680	5%	$ 6,009,234	$ 115,106,016
6	Fence	$ 2,379,713	200,000		$ 2,579,713	$ 100,000	$ 2,479,713	10%	$ 247,971	$ 2,331,741
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,495,243,657**	**$ 464,257,587**	**$ -**	**$ 4,959,501,244**	**$ 232,128,794**	**$ 4,727,372,451**		**$ 354,833,510**	**$ 4,604,667,734**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2022

Class	Class Description	2022 Opening UCC Balance	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2022 CCA (existing CCA rule)	2022 Ending UCC Balance
1	Distribution System - post 1987	$ 908,545,420	36,954,278		$ 945,499,698	$ 18,477,139	$ 927,022,559	4%	$ 37,080,902	$ 908,418,795
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 188,793,036			$ 188,793,036	$ -	$ 188,793,036	6%	$ 11,327,582	$ 177,465,454
8	General Office/Stores Equip	$ 23,831,019	15,531,559		$ 39,362,578	$ 7,765,780	$ 31,596,799	20%	$ 6,319,360	$ 33,043,219
10	Computer Hardware/ Vehicles	$ 15,427,893	8,160,248		$ 23,588,141	$ 4,080,124	$ 19,508,017	30%	$ 5,852,405	$ 17,735,736
10.1	Certain Automobiles	$ 69,972			$ 69,972	$ -	$ 69,972	30%	$ 20,992	$ 48,980
12	Computer Software	$ 16,892,305	58,365,915		$ 75,258,220	$ 29,182,958	$ 46,075,263	100%	$ 46,075,263	$ 29,182,958
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 22,704,557	5,000,000		$ 27,704,557	$ 2,500,000	$ 25,204,557	8%	$ 2,016,365	$ 25,688,192
42	Fibre Optic Cable	$ 6,955,413			$ 6,955,413	$ -	$ 6,955,413	12%	$ 834,650	$ 6,120,764
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	$ 684			$ 684	$ -	$ 684	45%	$ 308	$ 376
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 3,345,108			$ 3,345,108	$ -	$ 3,345,108	30%	$ 1,003,532	$ 2,341,575
47	Distribution System - post February 2005	$ 2,854,519,918	425,125,073		$ 3,279,644,991	$ 212,562,537	$ 3,067,082,454	8%	$ 245,366,596	$ 3,034,278,395
50	Data Network Infrastructure Equipment - post Mar 2007	$ 19,102,950	18,711,472		$ 37,814,422	$ 9,355,736	$ 28,458,686	55%	$ 15,652,277	$ 22,162,144
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 35,996,521			$ 35,996,521	$ -	$ 35,996,521	7%	$ 2,519,756	$ 33,476,764
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 115,106,016	3,788,696		$ 118,894,712	$ 1,894,348	$ 117,000,364	5%	$ 5,850,018	$ 113,044,694
6	Fence	$ 2,331,741	1,100,000		$ 3,431,741	$ 550,000	$ 2,881,741	10%	$ 288,174	$ 3,143,567
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,604,667,734**	**$ 572,737,241**	**$ -**	**$ 5,177,404,975**	**$ 286,368,621**	**$ 4,891,036,355**		**$ 380,208,180**	**$ 4,797,196,795**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2023

Class	Class Description		2023 Opening UCC Balance	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2023 CCA (Existing CCA rule)		2023 Ending UCC Balance
1	Distribution System - post 1987		$ 908,418,795	10,857,997		$ 919,276,792	$ 5,428,999	$ 913,847,794	4%	$ 36,553,912		$ 882,722,880
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election		$ -			$ -	$ -	$ -	6%	$ -		$ -
2	Distribution System - pre 1988		$ 177,465,454			$ 177,465,454	$ -	$ 177,465,454	6%	$ 10,647,927		$ 166,817,527
8	General Office/Stores Equip		$ 33,043,219	4,197,470		$ 37,240,689	$ 2,098,735	$ 35,141,954	20%	$ 7,028,391		$ 30,212,298
10	Computer Hardware/ Vehicles		$ 17,735,736	8,757,855		$ 26,493,591	$ 4,378,928	$ 22,114,663	30%	$ 6,634,399		$ 19,859,192
10.1	Certain Automobiles		$ 48,980			$ 48,980	$ -	$ 48,980	30%	$ 14,694		$ 34,286
12	Computer Software		$ 29,182,958	38,199,044		$ 67,382,002	$ 19,099,522	$ 48,282,480	100%	$ 48,282,480		$ 19,099,522
13 1	Lease # 1		$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2		$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3		$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4		$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise		$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		$ 25,688,192	100,000		$ 25,788,192	$ 50,000	$ 25,738,192	8%	$ 2,059,055		$ 23,729,137
42	Fibre Optic Cable		$ 6,120,764			$ 6,120,764	$ -	$ 6,120,764	12%	$ 734,492		$ 5,386,272
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		$ 376			$ 376	$ -	$ 376	45%	$ 169		$ 207
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		$ 2,341,575			$ 2,341,575	$ -	$ 2,341,575	30%	$ 702,473		$ 1,639,103
47	Distribution System - post February 2005		$ 3,034,278,395	457,039,256		$ 3,491,317,651	$ 228,519,628	$ 3,262,798,023	8%	$ 261,023,842		$ 3,230,293,809
50	Data Network Infrastructure Equipment - post Mar 2007		$ 22,162,144	17,119,040		$ 39,281,184	$ 8,559,520	$ 30,721,664	55%	$ 16,896,915		$ 22,384,269
52	Computer Hardware and system software		$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP		$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -		$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]		$ 33,476,764			$ 33,476,764	$ -	$ 33,476,764	7%	$ 2,343,374		$ 31,133,391
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]		$ 113,044,694	35,620,276		$ 148,664,970	$ 17,810,138	$ 130,854,832	5%	$ 6,542,742		$ 142,122,228
6	Fence		$ 3,143,567	100,000		$ 3,243,567	$ 50,000	$ 3,193,567	10%	$ 319,357		$ 2,924,211
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 4,797,196,795	$ 571,990,938	$ -	$ 5,369,187,733	$ 285,995,469	$ 5,083,192,264		$ 399,784,220		$ 4,969,403,513

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 8 CCA - 2024

Class	Class Description	2024 Opening UCC Balance	Total Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2024 CCA (Existing CCA rule)	2024 Ending UCC Balance
1	Distribution System - post 1987	$ 882,722,880	11,471,606		$ 894,194,486	$ 5,735,803	$ 888,458,683	4%	$ 35,538,347	$ 858,656,139
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 166,817,527			$ 166,817,527	$ -	$ 166,817,527	6%	$ 10,009,052	$ 156,808,475
8	General Office/Stores Equip	$ 30,212,298	5,214,868		$ 35,427,166	$ 2,607,434	$ 32,819,732	20%	$ 6,563,946	$ 28,863,219
10	Computer Hardware/ Vehicles	$ 19,859,192	9,080,788		$ 28,939,980	$ 4,540,394	$ 24,399,586	30%	$ 7,319,876	$ 21,620,104
10.1	Certain Automobiles	$ 34,286			$ 34,286	$ -	$ 34,286	30%	$ 10,286	$ 24,000
12	Computer Software	$ 19,099,522	38,581,184		$ 57,680,706	$ 19,290,592	$ 38,390,114	100%	$ 38,390,114	$ 19,290,592
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 23,729,137	100,000		$ 23,829,137	$ 50,000	$ 23,779,137	8%	$ 1,902,331	$ 21,926,806
42	Fibre Optic Cable	$ 5,386,272			$ 5,386,272	$ -	$ 5,386,272	12%	$ 646,353	$ 4,739,919
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	$ 207			$ 207	$ -	$ 207	45%	$ 93	$ 114
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 1,639,103			$ 1,639,103	$ -	$ 1,639,103	30%	$ 491,731	$ 1,147,372
47	Distribution System - post February 2005	$ 3,230,293,809	474,756,458		$ 3,705,050,267	$ 237,378,229	$ 3,467,672,038	8%	$ 277,413,763	$ 3,427,636,504
50	Data Network Infrastructure Equipment - post Mar 2007	$ 22,384,269	17,968,099		$ 40,352,368	$ 8,984,050	$ 31,368,319	55%	$ 17,252,575	$ 23,099,793
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 391,045,182			$ 391,045,182	$ -	$ 391,045,182	0%	$ -	$ 391,045,182
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	$ 31,133,391			$ 31,133,391	$ -	$ 31,133,391	7%	$ 2,179,337	$ 28,954,054
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]	$ 142,122,228	9,124,309		$ 151,246,537	$ 4,562,155	$ 146,684,382	5%	$ 7,334,219	$ 143,912,318
6	Fence	$ 2,924,211	100,000		$ 3,024,211	$ 50,000	$ 2,974,211	10%	$ 297,421	$ 2,726,789
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	**$ 4,969,403,513**	**$ 566,397,312**	**$ -**	**$ 5,535,800,825**	**$ 283,198,656**	**$ 5,252,602,169**		**$ 405,349,444**	**$ 5,130,451,381**

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 189:

Reference(s): **Exhibit U, Tab 8, Schedule 1, p. 3 and Appendix A**

Please explain what changes are reflected in the updated bill impact tables.

RESPONSE:

The referenced 2020-2024 bill impacts reflect changes to:

- Base distribution rates due to updated load and customer forecast;
- Group 2 Rate Riders (CRRRVA, External Driven Capital, OPEB cash vs accrual, Derecognition, Deferred Gain on disposals, Operations Consolidation Plan Sharing Variance, Excess Expansion Deposits) due to updated balances;
- Group 1 DVA rate riders due to inclusion of RSVA balances; and
- 2019 rates due to OEB approval of these rates.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 190:

Reference(s): **Exhibit U, Tab 9, Schedule 1**
DVA Continuity Schedule (excel)

<u>Preamble:</u>

Toronto Hydro submitted a Deferral and Variance Account (DVA) continuity schedule that is different than the OEB issued model. This makes the review of the model very difficult as it is not clear if formulas were changed and whether the data input is consistent across all other schedules of the model. OEB staff is aware that an OEB issued DVA continuity model is not yet available for 2020 rates.

a) To facilitate a more timely review, please complete the enclosed OEB DVA continuity model that has been customized to allow for disposition of audited 2018 DVA balances.

RESPONSE:

Due to complexity involved adjusting the OEB model to fit Toronto Hydro's specifications, the utility used its own DVA continuity schedule model as part of the current proceeding. Please refer to Appendix A of this response for the completed model with 2018 balances and Appendix B for the 2019 DVA balances.

Toronto Hydro consolidated the DVA continuity schedule model into one workbook. For ease of reference, Toronto Hydro also included in the model (under Tab 2B) the following three accounts, which were not part of the original DVA continuity schedule:

- Excess Expansion Deposits (Exhibit 9, Tab 1, Schedule 1);
- AR Credits (Exhibit 8, Tab 1, Schedule 1); and,
- Amounts related to the sale of property at 50/60 Eglinton Avenue (Exhibit 8, Tab 1, Schedule 1).

2020 Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2017, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

		2012									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550					$0					$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580					$0					$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584					$0					$0
RSVA - Retail Transmission Connection Charge	1586					$0					$0
RSVA - Power (excluding Global Adjustment)[12]	1588					$0					$0
RSVA - Global Adjustment [12]	1589					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

		2013									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551					$0	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB

2020 Deferral/Variance A

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$109,729			$109,729	$0	-$261,355			-$261,355
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580		$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580		$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

2020 Deferral/Variance A

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

2016

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 1 Accounts											
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$54,487	$966			-$53,521
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712

2017

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 1 Accounts											
LV Variance Account	1550	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$81,084,945	$56,920,194	$94,368,616		$43,636,523	$4,942,712	$274,057	$4,812,604		$404,166
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0				$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$11,436,118	$34,580,526	$23,676,474	$0	-$532,067	$2,108,037	-$600,683	$2,182,727	-$993,537	-$1,668,911
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$92,521,064	-$22,339,668	-$70,692,141	$0	-$44,168,591	-$2,834,676	-$874,740	-$2,629,877	-$993,537	-$2,073,076
RSVA - Global Adjustment 12	**1589**	$81,084,945	$56,920,194	$94,368,616	$0	$43,636,523	$4,942,712	$274,057	$4,812,604	$0	$404,166

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

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This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	2019 Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 1 Accounts															
LV Variance Account	1550	$706,353	$320,000	$312,025	$0	$714,328	$8,068	$10,579	$5,861	$0	$12,787	$394,328	$9,276	$320,000	$3,511
Smart Metering Entity Charge Variance Account	1551	-$492,958	-$727,042	-$379,776	$0	-$840,224	$3,001	-$1,169	$13,241	$0	-$11,409	-$113,182	-$19,076	-$727,042	$7,667
RSVA - Wholesale Market Service Charge[9]	1580	-$51,235,576	-$4,206,092	-$26,035,862	$0	-$29,405,806	-$602,984	-$497,277	-$498,414	$0	-$601,847	-$25,199,715	-$556,274	-$4,206,092	-$45,573
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$2,059,564	-$570,685	$1,535,334	$0	-$46,455	-$50,215	$6,908	-$52,680	$0	$9,373	$524,231	$11,862	-$570,686	-$2,489
RSVA - Retail Transmission Network Charge	1584	-$8,318,223	$8,947,315	-$16,414,402	$0	$17,043,495	-$153,109	$200,783	-$205,715	$0	$253,388	$8,096,178	$197,730	$8,947,316	$55,658
RSVA - Retail Transmission Connection Charge	1586	-$21,616,765	$17,363,768	-$29,949,890	$0	$25,696,892	-$397,823	$277,670	-$446,320	$0	$326,167	$8,333,125	$197,868	$17,363,768	$128,299
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,241,858	-$5,431,100	-$4,904,742		-$8,768,216	-$112,749	-$152,662	-$98,572	$0	-$166,840	-$3,337,116	-$73,995	-$5,431,100	-$92,845
RSVA - Global Adjustment [12]	1589	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,587	$493,758	$6,554,025	$341,438	-$23,898,523	$152,320
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	$0	$0	$0	-$0	$0	$0	$0	-$0	$0	$0	$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$0	$0	$0	$0	-$0	-$0	$0	$0	$0	-$0	$0	$0	-$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	-$0	$0	$0	$0	-$0	$0	$0	$0	$0	$0	$0	$0	-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	-$0	$0	$0	$0	-$0	-$88	$0	$0	$0	-$88	$0	$0	-$0	-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$40,179,133	-$14,888,043	$0	$0	$25,291,090	-$909,242	-$91,080	$0	$0	-$1,000,322	$0	$0	$25,291,090	-$1,000,322
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$2,791,740	-$2,695,385	$0	$0	$96,355	$142,065	-$35,114	$0	$0	$106,951	$0	$0	$96,355	$106,951
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	-$6,348,433	$0	$0	-$6,348,433	$0	-$711,779	$0	$0	-$711,779	$0	$0	-$6,348,433	-$711,779
Not to be disposed of until a year after rate rider has expired and that balanc															
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$532,067	-$32,134,222	-$89,120,985	-$50,366,169	$6,088,526	-$1,668,911	-$718,751	-$1,225,388	-$127,587	-$1,289,860	-$4,748,127	$108,829	$10,836,653	-$1,398,689
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$44,168,591	-$8,235,698	-$75,837,313	$0	$23,433,025	-$2,073,076	-$993,140	-$1,282,599	$0	-$1,783,618	-$11,302,151	-$232,609	$34,735,176	-$1,551,009
RSVA - Global Adjustment 12	**1589**	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,587	$493,758	$6,554,025	$341,438	-$23,898,523	$152,320

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

2020 Deferral/Variance A

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2017), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 6 will be generated and applicants must complete the information pertaining to Class A customers.

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

		Projected Interest on Dec-31-18 Balances					2.1.7 RRR	
Account Descriptions	Account Number	Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest		Total Claim	As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 1 Accounts								
LV Variance Account	1550	$7,192	$0	$10,703		$330,703.40	$727,114	-$1
Smart Metering Entity Charge Variance Account	1551	-$18,884	$0	-$11,217		-$738,258.55	-$851,633	-$0
RSVA - Wholesale Market Service Charge[9]	1580	-$94,532	$0	-$140,105		-$4,346,196.35	-$30,093,038	-$85,385
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0		$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	-$12,826	$0	-$15,316		-$586,001.52	$48,303	$85,385
RSVA - Retail Transmission Network Charge	1584	$201,091	$0	$256,749		$9,204,065.53	$17,296,882	-$0
RSVA - Retail Transmission Connection Charge	1586	$390,251	$0	$518,550		$17,882,317.91	$26,023,060	-$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$122,064	$0	-$214,909		-$5,646,008.99	-$8,935,056	$0
RSVA - Global Adjustment [12]	1589	-$537,119	$0	-$384,800		-$24,283,323.22	-$16,850,741	$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$0	-$88	☐ Check to Dispose of Account	$0.00	$0	$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0	-$1,000,322	☐ Check to Dispose of Account	$0.00	$24,290,768	$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$0	$106,951	☐ Check to Dispose of Account	$0.00	$203,308	$1
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	$0	-$711,779	☐ Check to Dispose of Account	$0.00	-$7,060,210	$2
Not to be disposed of until a year after rate rider has expired and that balance								
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,892	$0	-$1,585,581		-$8,182,702	$4,798,757	$91
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$350,227	$0	-$1,200,781		$16,100,621.45	$21,649,498	$90
RSVA - Global Adjustment 12	**1589**	-$537,119	$0	-$384,800	☐ Check to Dispose of Account	-$24,283,323.22	-$16,850,741	$0

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2016, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

2020 Deferrl/Variance Account Workform

2012

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0					$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$0					$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508					$0					$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508		$61,499,000			$61,499,000					$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508					$0					$0
Other Regulatory Assets - Sub-Account - EIP	1508					$0					$0
Other Regulatory Assets - Sub-Account - Derecognition	1508					$0					$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508					$0					$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508					$0					$0
Other Regulatory Assets - Sub-Account - OCCP	1508					$0					$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508					$0					$0
Retail Cost Variance Account - Retail	1518					$0					$0
Misc. Deferred Debits	1525					$0					$0
Retail Cost Variance Account - STR	1548					$0					$0
Board-Approved CDM Variance Account	1567					$0					$0
Extra-Ordinary Event Costs	1572					$0					$0
Deferred Rate Impact Amounts	1574					$0					$0
RSVA - One-time	1582					$0					$0
Other Deferred Credits	2425					$0					$0
Group 2 Sub-Total			$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				-$2,314,616	-$2,314,616				-$83,852	-$83,852
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				-$1,100,000	-$1,100,000				-$34,148	-$34,148
LRAM Variance Account[11]	**1568**					$0					$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000
Renewable Generation Connection Capital Deferral Account[8]	1531					$0					$0
Renewable Generation Connection OM&A Deferral Account[8]	1532					$0					$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0					$0
Smart Grid Capital Deferral Account	1534					$0					$0
Smart Grid OM&A Deferral Account	1535					$0					$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555				$59,226,643	$59,226,643					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555				-$27,078,565	-$27,078,565				$350,269	$350,269
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555				$0	$0					$0
Smart Meter OM&A Variance[4]	1556				$22,925,549	$22,925,549					$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576										
Excess Expansion Deposits (a)	2320										
Gain on sale-50/60 Eglinton Avenue (b)	2320										
Account receivable credits (c)	2208										

2013

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$34,148	-$16,169			-$50,317
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits (a)	2320										
Gain on sale-50/60 Eglinton Avenue (b)	2320										
Account receivable credits (c)	2208										

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

**This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting**

2020 Deferrl/Variance Account Workform

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0			$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0			$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142			-$112,142	$0	-$738			-$738
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$35,366,384	$48,438,858	$0	$0	$83,805,241	-$168,189	-$50,928	$0	$0	-$219,117
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428				$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320										
Gain on sale-50/60 Eglinton Avenue [(b)]	2320										
Account receivable credits [(c)]	2208										

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	-$155,757			-$155,757	$0	$0			$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	-$12,913,378			-$12,913,378	$0	-$41,430			-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$112,142	-$100,000			-$212,142	-$738	-$1,780			-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0	$339,784			$339,784	$0	$0			$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0	-$5,844,028			-$5,844,028	$0	-$66,137			-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$1,840,000			$1,840,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
LRAM Variance Account[11]	**1568**	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$83,805,241	-$16,542,164	$0	$0	$67,263,077	-$219,117	$52,357	$0	$0	-$166,760
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428			-$1,558,360	$28,948,068					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320										
Gain on sale-50/60 Eglinton Avenue [(b)]	2320										
Account receivable credits [(c)]	2208										

**For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g
figure and credit balance are to have a negative figure) as per the related OEB decision.**

Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

**This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting**

2020 Deferrl/Variance Account Workform

Account Descriptions	Account Number	2016 Opening Principal Amounts as of Jan-1-16	2016 Transactions(1) Debit / (Credit) during 2016	2016 OEB-Approved Disposition during 2016	2016 Principal Adjustments(2) during 2016	2016 Closing Principal Balance as of Dec-31-16	2016 Opening Interest Amounts as of Jan-1-16	2016 Interest Jan-1 to Dec-31-16	2016 OEB-Approved Disposition during 2016	2016 Interest Adjustments(2) during 2016	2016 Closing Interest Amounts as of Dec-31-16	2017 Opening Principal Amounts as of Jan-1-17	2017 Transactions(1) Debit / (Credit) during 2017	2017 OEB-Approved Disposition during 2017	2017 Principal Adjustments(2) during 2017	2017 Closing Principal Balance as of Dec-31-17	2017 Opening Interest Amounts as of Jan-1-17	2017 Interest Jan-1 to Dec-31-17	2017 OEB-Approved Disposition during 2017	2017 Interest Adjustments(2) during 2017	2017 Closing Interest Amounts as of Dec-31-17
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141			-$627,897	$0	-$1,154			-$1,154	-$627,897	-$698,387			-$1,326,285	-$1,154	-$3,252			-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093			-$11,623,285	-$41,430	-$169,801			-$211,231	-$11,623,285	-$3,870,968			-$15,494,253	-$211,231	-$192,636			-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016			-$312,158	-$2,518	-$2,815			-$5,333	-$312,158	-$100,000			-$412,158	-$5,333	-$4,396			-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589			$1,993,373	$0	$7,871			$7,871	$1,993,373	$2,024,793			$4,018,166	$7,871	$37,270			$45,142
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588			$8,642,560	-$66,137	-$11,273			-$77,409	$8,642,560	$18,394,134			$27,036,693	-$77,409	$212,645			$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000			$2,971,000	$0	$0			$0	$2,971,000	$1,300,000			$4,271,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502	$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2	$0				$0	$2				$2
LRAM Variance Account[11]	**1568**	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568		$67,263,077	-$4,504,470	$37,999	$1,278,369	$63,998,978	-$166,760	-$128,351	-$134,285	$0	-$160,827	$63,998,978	$37,478,243	$4,810,834	$0	$96,666,387	-$160,827	-$2,680	$139,236	$0	-$302,743
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	-$1,026,599			-$1,026,599	$0				$0	-$1,026,599	-$1,400,410			-$2,427,009	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709			$19,014,359						$19,014,359	-$6,583,043			$12,431,316					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0						$0				$0					
Excess Expansion Deposits [(a)]	2320												-$5,081,563			-$5,081,563	$0	-$204,580			-$204,580
Gain on sale-50/60 Eglinton Avenue [(b)]	2320												-$8,043,300			-$8,043,300	$0	-$52,279			-$52,279
Account receivable credits [(c)]	2208															$0	$0				$0

**For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g
figure and credit balance are to have a negative figure) as per the related OEB decision.**

Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting

2020 Deferrl/Variance Account Workform

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	Forecast 2019 Forecast Principal Amount - 2019	Forecast Interest Amount - 2019	Closing Principal Balance - Including Forecast 2019	Closing Interest Balance - Including Forecast 2019	2019 Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0							$0	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0							$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508	$0				$0	$0				$0							$0	$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$85,260,576	-$37,157,000			$48,103,576	$0				$0							$48,103,576	$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$22,747,626	-$30,124,132			-$52,871,758	-$276,927	-$630,950			-$907,877							-$52,871,758	-$907,877
Other Regulatory Assets - Sub-Account - EIP	1508	-$1,326,285	-$918,437			-$2,244,722	-$4,406	-$30,653			-$35,059							-$2,244,722	-$35,059
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$15,494,253	-$5,487,866			-$20,982,120	-$403,867	-$383,862			-$787,730							-$20,982,120	-$787,730
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$412,158	-$100,000			-$512,158	-$9,729	-$8,376			-$18,105							-$512,158	-$18,105
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$4,018,166	$3,332,692			$7,350,858	$45,142	$105,434			$150,576							$7,350,858	$150,576
Other Regulatory Assets - Sub-Account - OCCP	1508	$27,036,693	-$79,824,824			-$52,788,130	$135,235	-$634,606			-$499,371							-$52,788,130	-$499,371
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$4,271,000	$1,182,000			$5,453,000	$0	$0			$0							$5,453,000	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0							$0	$0
Misc. Deferred Debits	1525	$0				$0	$0				$0							$0	$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0							$0	$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0							$0	$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0							$0	$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0							$0	$0
RSVA - One-time	1582	$0				$0	$0				$0							$0	$0
Other Deferred Credits	2425	$0				$0	$0				$0							$0	$0
Group 2 Sub-Total		$80,606,113	-$149,097,567	$0	$0	-$68,491,454	-$514,552	-$1,583,015	$0	$0	-$2,097,567	$0	$0	$0	$0	$0	$0	-$68,491,454	-$2,097,567
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0							$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2							$0	$2
LRAM Variance Account[11]	**1568**	$16,060,274	$18,290,141	$6,447,545		$27,902,870	$211,807	$410,304	$121,812		$500,299					$12,048,215	$295,181	$15,854,655	$205,118
Total including Account 1568		$96,666,387	-$130,807,426	$6,447,545	$0	-$40,588,584	-$302,743	-$1,172,710	$121,812	$0	-$1,597,265	$0	$0	$0	$0	$12,048,215	$295,181	-$52,636,799	-$1,892,446
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0							$0	$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0							$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533	-$2,427,009	-$1,873,867			-$4,300,876	$0				$0							-$4,300,876	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0							$0	$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0							$0	$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0							$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0							$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0							$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$7,316,327	-$4,029,308			$3,287,019	$219,457	$98,856			$318,313							$3,287,019	$318,313
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0							$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0							$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$12,431,316	-$6,740,860			$5,690,456	$0				$0							$5,690,456	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0							$0	$0
Excess Expansion Deposits [(a)]	2320	-$5,081,563	-$2,412,582			-$7,494,145	-$204,580	-$145,328			-$349,908							-$7,494,145	-$349,908
Gain on sale-50/60 Eglinton Avenue [(b)]	2320	-$8,043,300	-$326,378			-$8,369,678	-$52,279	-$153,119			-$205,399							-$8,369,678	-$205,399
Account receivable credits [(c)]	2208	$0	-$3,290,798			-$3,290,798	$0	-$57,178			-$57,178							-$3,290,798	-$57,178

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Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

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data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
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from the vintage year. For any new accounts that have never been disposed, start inputting**

2020 Deferrl/Variance Account Workform

Account Descriptions	Account Number	Projected Interest on Dec-31-18 Balances: Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest	Total Claim		2.1.7 RRR: As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 2 Accounts								
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	Check to Dispose of Account	$48,103,576.00	$48,103,576	-$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$1,188,293		-$2,096,170	Check to Dispose of Account	-$54,967,928.46	-$53,779,636	-$0
Other Regulatory Assets - Sub-Account - EIP	1508	-$50,450		-$85,509	Check to Dispose of Account	-$2,330,230.90	-$2,279,781	-$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$471,573		-$1,259,303		-$22,241,422.37	-$21,769,849	-$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$850		-$17,255	Check to Dispose of Account	-$529,413.03	-$530,264	-$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$165,211		$315,786	Check to Dispose of Account	$7,666,644.43	$7,501,434	$1
Other Regulatory Assets - Sub-Account - OCCP	1508	-$1,186,413		-$1,685,784	Check to Dispose of Account Check to Dispose of Account	-$54,473,914.68	-$53,287,501	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0		$5,453,000.00	$5,453,000	$0
Retail Cost Variance Account - Retail	1518			$0	Check to Dispose of Account Check to Dispose of Account	$0.00		$0
Misc. Deferred Debits	1525			$0	Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0		$0.00		$0
RSVA - One-time	1582			$0		$0.00		$0
Other Deferred Credits	2425			$0	Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$2,730,668	$0	-$4,828,235		-$73,319,689.01	-$70,589,021	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0.00		-$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$2		$2.17		-$2
LRAM Variance Account[11]	**1568**			$205,118			$28,403,169	-$0
Total including Account 1568		-$2,730,668	$0	-$4,623,114		-$73,319,687	-$42,185,852	-$2
Renewable Generation Connection Capital Deferral Account[8]	1531			$0		$0.00		$0
Renewable Generation Connection OM&A Deferral Account[8]	1532			$0		$0.00		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0		-$4,300,876.21	-$4,300,876	$0
Smart Grid Capital Deferral Account	1534			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555			$318,313	Check to Dispose of Account	$3,605,332.64	$3,605,333	$0
Smart Meter OM&A Variance[4]	1556			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0	Check to Dispose of Account	$5,690,456.49	$5,690,456	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$0	Check to Dispose of Account	$0.00		$0
Excess Expansion Deposits [(a)]	2320	-$177,431		-$527,339	Check to Dispose of Account	-$8,021,484.00	-$7,844,053	$0
Gain on sale-50/60 Eglinton Avenue [(b)]	2320	-$188,109		-$393,507	Check to Dispose of Account	-$8,763,185.34	-$8,575,077	$0
Account receivable credits [(c)]	2208	-$59,893		-$117,070	Check to Dispose of Account	-$3,407,868.19	-$3,290,798	$57,178
					Check to Dispose of Account			

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Notes:

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(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

2020 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2017 Balance (Principal + Interest)	Explanation
3	RSVA - Wholesale Market Service Charge9	1580	$ (85,384.86)	The 2017 approved disposition for CBR class B interest of $85,385 was recorded as part of RSVA - WMS Charge (primary account) for the RRR 2.1.7 Trial Balance. For the purposes of this continuity, the interest component has been reported in the Sub-account CBR class B line. The amount corresponds to the interest approved in EB-2016-0254. See offsetting amount below in the Sub-account CBR Class B.
3.2	Variance WMS – Sub-account CBR Class B9	1580	$ 85,385.39	See above.

Billing Determinants

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.
Used 2020 Load Forecast

			A		B		C		D=A-C		E			F =B-C-E (deduct E if applicable)
Rate Class **(Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)**	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kVA**	**Metered kWh for Non-RPP Customers [5] (excluding WMP)**	**Metered kVA for Non-RPP Customers[5] (excluding WMP)**	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kVA for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kVA less WMP consumption (if applicable)**	**Total Metered 2018 kWh for Class A Customers that were Class A for the entire period the GA balance accumulated**	**Total Metered 2018 kWh for Customers that Transitioned Between Class A and B during the period the GA balance accumulated**		**Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	615,118	4,531,218,421	-	120,867,876		-	-	4,531,218,421	-	-	-	**4,531,218,421**	120,867,876
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CI	kWh	85,852	297,763,685	-	1,256,022		-	-	297,763,685	-	-	-	**297,763,685**	1,256,022
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	71,599	2,299,006,608	-	340,748,367		-	-	2,299,006,608	-	-	-	**2,299,006,608**	340,748,367
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	10,417	9,659,470,299	24,899,004	6,675,659,664	17,765,688	51,161,050	107,338	9,608,309,249	24,791,665	172,242,450	171,190,992	**9,264,875,806**	6,332,226,222
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICAT	kVA	430	4,595,446,119	10,406,674	4,411,896,455	10,021,029	430,714	14,192	4,595,015,405	10,392,482	2,849,579,357	801,154,480	**944,281,567**	761,162,617
LARGE USE SERVICE CLASSIFICATION	kVA	38	2,164,924,150	4,600,360	1,908,284,149	4,126,573	275,445,723	503,078	1,889,478,427	4,097,281	1,678,111,033	29,403,915	**181,963,479**	200,769,201
STANDBY POWER SERVICE CLASSIFICATION	kVA		-	-			-	-	-	-	-	-	**-**	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	825	40,588,612	-	118,578		-	-	40,588,612	-	-	-	**40,588,612**	118,578
STREET LIGHTING SERVICE CLASSIFICATION	kVA	1	116,219,746	326,300	116,219,746	326,300	-	-	116,219,746	326,300	-	-	**116,219,746**	116,219,746
Total		**784,280**	**23,704,637,639**	**40,232,337**	**13,575,050,857**	**32,239,590**	**327,037,487**	**624,609**	**23,377,600,153**	**39,607,728**	**4,699,932,841**	**1,001,749,388**	**17,675,917,924**	**7,873,368,628**

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

[3] Input the allocation as determined in the LRAMVA model. The associated rate riders will be calculated in the EDDVAR model.

[5] If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are

Allocation of Balances

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	STANDBY POWER SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	330,703	kWh	63,215	4,154	32,073	134,759	64,111	30,203	0	566	1,621
Smart Metering Entity Charge Variance Account	1551	(738,259)	# of Customers	(587,800)	(82,039)	(68,419)	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(4,346,196)	kWh	(842,412)	(55,358)	(427,415)	(1,786,308)	(854,272)	(351,278)	0	(7,546)	(21,607)
RSVA - Retail Transmission Network Charge	1584	9,204,066	kWh	1,759,387	115,616	892,661	3,750,591	1,784,325	840,599	0	15,760	45,126
RSVA - Retail Transmission Connection Charge	1586	17,882,318	kWh	3,418,263	224,627	1,734,326	7,286,917	3,466,715	1,633,177	0	30,619	87,674
RSVA - Power (excluding Global Adjustment)	1588	(5,646,009)	kWh	(1,094,351)	(71,914)	(555,241)	(2,320,538)	(1,109,759)	(456,335)	0	(9,803)	(28,069)
RSVA - Global Adjustment	1589	(22,861,167)	Non-RPP kWh	(350,953)	(3,647)	(989,399)	(18,386,295)	(2,210,117)	(582,955)	0	(344)	(337,456)
Total of Group 1 Accounts (excluding 1589)		**16,686,623**		**2,716,302**	**135,086**	**1,607,985**	**7,065,421**	**3,351,120**	**1,696,366**	**0**	**29,597**	**84,746**
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(570,202)**	**kWh**	**(146,171)**	**(9,605)**	**(74,163)**	**(298,873)**	**(30,461)**	**(5,870)**	**0**	**(1,309)**	**(3,749)**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**26,678,828**		**4,653,065**	**262,358**	**2,590,641**	**11,172,267**	**5,315,152**	**2,503,979**	**0**	**46,945**	**134,421**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(9,992,205)**		**(1,936,763)**	**(127,272)**	**(982,656)**	**(4,106,846)**	**(1,964,031)**	**(807,613)**	**0**	**(17,349)**	**(49,675)**
Balance of Account 1589 Allocated to Non-WMPs		**(22,861,167)**		**(350,953)**	**(3,647)**	**(989,399)**	**(18,386,295)**	**(2,210,117)**	**(582,955)**	**0**	**(344)**	**(337,456)**

Class A Consumption Data

1	**Please enter the Year the Account 1589 GA Balance was Last Disposed.**	2017	**(e.g. If in the 2018 EDR process, you received approval to dispose the GA variance account balance as at December 31, 2016, enter 2016.)**
2a	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from year after the balance was last disposed to 2017)?**	Yes	**(e.g. If you received approval to dispose the GA account balance as at December 31, 2016, the period the GA accumulated would be 2017.)**
2b	**Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from year after the balance was last disposed to 2017).**	Yes	**(e.g. If the CBR Class B balance was last disposed as at December 31, 2016, the period the CBR Class B variance accumulated would be 2017.)**
3a	**Enter the number of transition customers you had during the period the Account 1589 GA balance accumulated.**	127	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2018 January to June	2018 July to December
Customer 1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	15,237,254	10,750,334
		kVA	37,162	31,849
		Class A/B	A	B
Customer 2	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	70,146,308	75,057,096
		kVA	198,802	199,630
		Class A/B	B	A
Customer 3	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	68,119,407	65,561,674
		kVA	199,249	193,805
		Class A/B	A	B
Customer 4	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	329,125,988	338,347,412
		kVA	698,099	733,007
		Class A/B	B	A
Customer 5	LARGE USE SERVICE CLASSIFICATION	kWh	14,205,212	15,198,704
		kVA	41,746	41,028
		Class A/B	B	A

3b	**Enter the number of customers who were Class A during the entire period since the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B).**	278

Class A Customers - Billing Determinants by Customer

Customer	Rate Class		2018
Customer A1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	172,242,450
		kVA	419,165
Customer A2	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	2,849,579,357
		kVA	6,029,167
Customer A3	LARGE USE SERVICE CLASSIFICATION	kWh	1,678,111,033
		kVA	3,329,196

GA Allocation

This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculates specific amounts for each transition customer. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year of the Account 1589 GA Balance Last Disposed	**2017**

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2018	
Total Class B Consumption for Years During Balance Accumulation (Non-RPP Consumption LESS WMP Consumption and Consumption for Class A customers who were Class A for partial and full year)	A	8,363,158,143	8,363,158,143	
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515	
Transition Customers' Portion of Total Consumption	C=B/A	**5.86%**	**7,873,368,628**	-

Allocation of Total GA Balance $

Total GA Balance	D	-$ 24,283,323
Transition Customers Portion of GA Balance	E=C*D	-$ 1,422,156
GA Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 22,861,167

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers**	**Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers in 2017**	**% of kWh**	**Customer Specific GA Allocation During the Period They Were a Class B customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 31,215	-$ 2,601
Customer 2		70,146,308	70,146,308	14.32%	-$ 203,677	-$ 16,973
Customer 3		65,561,674	65,561,674	13.39%	-$ 190,365	-$ 15,864
Customer 4		329,125,988	329,125,988	67.20%	-$ 955,652	-$ 79,638
Customer 5		14,205,212	14,205,212	2.90%	-$ 41,246	-$ 3,437
		489,789,515	**489,789,515**	**100.00%**	**-$ 1,422,156**	**-$ 118,513**

CBR B Allocation

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each transition customer. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Please enter the Year the Account 1580 CBR Class B was Last Disposed. 2017 **(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

Allocation of total Consumption (kWh) between Class B and Class A/B Transition Customers

		Total	2017	
Total Class B Consumption for Years During Balance Accumulation (Total Consumption Less WMP Consumption and Consumption for Class A who were Class A for the full year)	A	18,165,707,440	18,165,707,440	
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515	
Transition Customers' Portion of Total Consumption	C=B/A	2.70%	17,675,917,924	-

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	D	-$ 586,002
Transition Customers Portion of CBR Class B Balance	E=D*C	-$ 15,800
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 570,202

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers**	**Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation During the Period They Were a Class B Customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 347	-$ 29
Customer 2		70,146,308	70,146,308	14.32%	-$ 2,263	-$ 189
Customer 3		65,561,674	65,561,674	13.39%	-$ 2,115	-$ 176
Customer 4		329,125,988	329,125,988	67.20%	-$ 10,617	-$ 885
Customer 5		14,205,212	14,205,212	2.90%	-$ 458	-$ 38
		489,789,515	**489,789,515**	100.00%	**-$ 15,800**	**-$ 1,317**

CBR B

The purpose of this tab is to calculate the billing determinants for CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The Year the Account 1580 CBR Class B was Last Disposed. 2017 **(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

	Total Metered 2018 Consumption Minus WMP		Total Metered 2018 Consumption for Class A customers that were Class A for the entire period CBR Class B balance accumulated		Total Metered 2018 Consumption for Customers that Transitioned Between Class A and B during the period CBR Class B balance accumulated		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh
	kWh	kVA	kWh	kVA	kWh	kVA	kWh	kVA	
RESIDENTIAL SERVICE CLASSIFICATION	4,531,218,421	-	0	0	0	0	4,531,218,421	-	26%
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFIC/	297,763,685	-	0	0	0	0	297,763,685	-	2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	2,299,006,608	-	0	0	0	0	2,299,006,608	-	13%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	9,608,309,249	24,791,665	172,242,450	419,165	171,190,992	467,443	9,264,875,806	23,905,058	52%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	4,595,015,405	10,392,482	2,849,579,357	6,029,167	801,154,480	1,824,160	944,281,567	2,539,155	5%
LARGE USE SERVICE CLASSIFICATION	1,889,478,427	4,097,281	1,678,111,033	3,329,196	29,403,915	82,773	181,963,479	685,312	1%
STANDBY POWER SERVICE CLASSIFICATION	-	-	0	0	0	0	-	-	0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	40,588,612	-	0	0	0	0	40,588,612	-	0%
STREET LIGHTING SERVICE CLASSIFICATION	116,219,746	326,300	0	0	0	0	116,219,746	326,300	1%
Total	23,377,600,153	39,607,728	4,699,932,841	9,777,527	1,001,749,388	2,374,376	17,675,917,924	27,455,825	100%

GROUP 1 Rate Rider Calculations

Please indicate the Rate Rider Recovery Period (in years) | **12**

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	**Units**	**kVA / kWh / # of Customers**	**Allocated Group 1 Balance (excluding 1589)**	**Rate Rider for Deferral/Variance Accounts**	**ROUNDED Rate Rider for Deferral/Variance Accounts**	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ 2,716,302	**0.00060**	0.00060	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	$ 135,086	**0.00045**	0.00045	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ 1,607,985	**0.00070**	0.00070	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,899,004	$ 11,172,267	**0.44256**	0.44260	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,406,674	$ 5,315,152	**0.50375**	0.50370	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,600,360	$ 2,503,979	**0.53684**	0.53680	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ 29,597	**0.00073**	0.00073	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ 84,746	**0.25616**	0.25620	$/kVA
Total			**$ 23,565,113**			

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Group 1 Balance - Non-WMP**	**Rate Rider for Deferral/Variance Accounts for Non-WMP**	**ROUNDED Rate Rider for Deferral/Variance Accounts for Non-WMP**	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ -	**-**	-	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	$ -	**-**	-	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ -	**-**	-	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,791,665	-$ 4,106,846	**- 0.16339**	- 0.16340	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,392,482	-$ 1,964,031	**- 0.18640**	- 0.18640	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,097,281	-$ 807,613	**- 0.19441**	- 0.19440	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ -	**-**	-	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ -	**-**	-	$/kVA
Total			**-$ 6,878,490**			

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Sub-account 1580 CBR Class B Balance**	**Rate Rider for Sub-account 1580 CBR Class B**	**ROUNDED Rate Rider for Sub-account 1580 CBR Class B**	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	-$ 146,171	**- 0.00003**	- 0.00003	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	-$ 9,605	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	-$ 74,163	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	23,905,058	-$ 298,873	**- 0.01233**	- 0.01230	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	2,539,155	-$ 30,461	**- 0.01183**	- 0.01180	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	685,312	-$ 5,870	**- 0.00845**	- 0.00840	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	-$ 1,309	**- 0.00003**	- 0.00003	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	-$ 3,749	**- 0.01133**	- 0.01130	$/kVA
Total			**-$ 570,202**			

Rate rider calculated separately only if Class A customers exist during the period the balance accumulated

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	**Units**	**kWh**	**Allocated Global Adjustment Balance**	**Rate Rider for RSVA - Power - Global Adjustment**	**ROUNDED Rate Rider for RSVA - Power - Global Adjustment**	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	120,867,876	-$ 350,953	**- 0.00290**	- 0.00290	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	1,256,022	-$ 3,647	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	340,748,367	-$ 989,399	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	6,332,226,222	-$ 18,386,295	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kWh	761,162,617	-$ 2,210,117	**- 0.00290**	- 0.00290	$/kWh
LARGE USE SERVICE CLASSIFICATION	kWh	200,769,201	-$ 582,955	**- 0.00290**	- 0.00290	$/kWh
STANDBY POWER SERVICE CLASSIFICATION	kWh	-	$ -	**-**	-	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	118,578	-$ 344	**- 0.00290**	- 0.00290	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	116,219,746	-$ 337,456	**- 0.00290**	- 0.00290	$/kWh
Total			**-$ 22,861,167**			

Group 2 Rate Riders Development

% to split by Class

	% to split by Class	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Allocators										
	2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
	2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
	Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
	AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%

Allocation of Balances

		Account Number	Allocators (Drop Down)	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	0	0		-	-	-	-	-	-	-	-	-	-
1	Wireless pole attachments Rev	1508	2020 Revenue Offsets	- 529,413	- 260,690	- 21,069	- 108,118	- 96,907	- 18,574	- 7,859	- 12,071	- 4,124	-
2	Impact for USGAAP (Actuarial loss on OPEB)	1508	2017 Distribution Revenue	48,103,576	19,087,915	1,783,829	6,806,795	12,996,819	4,093,974	2,135,323	953,529	245,391	-
3	CRRRVA	1508	2017 Distribution Revenue	- 54,967,928	- 21,811,749	- 2,038,381	- 7,778,121	- 14,851,458	- 4,678,181	- 2,440,033	- 1,089,597	- 280,408	-
4	Monthly Billing	1508	Monthly Billing Conversion	7,666,644	6,872,968	-	793,677	-	-	-	-	-	-
5	External Driven Capital	1508	2017 Distribution Revenue	- 2,330,231	- 924,656	- 86,412	- 329,734	- 629,591	- 198,320	- 103,439	- 46,191	- 11,887	-
6	OPEB cash vs accrual	1508	2017 Distribution Revenue	5,453,000	2,163,798	202,214	771,615	1,473,314	464,091	242,059	108,092	27,817	-
7	Derecognition	1508	2017 Distribution Revenue	- 22,241,422	- 8,825,589	- 824,781	- 3,147,226	- 6,009,278	- 1,892,911	- 987,299	- 440,879	- 113,460	-
8	Deferred Gain on disposals	2320	2017 Distribution Revenue	- 8,763,185	- 3,477,308	- 324,966	- 1,240,016	- 2,367,673	- 745,813	- 388,999	- 173,708	- 44,704	-
9	Operations Consolidation Plan Sharing Variance	1508	2017 Distribution Revenue	- 54,473,915	- 21,615,720	- 2,020,061	- 7,708,217	- 14,717,983	- 4,636,137	- 2,418,103	- 1,079,805	- 277,888	-
10	Excess Expansion Deposits	2320	Distribution Revenue GS>50 kW	- 8,021,484	-	-	-	- 5,104,215	- 1,607,818	- 838,601	- 374,478	- 96,372	-
11	AR Credits	2208	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-
	Total			- 93,512,227	- 31,635,512	- 3,329,627	- 12,449,775	- 29,359,016	- 9,220,105	- 4,806,951	- 2,155,107	- 556,135	

Load / Customers / Devices / Connections Forecast

			Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	2020 Forecast Dist Billing Determinants (Jan - Dec)											
	kVA		40,232,337	NA	NA	NA	24,899,004	10,406,674	4,600,360	326,300	NA	-
	kWh		23,377,600,153	4,531,218,421	297,763,685	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	-
	Number of Customers		784,280	615,118	85,852	71,599	10,417	430	38	1	-	825
	Devices/Connections		177,454	NA	NA	NA	NA	NA	NA	165,274	12,180	-

Rate Rider Calculation

		Account Number	RR Pass-through or not	Proposed Recovery Period (years)	Amount	Allocators	Rate Rider Start Year	Rate Rider End Year	Billing Unit	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
										-	-	-	-	-	-	-	-	-
1	Wireless pole attachments Rev	1508	Not Pass-through	5.00	- 529,413	2020 Revenue Offsets	2020	2024	Cust.+ Usage [1]	- 0.01	-	- 0.00001	- 0.00080	- 0.00040	- 0.00030	- 0.00730	- 0.00002	-
2	Impact for USGAAP (Actuarial loss on OPEB)	1508	Not Pass-through	5.00	48,103,576	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	0.51	0.34	0.00059	0.10300	0.07760	0.09160	0.57640	0.00121	-
3	CRRRVA	1508	Not Pass-through	5.00	- 54,967,928	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	- 0.58	- 0.39	- 0.00068	- 0.11770	- 0.08870	- 0.10460	- 0.65870	- 0.00138	-
4	Monthly Billing	1508	Not Pass-through	5.00	7,666,644	Monthly Billing Convers	2020	2024	Cust.+ Usage [1]	0.18	-	0.00007	-	-	-	-	-	-
5	External Driven Capital	1508	Not Pass-through	5.00	- 2,330,231	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.02	- 0.00003	- 0.00500	- 0.00380	- 0.00440	- 0.02790	- 0.00006	-
6	OPEB cash vs accrual	1508	Not Pass-through	5.00	5,453,000	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	0.06	0.04	0.00007	0.01170	0.00880	0.01040	0.06530	0.00014	-
7	Derecognition	1508	Not Pass-through	5.00	- 22,241,422	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	- 0.24	- 0.16	- 0.00027	- 0.04760	- 0.03590	- 0.04230	- 0.26650	- 0.00056	-
8	Deferred Gain on disposals	2320	Not Pass-through	5.00	- 8,763,185	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	- 0.09	- 0.06	- 0.00011	- 0.01880	- 0.01410	- 0.01670	- 0.10500	- 0.00022	-
9	Operations Consolidation Plan Sharing Variance	1508	Not Pass-through	5.00	- 54,473,915	2017 Distribution Rever	2020	2024	Cust.+ Usage [1]	- 0.58	- 0.39	- 0.00067	- 0.11660	- 0.08790	- 0.10370	- 0.65280	- 0.00137	-
10	Excess Expansion Deposits	2320	Not Pass-through	5.00	- 8,021,484	Distribution Revenue G:	2020	2024	Cust.+ Usage [1]	-	-	-	- 0.04040	- 0.03050	- 0.03600	- 0.22640	- 0.00047	-
11	AR Credits	2208	Not Pass-through	5.00	- 3,407,868	AR Credits	2020	2024	Cust.+ Usage [1]	- 0.08	-	- 0.00004	- 0.00040	-	-	-	-	-

[1] "Customers" means Residential, GS < 50 kW and GS 50 to 999 kW rates recovery are based on $/cust/30 days
[1] "Cust.+Usage" means Residential and CSMUR rates recovery are based on $/cust/30 days and all other Rate classes recovery are based on $/kWh or $/kVA or $/Device or $/Connection

2020 Deferrl/Variance Account Workform

		2012										2013									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts																					
LV Variance Account	1550					$0					$0	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551															$0	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580					$0					$0	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580																				
Variance WMS – Sub-account CBR Class B[9]	1580																				
RSVA - Retail Transmission Network Charge	1584					$0					$0	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586					$0					$0	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588					$0					$0	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595					$0					$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595																				
Not to be disposed of until a year after rate rider has expired and that balance has been audited																					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB

2020 Deferrl/Variance A

Group 1 Accounts

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$109,729			$109,729	$0	-$261,355			-$261,355
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
LV Variance Account	1550	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580		$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580		$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

2020 Deferrl/Variance A

Account Descriptions	Account Number	2016 Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 1 Accounts											
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$54,487	$966			-$53,521
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712

Account Descriptions	Account Number	2017 Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 1 Accounts											
LV Variance Account	1550	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$81,084,945	$56,920,194	$94,368,616		$43,636,523	$4,942,712	$274,057	$4,812,604		$404,166
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0				$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$11,436,118	$34,580,526	$23,676,474	$0	-$532,067	$2,108,037	-$600,683	$2,182,727	-$993,537	-$1,668,911
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$92,521,064	-$22,339,668	-$70,692,141	$0	-$44,168,591	-$2,834,676	-$874,740	-$2,629,877	-$993,537	-$2,073,076
RSVA - Global Adjustment 12	**1589**	$81,084,945	$56,920,194	$94,368,616	$0	$43,636,523	$4,942,712	$274,057	$4,812,604	$0	$404,166

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

2020 Deferrl/Variance A

		2018										2019			
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 1 Accounts															
LV Variance Account	1550	$706,353	$320,000	$312,025	$0	$714,328	$8,068	$10,579	$5,861	$0	$12,787	$394,328	$9,276	$320,000	$3,511
Smart Metering Entity Charge Variance Account	1551	-$492,958	-$727,042	-$379,776	$0	-$840,224	$3,001	-$1,169	$13,241	$0	-$11,409	-$113,182	-$19,076	-$727,042	$7,667
RSVA - Wholesale Market Service Charge[9]	1580	-$51,235,576	-$4,206,092	-$26,035,862	$0	-$29,405,806	-$602,984	-$497,277	-$498,414	$0	-$601,847	-$25,199,715	-$556,274	-$4,206,092	-$45,573
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$2,059,564	-$570,685	$1,535,334	$0	-$46,455	-$50,215	$6,908	-$52,680	$0	$9,373	$524,231	$11,862	-$570,686	-$2,489
RSVA - Retail Transmission Network Charge	1584	-$8,318,223	$8,947,315	-$16,414,402	$0	$17,043,495	-$153,109	$200,783	-$205,715	$0	$253,388	$8,096,178	$197,730	$8,947,316	$55,658
RSVA - Retail Transmission Connection Charge	1586	-$21,616,765	$17,363,768	-$29,949,890	$0	$25,696,892	-$397,823	$277,670	-$446,320	$0	$326,167	$8,333,125	$197,868	$17,363,768	$128,299
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,241,858	-$5,431,100	-$4,904,742		-$8,768,216	-$112,749	-$152,662	-$98,572	$0	-$166,840	-$3,337,116	-$73,995	-$5,431,100	-$92,845
RSVA - Global Adjustment [12]	1589	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,587	$493,758	$6,554,025	$341,438	-$23,898,523	$152,320
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	$0	$0	$0	-$0	$0	$0	$0	-$0	$0	$0	$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$0	$0	$0	$0	-$0	-$0	$0	$0	$0	-$0	$0	$0	-$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	-$0	$0	$0	$0	-$0	$0	$0	$0	$0	$0	$0	$0	-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	-$0	$0	$0	$0	-$0	-$88	$0	$0	$0	-$88	$0	$0	-$0	-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$40,179,133	-$14,888,043	$0	$0	$25,291,090	-$909,242	-$91,080	$0	$0	-$1,000,322	$0	$0	$25,291,090	-$1,000,322
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$2,791,740	-$2,695,385	$0	$0	$96,355	$142,065	-$35,114	$0	$0	$106,951	$0	$0	$96,355	$106,951
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	-$6,348,433	$0	$0	-$6,348,433	$0	-$711,779	$0	$0	-$711,779	$0	$0	-$6,348,433	-$711,779
Not to be disposed of until a year after rate rider has expired and that balanc															
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$532,067	-$32,134,222	-$89,120,985	-$50,366,169	$6,088,526	-$1,668,911	-$718,751	-$1,225,388	-$127,587	-$1,289,860	-$4,748,127	$108,829	$10,836,653	-$1,398,689
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$44,168,591	-$8,235,698	-$75,837,313	$0	$23,433,025	-$2,073,076	-$993,140	-$1,282,599	$0	-$1,783,618	-$11,302,151	-$232,609	$34,735,176	-$1,551,009
RSVA - Global Adjustment 12	**1589**	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,587	$493,758	$6,554,025	$341,438	-$23,898,523	$152,320

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

2020 Deferrl/Variance A

If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2017), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 6 will be generated and applicants must complete the information pertaining to Class A customers.

		Projected Interest on Dec-31-18 Balances					2.1.7 RRR	
Account Descriptions	Account Number	Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest		Total Claim	As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 1 Accounts								
LV Variance Account	1550	$7,192	$0	$10,703		$330,703.40	$727,114	-$1
Smart Metering Entity Charge Variance Account	1551	-$18,884	$0	-$11,217		-$738,258.55	-$851,633	-$0
RSVA - Wholesale Market Service Charge[9]	1580	-$94,532	$0	-$140,105		-$4,346,196.35	-$30,093,038	-$85,385
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0		$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	-$12,826	$0	-$15,316		-$586,001.52	$48,303	$85,385
RSVA - Retail Transmission Network Charge	1584	$201,091	$0	$256,749		$9,204,065.53	$17,296,882	-$0
RSVA - Retail Transmission Connection Charge	1586	$390,251	$0	$518,550		$17,882,317.91	$26,023,060	-$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$122,064	$0	-$214,909		-$5,646,008.99	-$8,935,056	$0
RSVA - Global Adjustment [12]	1589	-$537,119	$0	-$384,800		-$24,283,323.22	-$16,850,741	$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	$0	-$0		$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$0	-$88	☐ Check to Dispose of Account	$0.00	$0	$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	☐ Check to Dispose of Account	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0	-$1,000,322	☐ Check to Dispose of Account	$0.00	$24,290,768	$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$0	$106,951	☐ Check to Dispose of Account	$0.00	$203,308	$1
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	$0	-$711,779	☐ Check to Dispose of Account	$0.00	-$7,060,210	$2
Not to be disposed of until a year after rate rider has expired and that balance								
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,892	$0	-$1,585,581		-$8,182,702	$4,798,757	$91
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$350,227	$0	-$1,200,781		$16,100,621.45	$21,649,498	$90
RSVA - Global Adjustment 12	**1589**	-$537,119	$0	-$384,800	☐ Check to Dispose of Account	-$24,283,323.22	-$16,850,741	$0

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2016, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2011, if a utility has an Account 1595 with a vintage year prior to 2011, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

2020 Deferrl/Variance Account Workform

Account Descriptions	Account Number	2012										2013									
		Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variar	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508		$61,499,000			$61,499,000					$0	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518					$0					$0	$0				$0	$0				$0
Misc. Deferred Debits	1525					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548					$0					$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0					$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0				$0
RSVA - One-time	1582					$0					$0	$0				$0	$0				$0
Other Deferred Credits	2425					$0					$0	$0				$0	$0				$0
Group 2 Sub-Total			$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0	$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				-$2,314,616	-$2,314,616				-$83,852	-$83,852	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				-$1,100,000	-$1,100,000				-$34,148	-$34,148	-$1,100,000				-$1,100,000	-$34,148	-$16,169			-$50,317
LRAM Variance Account[11]	**1568**					$0					$0	$0				$0	$0				$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000	$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral Account[8]	1531					$0					$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532					$0					$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0					$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0					$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535					$0					$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555				$59,226,643	$59,226,643					$0	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555				-$27,078,565	-$27,078,565				$350,269	$350,269	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555				$0	$0					$0	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556				$22,925,549	$22,925,549					$0	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557																				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0						$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576											$0				$0					
Excess Expansion Deposits [(a)]	2320																				
Gain on sale-50/60 Eglinton Avenue [(b)]	2320																				
Account receivable credits [(c)]	2208																				

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.
Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

**This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting**

2020 Deferrl/Variance Account Workform

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0			$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0			$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142			-$112,142	$0	-$738			-$738
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0
Total including Account 1568		$35,366,384	$48,438,858	$0	$0	$83,805,241	-$168,189	-$50,928	$0	$0	-$219,117
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428				$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320										
Gain on sale-50/60 Eglinton Avenue [(b)]	2320										
Account receivable credits [(c)]	2208										

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	-$155,757			-$155,757	$0	$0			$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	-$12,913,378			-$12,913,378	$0	-$41,430			-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$112,142	-$100,000			-$212,142	-$738	-$1,780			-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0	$339,784			$339,784	$0	$0			$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0	-$5,844,028			-$5,844,028	$0	-$66,137			-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$1,840,000			$1,840,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
LRAM Variance Account[11]	**1568**	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$83,805,241	-$16,542,164	$0	$0	$67,263,077	-$219,117	$52,357	$0	$0	-$166,760
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428			-$1,558,360	$28,948,068					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320										
Gain on sale-50/60 Eglinton Avenue [(b)]	2320										
Account receivable credits [(c)]	2208										

**For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (
positive figure and credit balance are to have a negative figure) as per the related OEB decision.**

Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting

2020 Deferrl/Variance Account Workform

2016

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141			-$627,897	$0	-$1,154			-$1,154
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093			-$11,623,285	-$41,430	-$169,801			-$211,231
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016			-$312,158	-$2,518	-$2,815			-$5,333
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589			$1,993,373	$0	$7,871			$7,871
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588			$8,642,560	-$66,137	-$11,273			-$77,409
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000			$2,971,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2
LRAM Variance Account[11]	**1568**	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673
Total including Account 1568		$67,263,077	-$4,504,470	$37,999	$1,278,369	$63,998,978	-$166,760	-$128,351	-$134,285	$0	-$160,827
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0	-$1,026,599			-$1,026,599	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709			$19,014,359					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320										
Gain on sale-50/60 Eglinton Avenue [(b)]	2320										
Account receivable credits [(c)]	2208										

2017

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	1508	-$627,897	-$698,387			-$1,326,285	-$1,154	-$3,252			-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$11,623,285	-$3,870,968			-$15,494,253	-$211,231	-$192,636			-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$312,158	-$100,000			-$412,158	-$5,333	-$4,396			-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$1,993,373	$2,024,793			$4,018,166	$7,871	$37,270			$45,142
Other Regulatory Assets - Sub-Account - OCCP	1508	$8,642,560	$18,394,134			$27,036,693	-$77,409	$212,645			$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$2,971,000	$1,300,000			$4,271,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2
LRAM Variance Account[11]	**1568**	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568		$63,998,978	$37,478,243	$4,810,834	$0	$96,666,387	-$160,827	-$2,680	$139,236	$0	-$302,743
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	-$1,026,599	-$1,400,410			-$2,427,009	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$19,014,359	-$6,583,043			$12,431,316					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					
Excess Expansion Deposits [(a)]	2320		-$5,081,563			-$5,081,563	$0	-$204,580			-$204,580
Gain on sale-50/60 Eglinton Avenue [(b)]	2320		-$8,043,300			-$8,043,300	$0	-$52,279			-$52,279
Account receivable credits [(c)]	2208					$0	$0				$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (
positive figure and credit balance are to have a negative figure) as per the related OEB decision.
Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting

2020 Deferrl/Variance Account Workform

		2018										Forecast 2019				2019			
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	Forecast Principal Amount - 2019	Forecast Interest Amount - 2019	Closing Principal Balance - Including Forecast 2019	Closing Interest Balance - Including Forecast 2019	Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$85,260,576	-$37,157,000			$48,103,576	$0				$0			$48,103,576	$0			$48,103,576	$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$22,747,626	-$30,124,132			-$52,871,758	-$276,927	-$630,950			-$907,877	-$22,772,218	-$228,813	-$75,643,977	-$1,136,691			-$75,643,977	-$1,136,691
Other Regulatory Assets - Sub-Account - EIP	1508	-$1,326,285	-$918,437			-$2,244,722	-$4,406	-$30,653			-$35,059	-$833,163	-$6,811	-$3,077,885	-$41,870			-$3,077,885	-$41,870
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$15,494,253	-$5,487,866			-$20,982,120	-$403,867	-$383,862			-$787,730	-$12,135,667	-$121,938	-$33,117,786	-$909,668			-$33,117,786	-$909,668
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$412,158	-$100,000			-$512,158	-$9,729	-$8,376			-$18,105	-$100,000	-$11,412	-$612,158	-$29,517			-$612,158	-$29,517
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$4,018,166	$3,332,692			$7,350,858	$45,142	$105,434			$150,576	$4,143,047	$41,629	$11,493,905	$192,205			$11,493,905	$192,205
Other Regulatory Assets - Sub-Account - OCCP	1508	$27,036,693	-$79,824,824			-$52,788,130	$135,235	-$634,606			-$499,371	-$19,060,013	$0	-$71,848,144	-$499,371			-$71,848,144	-$499,371
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$4,271,000	$1,182,000			$5,453,000	$0	$0			$0	$2,627,000	$0	$8,080,000	$0			$8,080,000	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0			$0	$0			$0	$0
Misc. Deferred Debits	1525	$0				$0	$0				$0			$0	$0			$0	$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0			$0	$0			$0	$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0			$0	$0			$0	$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0			$0	$0			$0	$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0			$0	$0			$0	$0
RSVA - One-time	1582	$0				$0	$0				$0			$0	$0			$0	$0
Other Deferred Credits	2425	$0				$0	$0				$0			$0	$0			$0	$0
Group 2 Sub-Total		$80,606,113	-$149,097,567	$0	$0	-$68,491,454	-$514,552	-$1,583,015	$0	$0	-$2,097,567	-$48,131,014	-$327,346	-$116,622,468	-$2,424,913	$0	$0	-$116,622,468	-$2,424,913
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0			$0	$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2			$0	$2			$0	$2
LRAM Variance Account[11]	**1568**	$16,060,274	$18,290,141	$6,447,545		$27,902,870	$211,807	$410,304	$121,812		$500,299			$27,902,870	$500,299	$12,048,215	$295,181	$15,854,655	$205,118
Total including Account 1568		$96,666,387	-$130,807,426	$6,447,545	$0	-$40,588,584	-$302,743	-$1,172,710	$121,812	$0	-$1,597,265	-$48,131,014	-$327,346	-$88,719,599	-$1,924,611	$12,048,215	$295,181	-$100,767,814	-$2,219,792
Renewable Generation Connection Capital Deferral Account[8]	1531	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection OM&A Deferral Account[8]	1532	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533	-$2,427,009	-$1,873,867			-$4,300,876	$0				$0	-$2,236,159		-$6,537,035	$0			-$6,537,035	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555	$7,316,327	-$4,029,308			$3,287,019	$219,457	$98,856			$318,313	-$4,674,263	-$318,313	-$1,387,244	$0			-$1,387,244	$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0			$0	$0			$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0			$0	$0			$0	$0
																		$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$12,431,316	-$6,740,860			$5,690,456	$0				$0	-$7,248,817		-$1,558,360	$0			-$1,558,360	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0			$0	$0			$0	$0
Excess Expansion Deposits [(a)]	2320	-$5,081,563	-$2,412,582			-$7,494,145	-$204,580	-$145,328			-$349,908			-$7,494,145	-$349,908			-$7,494,145	-$349,908
Gain on sale-50/60 Eglinton Avenue [(b)]	2320	-$8,043,300	-$326,378			-$8,369,678	-$52,279	-$153,119			-$205,399	- 3,017,639.00		-$11,387,317	-$205,399			-$11,387,317	-$205,399
Account receivable credits [(c)]	2208	$0	-$3,290,798			-$3,290,798	$0	-$57,178			-$57,178			-$3,290,798	-$57,178			-$3,290,798	-$57,178
														$0	$0				

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (
positive figure and credit balance are to have a negative figure) as per the related OEB decision.
Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

This continuity schedule must be completed for each account and sub-account that the utili
data from the year in which the GL balance was last disposed. For example, if in the 2017 ra
the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data
relevant balances approved for disposition was first transferred into Account 1595 (2014). T
from the vintage year. For any new accounts that have never been disposed, start inputting

2020 Deferrl/Variance Account Workform

Account Descriptions	Account Number	Projected Interest on Dec-31-18 Balances: Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)	Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)	Total Interest	Total Claim		2.1.7 RRR: As of Dec 31-18	Variance RRR vs. 2018 Balance (Principal + Interest)
Group 2 Accounts								
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Varian	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	Check to Dispose of Account	$48,103,576.00	$48,103,576	-$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$1,188,293		-$2,324,983	Check to Dispose of Account	-$77,968,960.17	-$53,779,636	-$0
Other Regulatory Assets - Sub-Account - EIP	1508	-$50,450		-$92,320	Check to Dispose of Account	-$3,170,205.06	-$2,279,781	-$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$471,573		-$1,381,241		-$34,499,027.38	-$21,769,849	-$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$850		-$28,667	Check to Dispose of Account	-$640,825.32	-$530,264	-$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$165,211		$357,415	Check to Dispose of Account	$11,851,320.65	$7,501,434	$1
Other Regulatory Assets - Sub-Account - OCCP	1508	-$1,186,413		-$1,685,784	Check to Dispose of Account Check to Dispose of Account	-$73,533,927.94	-$53,287,501	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0		$8,080,000.00	$5,453,000	$0
Retail Cost Variance Account - Retail	1518			$0	Check to Dispose of Account Check to Dispose of Account	$0.00		$0
Misc. Deferred Debits	1525			$0	Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0		$0.00		$0
RSVA - One-time	1582			$0		$0.00		$0
Other Deferred Credits	2425			$0	Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$2,730,668	$0	-$5,155,581		-$121,778,049.22	-$70,589,021	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0.00		-$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$2		$2.17		-$2
LRAM Variance Account[11]	**1568**			$205,118			$28,403,169	-$0
Total including Account 1568		-$2,730,668	$0	-$4,950,460		-$121,778,047	-$42,185,852	-$2
Renewable Generation Connection Capital Deferral Account[8]	1531			$0		$0.00		$0
Renewable Generation Connection OM&A Deferral Account[8]	1532			$0		$0.00		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0		-$6,537,035.00	-$4,300,876	$0
Smart Grid Capital Deferral Account	1534			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[4]	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[4]	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[4]	1555			$0	Check to Dispose of Account	-$1,387,243.88	$3,605,333	$0
Smart Meter OM&A Variance[4]	1556			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0		$0.00		$0
						$0.00		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0	Check to Dispose of Account	-$1,558,360.02	$5,690,456	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$0	Check to Dispose of Account	$0.00		$0
Excess Expansion Deposits [(a)]	2320	-$177,431		-$527,339	Check to Dispose of Account	-$8,021,484.21	-$7,844,053	$0
Gain on sale-50/60 Eglinton Avenue [(b)]	2320	-$188,109		-$393,507	Check to Dispose of Account	-$11,780,824.34	-$8,575,077	$0
Account receivable credits [(c)]	2208	-$59,893		-$117,070	Check to Dispose of Account	-$3,407,868.19	-$3,290,798	$57,178
					Check to Dispose of Account			

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (
positive figure and credit balance are to have a negative figure) as per the related OEB decision.
Notes:

(a) *Excess Expansion Deposits : This balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, section 9.1 for details of the new account. As the new account is not yet approved, it was not included in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 update evidence. Toronto Hydro has included in this as requested by OEB Staff.*

(b) *Gain on sale-50/60 Eglinton Avenue : As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount. There is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this event.*

(c) *Account receivable credits: As noted in Exhibit 9, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this balance, associated with historical AR credits. here is currently no approved DVA account for this balance, therefore Toronto Hydro did not include this in the original DVA continuity submitted in pre-filed evidence or as part of the 2018 updated evidence. Toronto Hydro has included in this as requested by OEB Staff. Toronto Hydro is not requesting a DVA going forward in association with this balance.*

2020 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2017 Balance (Principal + Interest)	Explanation
3	RSVA - Wholesale Market Service Charge9	1580	$ (85,384.86)	The 2017 approved disposition for CBR class B interest of $85,385 was recorded as part of RSVA - WMS Charge (primary account) for the RRR 2.1.7 Trial Balance. For the purposes of this continuity, the interest component has been reported in the Sub-account CBR class B line. The amount corresponds to the interest approved in EB-2016-0254. See offsetting amount below in the Sub-account CBR Class B.
3.2	Variance WMS – Sub-account CBR Class B9	1580	$ 85,385.39	See above.

Billing Determinants

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.
Used 2020 Load Forecast

			A		B		C		D=A-C		E			F =B-C-E (deduct E if applicable)
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kVA**	**Metered kWh for Non-RPP Customers [5] (excluding WMP)**	**Metered kVA for Non-RPP Customers[5] (excluding WMP)**	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kVA for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kVA less WMP consumption (if applicable)**	**Total Metered 2018 kWh for Class A Customers that were Class A for the entire period the GA balance accumulated**	**Total Metered 2018 kWh for Customers that Transitioned Between Class A and B during the period the GA balance accumulated**		**Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	615,118	4,531,218,421	-	120,867,876		-	-	4,531,218,421	-	-	-	**4,531,218,421**	120,867,876
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CI	kWh	85,852	297,763,685	-	1,256,022		-	-	297,763,685	-	-	-	**297,763,685**	1,256,022
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	71,599	2,299,006,608	-	340,748,367		-	-	2,299,006,608	-	-	-	**2,299,006,608**	340,748,367
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	10,417	9,659,470,299	24,899,004	6,675,659,664	17,765,688	51,161,050	107,338	9,608,309,249	24,791,665	172,242,450	171,190,992	**9,264,875,806**	6,332,226,222
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICAT	kVA	430	4,595,446,119	10,406,674	4,411,896,455	10,021,029	430,714	14,192	4,595,015,405	10,392,482	2,849,579,357	801,154,480	**944,281,567**	761,162,617
LARGE USE SERVICE CLASSIFICATION	kVA	38	2,164,924,150	4,600,360	1,908,284,149	4,126,573	275,445,723	503,078	1,889,478,427	4,097,281	1,678,111,033	29,403,915	**181,963,479**	200,769,201
STANDBY POWER SERVICE CLASSIFICATION	kVA		-	-			-	-	-	-	-	-	**-**	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	825	40,588,612	-	118,578		-	-	40,588,612	-	-	-	**40,588,612**	118,578
STREET LIGHTING SERVICE CLASSIFICATION	kVA	1	116,219,746	326,300	116,219,746	326,300	-	-	116,219,746	326,300	-	-	**116,219,746**	116,219,746
Total		**784,280**	**23,704,637,639**	**40,232,337**	**13,575,050,857**	**32,239,590**	**327,037,487**	**624,609**	**23,377,600,153**	**39,607,728**	**4,699,932,841**	**1,001,749,388**	**17,675,917,924**	**7,873,368,628**

[1] Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

[3] Input the allocation as determined in the LRAMVA model. The associated rate riders will be calculated in the EDDVAR model.

[5] If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are

Group 1 Allocation of Balances

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	STANDBY POWER SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	330,703	kWh	63,215	4,154	32,073	134,759	64,111	30,203	0	566	1,621
Smart Metering Entity Charge Variance Account	1551	(738,259)	# of Customers	(587,800)	(82,039)	(68,419)	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(4,346,196)	kWh	(842,412)	(55,358)	(427,415)	(1,786,308)	(854,272)	(351,278)	0	(7,546)	(21,607)
RSVA - Retail Transmission Network Charge	1584	9,204,066	kWh	1,759,387	115,616	892,661	3,750,591	1,784,325	840,599	0	15,760	45,126
RSVA - Retail Transmission Connection Charge	1586	17,882,318	kWh	3,418,263	224,627	1,734,326	7,286,917	3,466,715	1,633,177	0	30,619	87,674
RSVA - Power (excluding Global Adjustment)	1588	(5,646,009)	kWh	(1,094,351)	(71,914)	(555,241)	(2,320,538)	(1,109,759)	(456,335)	0	(9,803)	(28,069)
RSVA - Global Adjustment	1589	(22,861,167)	Non-RPP kWh	(350,953)	(3,647)	(989,399)	(18,386,295)	(2,210,117)	(582,955)	0	(344)	(337,456)
Total of Group 1 Accounts (excluding 1589)		**16,686,623**		**2,716,302**	**135,086**	**1,607,985**	**7,065,421**	**3,351,120**	**1,696,366**	**0**	**29,597**	**84,746**
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(570,202)**	**kWh**	**(146,171)**	**(9,605)**	**(74,163)**	**(298,873)**	**(30,461)**	**(5,870)**	**0**	**(1,309)**	**(3,749)**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**26,678,828**		**4,653,065**	**262,358**	**2,590,641**	**11,172,267**	**5,315,152**	**2,503,979**	**0**	**46,945**	**134,421**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(9,992,205)**		**(1,936,763)**	**(127,272)**	**(982,656)**	**(4,106,846)**	**(1,964,031)**	**(807,613)**	**0**	**(17,349)**	**(49,675)**
Balance of Account 1589 Allocated to Non-WMPs		**(22,861,167)**		**(350,953)**	**(3,647)**	**(989,399)**	**(18,386,295)**	**(2,210,117)**	**(582,955)**	**0**	**(344)**	**(337,456)**

Class A Consumption Data

1 **Please enter the Year the Account 1589 GA Balance was Last Disposed.** 2017

(e.g. If in the 2018 EDR process, you received approval to dispose the GA variance account balance as at December 31, 2016, enter 2016.)

2a **Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from year after the balance was last disposed to 2017)?** Yes

(e.g. If you received approval to dispose the GA account balance as at December 31, 2016, the period the GA accumulated would be 2017.)

2b **Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from year after the balance was last disposed to 2017).** Yes

(e.g. If the CBR Class B balance was last disposed as at December 31, 2016, the period the CBR Class B variance accumulated would be 2017.)

3a **Enter the number of transition customers you had during the period the Account 1589 GA balance accumulated.** 127

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2018 January to June	2018 July to December
Customer 1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	15,237,254	10,750,334
		kVA	37,162	31,849
		Class A/B	A	B
Customer 2	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	70,146,308	75,057,096
		kVA	198,802	199,630
		Class A/B	B	A
Customer 3	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	68,119,407	65,561,674
		kVA	199,249	193,805
		Class A/B	A	B
Customer 4	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	329,125,988	338,347,412
		kVA	698,099	733,007
		Class A/B	B	A
Customer 5	LARGE USE SERVICE CLASSIFICATION	kWh	14,205,212	15,198,704
		kVA	41,746	41,028
		Class A/B	B	A

3b **Enter the number of customers who were Class A during the entire period since the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B).** 278

Class A Customers - Billing Determinants by Customer

Customer	Rate Class		2018
Customer A1	GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFIC	kWh	172,242,450
		kVA	419,165
Customer A2	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASS	kWh	2,849,579,357
		kVA	6,029,167
Customer A3	LARGE USE SERVICE CLASSIFICATION	kWh	1,678,111,033
		kVA	3,329,196

GA Allocation

This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculates specific amounts for each transition customer. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year of the Account 1589 GA Balance Last Disposed	**2017**

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2018	
Total Class B Consumption for Years During Balance Accumulation (Non-RPP Consumption LESS WMP Consumption and Consumption for Class A customers who were Class A for partial and full year)	A	8,363,158,143	8,363,158,143	
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515	
Transition Customers' Portion of Total Consumption	C=B/A	**5.86%**	**7,873,368,628**	-

Allocation of Total GA Balance $

Total GA Balance	D	-$ 24,283,323
Transition Customers Portion of GA Balance	E=C*D	-$ 1,422,156
GA Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 22,861,167

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers**	**Metered Consumption (kWh) for Transition Customers During the Period They Were Class B Customers in 2017**	**% of kWh**	**Customer Specific GA Allocation During the Period They Were a Class B customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 31,215	-$ 2,601
Customer 2		70,146,308	70,146,308	14.32%	-$ 203,677	-$ 16,973
Customer 3		65,561,674	65,561,674	13.39%	-$ 190,365	-$ 15,864
Customer 4		329,125,988	329,125,988	67.20%	-$ 955,652	-$ 79,638
Customer 5		14,205,212	14,205,212	2.90%	-$ 41,246	-$ 3,437
		489,789,515	**489,789,515**	**100.00%**	**-$ 1,422,156**	**-$ 118,513**

CBR B Allocation

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each transition customer. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Please enter the Year the Account 1580 CBR Class B was Last Disposed.	**2017**	**(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

Allocation of total Consumption (kWh) between Class B and Class A/B Transition Customers

		Total	2017	
Total Class B Consumption for Years During Balance Accumulation (Total Consumption Less WMP Consumption and Consumption for Class A who were Class A for the full year)	A	18,165,707,440	18,165,707,440	
All Class B Consumption (i.e. full year or partial year) for Transition Customers	B	489,789,515	489,789,515	
Transition Customers' Portion of Total Consumption	C=B/A	2.70%	17,675,917,924	-

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	D	-$ 586,002
Transition Customers Portion of CBR Class B Balance	E=D*C	-$ 15,800
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	F=D-E	-$ 570,202

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		127				
Customer		**Total Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers**	**Metered Class B Consumption (kWh) for Transition Customers During the Period They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation During the Period They Were a Class B Customer**	**Monthly Equal Payments**
Customer 1		10,750,334	10,750,334	2.19%	-$ 347	-$ 29
Customer 2		70,146,308	70,146,308	14.32%	-$ 2,263	-$ 189
Customer 3		65,561,674	65,561,674	13.39%	-$ 2,115	-$ 176
Customer 4		329,125,988	329,125,988	67.20%	-$ 10,617	-$ 885
Customer 5		14,205,212	14,205,212	2.90%	-$ 458	-$ 38
		489,789,515	**489,789,515**	100.00%	**-$ 15,800**	**-$ 1,317**

CBR B

The purpose of this tab is to calculate the billing determinants for CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The Year the Account 1580 CBR Class B was Last Disposed. 2017 **(Note: Account 1580, Sub-account CBR Class B was established starting in 2015)**

	Total Metered 2018 Consumption Minus WMP		Total Metered 2018 Consumption for Class A customers that were Class A for the entire period CBR Class B balance accumulated		Total Metered 2018 Consumption for Customers that Transitioned Between Class A and B during the period CBR Class B balance accumulated		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh
	kWh	kVA	kWh	kVA	kWh	kVA	kWh	kVA	
RESIDENTIAL SERVICE CLASSIFICATION	4,531,218,421	-	0	0	0	0	4,531,218,421	-	26%
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICA	297,763,685	-	0	0	0	0	297,763,685	-	2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	2,299,006,608	-	0	0	0	0	2,299,006,608	-	13%
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	9,608,309,249	24,791,665	172,242,450	419,165	171,190,992	467,443	9,264,875,806	23,905,058	52%
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	4,595,015,405	10,392,482	2,849,579,357	6,029,167	801,154,480	1,824,160	944,281,567	2,539,155	5%
LARGE USE SERVICE CLASSIFICATION	1,889,478,427	4,097,281	1,678,111,033	3,329,196	29,403,915	82,773	181,963,479	685,312	1%
STANDBY POWER SERVICE CLASSIFICATION	-	-	0	0	0	0	-	-	0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	40,588,612	-	0	0	0	0	40,588,612	-	0%
STREET LIGHTING SERVICE CLASSIFICATION	116,219,746	326,300	0	0	0	0	116,219,746	326,300	1%
Total	23,377,600,153	39,607,728	4,699,932,841	9,777,527	1,001,749,388	2,374,376	17,675,917,924	27,455,825	100%

GROUP 1 Rate Rider Calculations

Please indicate the Rate Rider Recovery Period (in years) | **12**

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588 per instructions

Rate Class (Enter Rate Classes in cells below)	Units	kVA / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	ROUNDED Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ 2,716,302	**0.00060**	0.00060	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	$ 135,086	**0.00045**	0.00045	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ 1,607,985	**0.00070**	0.00070	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,899,004	$ 11,172,267	**0.44256**	0.44260	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,406,674	$ 5,315,152	**0.50375**	0.50370	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,600,360	$ 2,503,979	**0.53684**	0.53680	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ 29,597	**0.00073**	0.00073	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ 84,746	**0.25616**	0.25620	$/kVA
Total			**$ 23,565,113**			

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts for Non-WMP	ROUNDED Rate Rider for Deferral/Variance Accounts for Non-WMP	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	$ -	**-**	-	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	$ -	**-**	-	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	$ -	**-**	-	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	24,791,665	-$ 4,106,846	**- 0.16339**	- 0.16340	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	10,392,482	-$ 1,964,031	**- 0.18640**	- 0.18640	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	4,097,281	-$ 807,613	**- 0.19441**	- 0.19440	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	$ -	**-**	-	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	$ -	**-**	-	$/kVA
Total			**-$ 6,878,490**			

Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP calculated separately in the table above. For all rate classes without WMP customers, balances in Accounts 1580 and 1588 are included in Deferral/Variance Account Rate Riders calculated in the first table above and disposed through a combined Deferral/Variance Account and Rate Rider.

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B	ROUNDED Rate Rider for Sub-account 1580 CBR Class B	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	4,531,218,421	-$ 146,171	**- 0.00003**	- 0.00003	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	297,763,685	-$ 9,605	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,299,006,608	-$ 74,163	**- 0.00003**	- 0.00003	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kVA	23,905,058	-$ 298,873	**- 0.01233**	- 0.01230	$/kVA
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kVA	2,539,155	-$ 30,461	**- 0.01183**	- 0.01180	$/kVA
LARGE USE SERVICE CLASSIFICATION	kVA	685,312	-$ 5,870	**- 0.00845**	- 0.00840	$/kVA
STANDBY POWER SERVICE CLASSIFICATION	kVA	-	$ -	**-**	-	$/kVA
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	40,588,612	-$ 1,309	**- 0.00003**	- 0.00003	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kVA	326,300	-$ 3,749	**- 0.01133**	- 0.01130	$/kVA
Total			**-$ 570,202**			

Rate rider calculated separately only if Class A customers exist during the period the balance accumulated

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment	ROUNDED Rate Rider for RSVA - Power - Global Adjustment	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	120,867,876	-$ 350,953	**- 0.00290**	- 0.00290	$/kWh
COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATI	kWh	1,256,022	-$ 3,647	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	340,748,367	-$ 989,399	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	6,332,226,222	-$ 18,386,295	**- 0.00290**	- 0.00290	$/kWh
GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION	kWh	761,162,617	-$ 2,210,117	**- 0.00290**	- 0.00290	$/kWh
LARGE USE SERVICE CLASSIFICATION	kWh	200,769,201	-$ 582,955	**- 0.00290**	- 0.00290	$/kWh
STANDBY POWER SERVICE CLASSIFICATION	kWh	-	$ -	**-**	-	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	118,578	-$ 344	**- 0.00290**	- 0.00290	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	116,219,746	-$ 337,456	**- 0.00290**	- 0.00290	$/kWh
Total			**-$ 22,861,167**			

Group 2 Rate Riders Development

% to split by Class

		Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	Allocators										
	2017 Distribution Revenue	100.0%	39.7%	3.7%	14.2%	27.0%	8.5%	4.4%	2.0%	0.5%	0.0%
	2020 Revenue Offsets	100.0%	49.2%	4.0%	20.4%	18.3%	3.5%	1.5%	2.3%	0.8%	0.0%
	Stranded Meters	100.0%	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	Monthly Billing Conversion	100.0%	89.6%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Distribution Revenue GS>50 kW	100.0%	0.0%	0.0%	0.0%	63.6%	20.0%	10.5%	4.7%	1.2%	0.0%
	AR Credits	100.0%	83.5%	0.0%	15.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%

Allocation of Balances

		Account Number	Allocators (Drop Down)	Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
1	Stranded Meters	1555	Stranded Meters	- 1,387,244	- 713,195	-	- 441,086	- 232,962	-	-	-	-	-
2	Wireless pole attachments Rev	1508	2020 Revenue Offsets	- 640,825	- 315,551	- 25,503	- 130,871	- 117,301	- 22,483	- 9,513	- 14,612	- 4,992	-
3	Impact for USGAAP (Actuarial loss on OPEB)	1508	2017 Distribution Revenue	48,103,576	19,087,915	1,783,829	6,806,795	12,996,819	4,093,974	2,135,323	953,529	245,391	-
4	IFRS-CGAAP PP&E	1575	2017 Distribution Revenue	- 1,558,360	- 618,371	- 57,789	- 220,512	- 421,044	- 132,628	- 69,176	- 30,890	- 7,950	-
5	CRRRVA	1508	2017 Distribution Revenue	- 77,968,960	- 30,938,757	- 2,891,330	- 11,032,834	- 21,065,970	- 6,635,741	- 3,461,051	- 1,545,533	- 397,744	-
6	Monthly Billing	1508	Monthly Billing Conversion	11,851,321	10,624,432	-	1,226,889	-	-	-	-	-	-
7	External Driven Capital	1508	2017 Distribution Revenue	- 3,170,205	- 1,257,965	- 117,561	- 448,593	- 856,539	- 269,808	- 140,726	- 62,841	- 16,172	-
8	OPEB cash vs accrual	1508	2017 Distribution Revenue	8,080,000	3,206,214	299,631	1,143,343	2,183,087	687,668	358,672	160,165	41,219	-
9	Derecognition	1508	2017 Distribution Revenue	- 34,499,027	- 13,689,512	- 1,279,331	- 4,881,712	- 9,321,087	- 2,936,125	- 1,531,416	- 683,854	- 175,990	-
10	Deferred Gain on disposals	2320	2017 Distribution Revenue	- 11,780,824	- 4,674,733	- 436,869	- 1,667,021	- 3,182,991	- 1,002,636	- 522,952	- 233,524	- 60,098	-
11	Operations Consolidation Plan Sharing Variance	1508	2017 Distribution Revenue	- 73,533,928	- 29,178,898	- 2,726,866	- 10,405,264	- 19,867,695	- 6,258,287	- 3,264,180	- 1,457,620	- 375,119	-
12	Excess Expansion Deposits	2320	Distribution Revenue GS>50 kW	- 8,021,484	-	-	-	- 5,104,215	- 1,607,818	- 838,601	- 374,478	- 96,372	-
13	AR Credits	2208	AR Credits	- 3,407,868	- 2,844,480	-	- 510,430	- 52,044	- 415	-	-	- 499	-
	Total			- 147,933,830	- 51,312,902	- 5,451,788	- 20,561,296	- 45,041,941	- 14,084,299	- 7,343,619	- 3,289,659	- 848,326	

Note: This table lists all forecasted regulatory account balances proposed for clearance by THESL over the 2020-2024 period ($147.9M). The summary of amounts proposed for disposition in Tables 16 and 17, Exhibit X_T9_S01 excludes disposition of amounts described in Exhibit 8, Tab 1, Schedule 1, section 4.7. The continuity schedule (Exhibit X-T9-S01 App A) lists only the regulatory accounts previously approved by the OEB for tracking.

Load / Customers / Devices / Connections Forecast

		Total	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
	2020 Forecast Dist Billing Determinants (Jan - Dec)										
	kVA	40,232,337	NA	NA	NA	24,899,004	10,406,674	4,600,360	326,300	NA	-
	kWh	23,377,600,153	4,531,218,421	297,763,685	2,299,006,608	9,608,309,249	4,595,015,405	1,889,478,427	116,219,746	40,588,612	-
	Number of Customers	784,280	615,118	85,852	71,599	10,417	430	38	1	-	825
	Devices/Connections	177,454	NA	NA	NA	NA	NA	NA	165,274	12,180	-

Rate Rider Calculation

		Account Number	RR Pass-through or not	Proposed Recovery Period (years)	Amount	Allocators	Rate Rider Start Year	Rate Rider End Year	Billing Unit	Residential	CS Muti-Units Residential	GS < 50 kW	GS - 50 to 999 kW	GS > 1,000 to 4,999 kW	Large User =>5,000 kW	Street Lighting	USL (Connections)	USL (Customer)
1	Stranded Meters	1555	Not Pass-through	5.00	- 1,387,244	Stranded Meters	2020	2024	Customers [1]	- 0.02	-	- 0.10	- 0.37	-	-	-	-	-
2	Wireless pole attachments Rev	1508	Not Pass-through	5.00	- 640,825	2020 Revenue Offsets	2020	2024	Cust.+ Usage [1]	- 0.01	-	- 0.00001	- 0.00090	- 0.00040	- 0.00040	- 0.00880	- 0.00002	-
3	Impact for USGAAP (Actuarial loss on OPEB)	1508	Not Pass-through	5.00	48,103,576	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	0.51	0.34	0.00059	0.10300	0.07760	0.09160	0.57640	0.00121	-
4	IFRS-CGAAP PP&E	1575	Not Pass-through	5.00	- 1,558,360	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.02	- 0.01	- 0.00002	- 0.00330	- 0.00250	- 0.00300	- 0.01870	- 0.00004	-
5	CRRRVA	1508	Not Pass-through	5.00	- 77,968,960	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.83	- 0.55	- 0.00096	- 0.16690	- 0.12580	- 0.14840	- 0.93430	- 0.00196	-
6	Monthly Billing	1508	Not Pass-through	5.00	11,851,321	Monthly Billing Conver	2020	2024	Cust.+ Usage [1]	0.28	-	0.00011	-	-	-	-	-	-
7	External Driven Capital	1508	Not Pass-through	5.00	- 3,170,205	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.03	- 0.02	- 0.00004	- 0.00680	- 0.00510	- 0.00600	- 0.03800	- 0.00008	-
8	OPEB cash vs accrual	1508	Not Pass-through	5.00	8,080,000	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	0.09	0.06	0.00010	0.01730	0.01300	0.01540	0.09680	0.00020	-
9	Derecognition	1508	Not Pass-through	5.00	- 34,499,027	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.37	- 0.24	- 0.00042	- 0.07380	- 0.05570	- 0.06570	- 0.41340	- 0.00087	-
10	Deferred Gain on disposals	2320	Not Pass-through	5.00	- 11,780,824	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.12	- 0.08	- 0.00015	- 0.02520	- 0.01900	- 0.02240	- 0.14120	- 0.00030	-
11	Operations Consolidation Plan Sharing Variance	1508	Not Pass-through	5.00	- 73,533,928	2017 Distribution Reve	2020	2024	Cust.+ Usage [1]	- 0.78	- 0.52	- 0.00091	- 0.15740	- 0.11860	- 0.14000	- 0.88120	- 0.00185	-
12	Excess Expansion Deposits	2320	Not Pass-through	5.00	- 8,021,484	Distribution Revenue G	2020	2024	Cust.+ Usage [1]	-	-	-	- 0.04040	- 0.03050	- 0.03600	- 0.22640	- 0.00047	-
13	AR Credits	2208	Not Pass-through	5.00	- 3,407,868	AR Credits	2020	2024	Cust.+ Usage [1]	- 0.08	-	- 0.00004	- 0.00040	-	-	-	-	-

[1] "Customers" means Residential, GS < 50 kW and GS 50 to 999 kW rates recovery are based on $/cust/30 days
[1] "Cust.+Usage" means Residential and CSMUR rates recovery are based on $/cust/30 days and all other Rate classes recovery are based on $/kWh or $/kVA or $/Device or $/Connection

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 191:

Reference(s): Exhibit U, Tab 9, Schedule 1, pp. 2, 12 and Appendix E

a) Please provide, by account (including Group 2 accounts and other balances – i.e. Accounts Receivable credits, deferred gain on disposals), the amount proposed for disposition as part of the current proceeding (showing principal and carrying charges separately) related to forecast 2019 activity. Please provide an estimate of the bill impacts for a typical residential and GS < 50 kW customer of removing the 2019 amounts from the proposed disposition.

b) Please explain Toronto Hydro's proposal with respect to the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA). Specifically, please discuss whether Toronto Hydro intends to seek clearance of the balance in this account as part of the current proceeding (or some future proceeding).

RESPONSE:

a) Refer to Table 1 below for all Group 2 2019 forecasted DVA activity including the related carrying charges being requested for disposition. Refer to Table 2 for 2019 related rate rider activity related to Group 2 accounts.

Table 1: Group 2 Accounts 2019 Activity and balances for clearance ($ Millions)

Group 2 Accounts	OEB accounts	2019 Forecasted		
		Principal Activity	Carrying Charges	Balances for Clearance
Other Regulatory Assets - Sub-Account - CRRRVA	1508	(22.8)	(0.2)	(23.0)
Other Regulatory Assets - Sub-Account - EIP	1508	(0.8)	(0.0)	(0.8)
Other Regulatory Assets - Sub-Account - Derecognition	1508	(12.1)	(0.1)	(12.3)
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	(0.1)	(0.0)	(0.1)
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	4.1	0.0	4.2
Other Regulatory Assets - Sub-Account - OCCP	1508	(19.1)	-	(19.1)
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	2.6	-	2.6
Renewable Generation Connection Funding Adder Deferral Account [(i)]	1533	(2.0)	-	(2.0)
Group 2 Sub-Total		**(50.2)**	**(0.3)**	**(50.5)**

Note: Variance due to rounding may exist.

As noted in Exhibit 9, Tab 1, Schedule 1, page 35, section 4.11 Account 1533 – Renewable Generation Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment variances, Toronto Hydro is seeking approval to clear this account and return the projected total amount to the IESO, not to rate payers and therefore, this amount does not have an impact on rates.

Table 2: Group 2 Accounts 2019 Forecasted Rate rider Activity ($ Millions)

Group 2 Accounts	OEB accounts	2019 Rate Rider		
		Forecasted Principal	Forecasted Carrying charges	Forecasted Balances
Stranded Meter Costs	1555	(4.7)	(0.3)	(5.0)
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	(7.2)	-	(7.2)
Group 2 Sub-Total		**(11.9)**	**(0.3)**	**(12.2)**

Note: Variance due to rounding may exist.

Toronto Hydro's previous application (EB-2014-0116), the OEB approved the disposition of Account 1555 – Stranded Meters and Account 1575 – IFRS USGAAP Transitional PP&E Amounts based on forecasted balances. Toronto Hydro is now requesting true up of these accounts in this application. The rate riders end December 31, 2019 and result in amounts to be returned to customers of $1.4 million for stranded meters and $1.6 million for IFRS USGAAP transitional PP&E amounts.

There is no 2019 forecasted principal activity related to other accounts and balances for which Toronto Hydro is requesting clearance that do not form a part of the existing deferral and variance accounts (i.e. AR credits, excess expansion deposits, gain on sale of property). There is only projected carrying charges in 2019 related to 2018 balances for these accounts.

Refer to Table 3 below with updated Residential and GS<50 kW bill impacts based on assumption of 2019 forecasted amounts being removed from the proposed disposition.

Table 3: Residential and GS<50 kW bill impacts

		Proposed				
	Change in bill	**2020**	**2021**	**2022**	**2023**	**2024**
Residential	$/30 days	-2.97	0.99	1.12	1.40	1.92
	%	**-2.3**	**0.8**	**0.9**	**1.1**	**1.5**
General Service <50 kW	$/30 days	-3.78	2.22	2.82	4.40	4.82
	%	**-1.1**	**0.7**	**0.9**	**1.3**	**1.4**

b) Toronto Hydro has not proposed clearance of 2018 LRAMVA balances as part of the current proceeding. Toronto Hydro intends to file for clearance of these balances in a future application.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 192:

Reference(s): **Exhibit U, Tab 9, Schedule 1, pp. 1-2**
Exhibit U, Tab 1C, Schedule 4
DVA Continuity Schedule (excel)

Preamble:

Toronto Hydro submitted a DVA continuity schedule that presents the audited December 31, 2018 DVA balances. However, it is not clear how each of the accounts in the continuity schedule reconciles to Note 8 of the December 31, 2018 audited financial statements of Toronto Hydro-Electric System Limited. For example, the DVA continuity schedule presents a December 31, 2018 principal and interest balance in the Capital-Related Revenue Requirement Variance Account (CRRRVA) of a credit of $53.8 million whereas Note 8 of the audited financial statements shows a credit of $56.5 million. In addition, the DVA continuity schedule presents a principal and interest balance in the Operating Centres Consolidation Program (OCCP) account of a $53.3 million credit compared to a credit of $61.9 million in Note 8.

a) Please prepare a table that compares each of the December 31, 2018 closing Group 1 and Group 2 account balances as presented in the DVA continuity schedule (principal and interest combined) to the corresponding audited regulatory account balance as presented in Note 8 of the 2018 audited financial statements of Toronto Hydro-Electric System Limited. Please ensure that any groupings of DVA accounts that is done for financial statement purposes can be mapped to the sum of the individual accounts as presented in the DVA continuity schedule.

b) For each variance identified in the table above, please provide an explanation for the variance. Please ensure that the explanation provided outlines the nature of the variance and why a deviation from the audited balance is appropriate / warranted.

c) For any regulatory account balance that is presented in Note 8 of the 2018 audited financial statements but is not included in the DVA continuity schedule provided in the application update, please provide an explanation as to why it has been excluded and why it is appropriate to do so. Please also highlight any balances that are contained within the DVA continuity schedule but are not included in Note 8 of the audited financial statements and provide an explanation as to why that is the case.

RESPONSE:

a) Please refer to Appendix A of this response for the reconciliation between the DVA continuity and the 2018 audited financial statements, note 8 *Regulatory Balances* ("AFS").

b) The accounts for which there are differences in financial reporting, as illustrated in Appendix A, are discussed in Table 1.

Table 1: Variances between DVA Continuity and Financial Statements notes ($ Millions)

Account	DVA Continuity	AFS	Variance	Explanation
CRRRVA	(53.8)	(56.5)	2.7	The balance in the DVA continuity reflects the variance between the 2015-2018 capital related revenue requirement included in rates and the actual capital in-service additions related revenue requirement over the same period, whereas the balance in the Audited Financial Statements reflects the capital related revenue requirement included in rates and the actual rate base related revenue requirement over the period. Toronto Hydro believes that the DVA balance presented in this application is based on the correct interpretation per the OEB's decision in EB-2014-0116. However, for financial reporting purposes the utility considered that in the absence of regulatory precedent on this type of account, an alternative interpretation may be advanced. Management evaluated the alternative and made a decision to recognize the balance on the basis of the alternative interpretation for financial reporting purposes to remain consistent with accounting principles.
50/60 Eglinton	(53.3)	(61.8)	8.5	The AFS includes the net after-tax gain for an additional property at 50/60 Eglinton Avenue. As described in Exhibit 8, Tab 1, Schedule 1, page 11, Toronto Hydro is seeking approval to clear this amount.
IFRS-CGAAP Transition PP&E amounts	5.7	7.0	(1.3)	The variance arises from the different AFS and APH accounting treatment. In the AFS, the entire return on rate base is recorded upon approval of the regulatory account. For the DVA continuity, per APH Article 510, the return on rate base should not be recorded to this account.

c) The following regulatory account balances are presented in the AFS but not in the DVA continuity schedule:

1. Deferred taxes ($1.9 million credit): this regulatory balance relates to both deferred tax amounts reclassified under IFRS 14 *Regulatory Deferral Accounts* and the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of deferred tax assets. Toronto Hydro did not include this balance on the DVA continuity schedule as it will reverse through timing differences in the recognition of deferred tax assets.

2. Smart meters ($0.3 million credit): this regulatory balance relates to the mandatory implementation of smart meters. The related rate rider ended in April 2017 and the balance reflects the residual amount.

3. Development charges ($7.9 million credit): this regulatory balance relates to the excess expansion deposits for which Toronto Hydro is seeking OEB's approval for a deferral variance account. Refer to Exhibit 9, Tab 1, Schedule 1, Section 9.1 for details of the new account. As the new account is not yet approved, it has not been included on the DVA continuity schedule.

All 2018 regulatory account balances reflected in the DVA continuity are presented in the AFS.

U-Staff-192 Appendix A - Reconciliation between DVA Continuity to 2018 Financial Statements note 8
($ Millions)

Line	Per DVA continuity		Principal	Interest	Total
	Group 1 Accounts				
1	LV Variance Account	1550	0.7	-	**0.70**
2	Smart Metering Entity Charge Variance Account	1551	(0.8)	-	**(0.80)**
3	RSVA - Wholesale Market Service Charge	1580	(29.4)	(0.6)	**(30.00)**
4	Variance WMS – Sub-account CBR Class A	1580	-	-	**-**
5	Variance WMS – Sub-account CBR Class B	1580	-	-	**-**
6	RSVA - Retail Transmission Network Charge	1584	17.0	0.3	**17.3**
7	RSVA - Retail Transmission Connection Charge	1586	25.7	0.3	**26.0**
8	RSVA - Power (excluding Global Adjustment)	1588	(8.8)	(0.2)	**(9.0)**
9	RSVA - Global Adjustment	1589	(17.3)	0.5	**(16.8)**
10	Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-	-	**-**
11	Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-	-	**-**
12	Disposition and Recovery/Refund of Regulatory Balances (2011)	1596	-	-	**-**
13	Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	-	-	**-**
14	Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	-	-	**-**
15	Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	-	-	**-**
16	Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	-	-	**-**
17	Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	25.3	(1.0)	**24.3**
18	Comprised of:				
19	Named properties		1.6	-	1.6
20	Foregone revenue		23.1	-	23.1
21	Capital contributions		0.5	-	0.5
22	2016 RARA residual		0.1	(0.1)	-
23	Tax-related variances		0.2	(1.2)	(1.0)
24	LRAM (approved)		(0.2)	0.3	0.1
25	Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	0.1	0.1	**0.2**
26	Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	(6.3)	(0.7)	**(7.0)**
27	Comprised of:				
28	Settlement variances		(6.8)	(0.8)	(7.6)
29	LRAM (approved)		0.4	0.1	0.5
30					
31	**Group 2 Accounts**				
32	Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral		48.1	-	**48.1**
33	Other Regulatory Assets - Sub-Account - CRRRVA		(52.9)	(0.9)	**(53.8)**
34	Other Regulatory Assets - Sub-Account - EIP		(2.2)	-	**(2.2)**
35	Other Regulatory Assets - Sub-Account - Derecognition		(21.0)	(0.8)	**(21.8)**
36	Other Regulatory Assets - Sub-Account - Wireless Attachments		(0.5)	-	**(0.5)**
37	Other Regulatory Assets - Sub-Account - Monthly Billing		7.4	0.2	**7.6**
38	Other Regulatory Assets - Sub-Account - OCCP		(52.8)	(0.5)	**(53.3)**
39	Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual		5.5	-	**5.5**
40	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		-	-	**-**
41	LRAM		27.9	0.5	**28.4**
42	Renewable Generation Connection Funding Adder Deferral Account		(4.3)	-	**(4.3)**
43	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs		3.3	0.3	**3.6**
44	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component		5.7	-	**5.7**

2018 Financial statements, note 8

Debit balances consist of the following:

	Reference (above)	FS notes	DVA Continuity	Difference	Note
OPEB net actuarial loss	line 32	48.1	48.1	-	
LRAM	lines 24, 29, and 41	29.0	29.0	-	
Foregone revenue	line 20	23.2	23.1	0.1	R
IFRS transitional adjustments	line 44	7.0	5.7	1.3	*
OPEB cash versus accrual	line 39	5.4	5.5	(0.1)	R
Stranded meters	line 43	3.6	3.6	-	
Named properties	line 19	1.6	1.6	-	
Capital contributions	line 21	0.5	0.5	-	
Other	line 37	7.5	7.6	(0.1)	R

Credit balances consist of the following:

	Reference (above)	FS notes	DVA Continuity	Difference	Note
Gain on disposal	line 38	(61.8)	(53.3)	(8.5)	*
Capital-related revenue requirement	line 33	(56.5)	(53.8)	(2.7)	*
Derecognition	line 35	(21.8)	(21.8)	-	
Settlement variances	lines 1, 3, 5, 6, 7, 8, 9, 25, and 28	(19.2)	(19.2)	-	
Development charges		(7.9)	N/A		**
Deferred taxes		(1.9)	N/A		**
Tax-related variances	line 23	(1.1)	(1.0)	(0.1)	R
Smart meters		(0.3)	N/A		**
Other	lines 2, 34, 36, 40 and 42	(7.7)	(7.8)	0.1	R

Legend
R = rounding
* = Refer to U-Staff-192 response to part b)
** = Refer to U-Staff-192 response to part c)

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 193:

Reference(s): **Exhibit U, Tab 9, Schedule 1, p. 4**
Exhibit U, Tab 4A, Schedule 3, Appendix C
Exhibit 9, Tab 1, Schedule 1, pp. 7-10
EB-2015-0049, Report of the Ontario Energy Board on Regulatory Treatment of Pension and OPEB Costs

Preamble:

Account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral tracks the actuarial gains and losses related to Toronto Hydro's OPEBs, which the utility is required to report in Other Comprehensive Income for financial reporting purposes, and are never amortized into profit or loss. In approving such DVA accounts, the OEB expected that amounts accumulated within these accounts would off-set over time and therefore would likely never require disposition. However, as part of the Report of the Ontario Energy Board on Regulatory Treatment of Pension and OPEB costs (dated September 14, 2017), the OEB stated that utilities may propose disposition of balances tracked in this account if the amounts do not substantively offset over-time.

As part of the original evidence filed in this proceeding, Toronto Hydro was seeking recovery of the balance in this account on the basis that changes in the underlying actuarial assumptions, in particular, changes in the discount rate, are not expected to substantially offset the actuarial loss incurred to date. Toronto Hydro proceeded to provide extensive analysis to support their claim (Exhibit 9 / Tab 1 / Schedule 1 / pp. 7-10).

Toronto Hydro submitted an updated actuarial valuation for the period 2019-2024 as part of the application update. The valuation resulted in an actuarial gain of $37.2 million that reduced the balance in account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral from the $85.3 million filed as part of the original evidence in this proceeding to $48.1 million as at December 31, 2018.

a) The updated valuation and resulting actuarial gain contradicts the statements made by Toronto Hydro in its original evidence filed in support of its disposition of this account balance. Specifically, the changes in the underlying actuarial assumptions in the most recent actuarial valuation has resulted in an almost 50% reduction in the account balance compared to the original evidence. In this context, please explain whether Toronto Hydro still believes that the balance in account 1508 Other Regulatory Asset – Sub-account – Impact for US GAAP Deferral will not offset over time.

RESPONSE:

a) In its original evidence, Toronto Hydro projected the discount rate used as at December 31, 2017 to increase by 50 basis points and remain stable over the following seven years. If materialized, and if all other actuarial assumptions remained unchanged, the account balance as at December 31, 2017 was projected to reduce by approximately $23.4 million.[1] In its response to interrogatory 9-Staff-152, Toronto Hydro noted that it cannot make reasonable predictions on future changes to mortality rates, demographics, and health cost trend rate. The change in valuation as at December 31, 2018, which also resulted in a reduction to the account balance from

[1] Exhibit 9, Tab 1, Schedule 1, page 9.

the preceding year, accounted for updates to the discount rate and other actuarial variables.

In addition to the discount rate forecast, Toronto Hydro's analysis of the historical account balance trend informs Toronto Hydro's proposal. Please see Table 1 for the continuity of fiscal year end balances and annual changes to the deferral account balances.

Table 1: Deferral Account Balances and Changes ($ Millions)

Year	Balance	Balance Change
2010	30.1	n/a
2011	64.8	34.7
2012	61.5	-3.3
2013	38.8	-22.7
2014	87.3	48.5
2015	81.2	-6.1
2016	60.2	-21.0
2017	85.3	25.1
2018	48.1	-37.2
Average	**61.9**	**2.0**
Total	**n/a**	**+18.0**

Although the valuation in 2018 resulted in an actuarial gain and a reduction to the account balance, the movement has been volatile and the balance increased by $18.0 million or 60 percent since 2010. Net actuarial losses contributed to $32.8 million of this increase.[2] Over the same period, the account balance has not fallen below $30.1 million and has had a $61.9 million balance (on average), with an increasing trend.

[2] See 9-Staff-152 (d) for the drivers of changes to the deferred account balance.

In its report on OPEBs dated September 14, 2017,[3] the OEB stated that, *"[f]or some utilities, the OEB has already approved the use of a deferral account to capture the cumulative actuarial gains or losses in post-retirement benefits. Utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time. This matter was not the focus of this consultation and therefore, the OEB has not made a determination on a generic approach to the regulatory treatment of actuarial gains and losses under IFRS. The OEB will consider the potential need for further analysis and guidance on this matter in due course."*

In its report to the OEB dated May 2, 2016,[4] KPMG stated that *"[r]easonable OPEB costs should be included in customer rates in time periods as close to the time periods to which they relate as is reasonable while recognizing the need for rate stability and predictability."*

Given the significant and sustained account balance, Toronto Hydro is seeking approval to clear the portion of the 2018 balance over the 2020-2024 period based on the average remaining service life of its employees ("EARSL method"). As presented in JTC 4.10, this would result in a clearance of approximately $17.2 million, or $3.44 million annually, over the five-year period ending 2024.

Toronto Hydro proposes that the 2018 balance, less approximately $17.2 million noted above, continue in the deferral account ("residual 2018 balance"). The residual 2018 balance is approximately $30.9 million.

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[3] Report of the OEB – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040), page 13.
[4] KPMG Report to the Ontario Energy Board on Pension and Other Post-Employment Benefit Costs, May 2, 2016, page 88.

Toronto Hydro proposes that future actuarial gains and losses be added to the residual 2018 balance, and that the resulting cumulative balance of these amounts be the subject of future applications, as applicable, also in accordance with the EARSL method.

The EARSL method is consistent with the approach described by KPMG in its OPEB report to the OEB[5] in which it stated: *"If the accounting framework that is used by a utility does not periodically reclassify to net income the component of OPEB costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan."*

Toronto Hydro notes that a regulatory deferral balance can only be recognized if it is determined that it is probable that future revenue in an amount at least equal to the deferred cost will be recovered in rates. It is probable that Toronto Hydro will not be able to continue to recognize this balance in its external financial statements if there is no acceptance by its regulator for the subsequent inclusion of this deferred balance in its rates, resulting in an impairment of the balance.

[5] Report on Pension and Other Post-Employment Benefit Costs, May 2, 2016.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 194:

Reference(s): Exhibit U, Tab 9, Schedule 1, p. 5

Please explain the change as between the original filing and the application update with respect to the "other adjustments" made to the balance in the CRRRVA. Please provide details of how the "other adjustments" were calculated for 2018 and 2019.

RESPONSE:

The change in the "other adjustments" relates to changes in rate base not associated with 2015-2019 in-service additions to be tracked in the CRRRVA. Please refer to 9-Staff-154 for additional information.

The "other adjustments" are calculated based on the difference between the total capital related revenue requirement variance, and the revenue requirement variance captured in below approved accounts:

- CRRRVA, which tracks the revenue requirement variance between approved and actual in-service additions;
- the Derecognition Variance Account, which tracks the revenue requirement variance from approved versus actual derecognition expense; and
- The Externally Driven Capital Variance Account, which captures the revenue requirement variance between approved and actual in-service additions from externally driven projects.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 195:

Reference(s): **Exhibit U, Tab 9, Schedule 1, p. 9**

Preamble:

Toronto Hydro is seeking disposition of a credit balance of $73.5 million with respect to its OCCP account (including forecast for 2019). This account is supposed to accumulate the difference between the estimated net gains on the sale of the 5800 Yonge and 28 Underwriters properties, grossed up for PILs tax savings, that were approved for disposition in Toronto Hydro's 2015-2019 Custom IR proceeding, and the actual net gains on the properties, grossed up for PILs tax savings, that were realized when the properties were actually sold.

a) In Table 12, it is not clear why the estimated net gain that was approved for disposition in Toronto Hydro's 2015-2019 Custom IR proceeding has changed compared to the original filed evidence in this proceeding (i.e. the row titled, "Forecasted total disposition up to 2018" in Table 12). Please advise whether the amount set out in the noted row represent the OEB approved estimated net gain amount from Toronto Hydro's 2015-2019 Custom IR proceeding.

b) Please explain why there is a forecasted amount for 2019. Please advise whether the properties were sold by the end of 2018. If so, why would amounts accrue to this account after 2018?

RESPONSE:

a) In the EB-2014-0116 decision, the OEB approved the disposition of the forecasted proceeds over 34 months from March 1, 2016 to December 31, 2018. At the time application was filed in August 2018, the projected amount to be disposed was $72.5 million as the rider had not expired. At the time of application update in April 2019, the rider had expired and the actual amount disposed was included in the update ($70.4 million).

b) The additional amount recorded in 2019 represents the PILs tax savings (grossed up) resulting from the greater gain than forecasted in the EB-2014-0116 application and carrying charges.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 196:

Reference(s): Exhibit U, Tab 9, Schedule 1, pp. 9-10

Preamble:

Toronto Hydro is seeking disposition of its OPEB cash vs accrual account and has presented the accumulation of the account balance since it was opened in the updated evidence.

a) Please confirm that the first row of Table 13 represents the forecast OPEB costs recovered in rates through OM&A expense for the years specified. If not, then please explain what this amount represents and why it is appropriate to use for purposes of calculating the balance within this DVA account.

b) If the response to the above is yes, please provide reference to Toronto Hydro's 2015-2019 Custom IR proceeding where these amounts were approved (including the exhibit where the amounts can be confirmed). If the amounts cannot be tied directly to the evidence in the application, please explain how Toronto Hydro has determined these amounts for purposes of calculating the annual balance that gets recorded within this account. Please provide all underlying calculations used to determine the amounts used in Table 13.

c) Please provide the supporting calculations used to derive / estimate the annual "capital depreciation collected for OPEB".

RESPONSE:

a) The first row of Table 13 represents the forecasted OPEB costs that would have been recovered in rates through OM&A expense for the years specified had Toronto Hydro recovered the OPEB costs on an accrual basis.

b) The amounts in the first row of Table 13 represent escalations stemming from a 2014 base value which can be found at column 18, row 9 in the file THESL_IRR_4B_01_OEBStaff_79B_20141105 from the 2015 CIR Application.

Please refer to Table 1 below for the details regarding the calculation of amounts used in Table 13 in the update evidence, which is included below for reference purposes – the first column indicating the line number was added to facilitate the references which can be found in Table 1 below.

Exhibit U, Tab 9, Schedule 1, p. 10 of 14, Table 13: Cash versus Accrual Variance ($ Millions)

Line		2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	Total Updated	Original Total
1	Forecasted OPEB costs (OM&A programs)	10.2	10.4	10.6	10.6	10.6	52.4	53.1
2	Estimated Capital Depreciation Collected for OPEB	2.2	2.4	2.6	2.8	3.0	13.0	13.0
3	Amount collected through rates (A)	12.4	12.8	13.2	13.4	13.6	65.4	66.1
4	Less: Cash payments (B)	9.1	10.8	10.9	10.9	8.9	50.6	50.0
5	Difference (C) = (A) – (B)	3.3	2.0	2.3	2.5	4.7	14.8	16.1
6	OpEx/Capex split (D)	56.2%	57.4%	55.0%	55.1%	55.2%		
7	Cash versus accrual variance (C) x (D)	1.8	1.1	1.3	1.3	2.6	8.1	8.9

Note: Rounding differences may exist.

Table 1: Cash versus accrual calculation details

Line	Description	Reference
1	Forecasted OPEB costs on an accrual basis	As noted in the response to IR 9-Staff-159 part (a), the starting point was the 2014 OPEB OM&A, as submitted in THESL_IRR_4B_01_OEBStaff_79B_20141105, column 18, row 9 ($10.0 million). The forecasted OPEB costs for 2015-2019 were escalated using the same yearly escalation factors as those in the base OM&A approved in the Decision and Order EB-2014-0116, namely: for 2015, increase of 2.1% over 2014, and for 2016 through 2019, escalation by the I-X factor for the respective years.
2	Estimated cumulative depreciation of OPEB costs capitalized since 2000	Refer to Appendix A to Toronto Hydro's response to Undertaking JTC4.12 showing how the amount was calculated.
3	Subtotal (accrual basis) (A)	The sum of amounts in lines 1 and 2.
4	Actual payments made in respect to OPEBs (cash basis) (B)	They can be tied to the actuarial valuation reports for the respective years.
5	Difference between accrual basis and cash basis (C) = (A) – (B)	The difference of the amounts in lines 3 and 4.
6	The percentage of OPEB costs allocated to OM&A (D)	Refer to Toronto Hydro's response to the interrogatory 9-Staff-159 part b) re how the percentage of OPEBs cost that is capitalized is determined. The remainder (to 100% of total OPEB costs (gross)) is the percentage that is allocated to OM&A.
7	Accrual versus cash variance related to OM&A (C) x (D)	The product of lines 5 and 6.

For the 2020-2024 rate period, Toronto Hydro proposes a similar methodology with the following differences:

- The capitalized portion of the OPEB costs, that is funded through depreciation, will commence in 2020, on a go-forward basis; and

- Steps 6 and 7 will not be included as Toronto Hydro will be on the Accrual Method for OPEB.

In the OEB's report on Regulatory Treatment of Pension and OPEBs Costs[1], the Board indicated that a utility that capitalizes a material portion of its total pension and OPEB accrual costs might propose an enhanced methodology for determining the reference amount and the appropriate carrying charge to be applied. As Toronto Hydro capitalizes a significant portion of its OPEB costs as part of its total payroll burden, Toronto Hydro proposes the methodology described in Table 2 below. It is Toronto Hydro's understanding that the tracking applies on a go-forward basis from the date the account is established, which in Toronto Hydro's case is January 1, 2020.

Table 2: Accrual versus cash tracking methodology effective January 1, 2020

	2020	2021	2022	2023	2024
OPEB costs (gross)	13.3	13.6	13.9	14.1	14.4
Of which: Forecasted OPEB costs (OM&A programs) (A)	7.3	7.5	7.7	7.8	7.9
Forecasted OPEB costs (capital programs)	6.0	6.1	6.2	6.3	6.5
Estimated Cumulative Depreciation of OPEB costs capitalized starting in 2020 (B)	0.1	0.2	0.4	0.6	0.8
Forecast accrual amounts recovered in rates (C) = (A) + (B)	7.4	7.7	8.1	8.4	8.7
Cash payments[1] (D)	9.2	9.7	10.2	10.6	11.0
Difference between accrual basis and cash basis (E) = (C) – (D)	(1.8)	(2.0)	(2.1)	(2.2)	(2.3)

Note 1: These amounts represent forecasted payments, and they are included here only for the purpose of presenting the methodology. Toronto Hydro will use the actual payments made each year for the purpose of tracking the differences between accrual and cash basis.

[1] EB-2015-0040, Report of the Ontario Energy Board (September 14, 2017) at page 20.

c) The supporting calculation was provided in Appendix A to Toronto Hydro's response to the Undertaking JTC4.12.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 197:

Reference(s): **GA Analysis Workform (excel)**
Exhibit U, Tab 9, Schedule 1, Appendix B

<u>Preamble:</u>

Toronto Hydro completed a GA Analysis Workform in support of its disposition of the December 31, 2018 balance in account 1589.

a) For transparency purposes, please provide an updated GA Analysis Workform such that cell C62 of Note 5 represents the actual transactions recorded to the account during 2018 as presented in the applicant's general ledger. Therefore, it should exclude the impact of the reversal of the principal adjustment that was recorded to account 1589 as part of the 2017 closing balance. The reversal of that principal adjustment should be recorded separately in Note 5 on its own line.

b) Please also update the DVA continuity schedule to remove the reversal of the 2017 principal adjustment from the "Transactions debit / (credit) during 2018" column and record it in the "Principal Adjustment during 2018" column.

c) In regard to the $50 million principal adjustment that was recorded against account 1589 in 2017, Toronto Hydro had explained that it was a result of a flaw in the consumption data used. Please explain what Toronto Hydro has done to ensure a similar error has not repeated in 2018.

d) Please complete and submit the required responses to Appendix A of the GA Analysis Workform Instructions which can be found on the OEB website.

e) As part of Adjustment 4 in Note 5 of the 2018 GA Analysis workform, Toronto Hydro has recorded a reversal of 2017 timing difference that it had identified and presented in Note 5 of its 2017 GA Analysis Workform. The timing difference relates to the lag between when the Class A GA charges from the IESO are received and when they are actually billed to Class A customers. Please advise whether this timing difference exists with respect to the December 2018 Class A GA charges from the IESO.

If so, why has Toronto Hydro not proposed an adjustment in Note 5 of the 2018 GA Analysis Workform to remove the impact of the year-end 2018 timing difference related to Class A GA (i.e. the December 2018 Class A GA charges that it billed to its Class A customers in January 2019)? If required, please quantify and update Note 5 of the GA Analysis Workfrom accordingly.

f) Toronto Hydro presented an adjustment in Note 5 of the 2018 GA Analysis Workform to account for the difference between the actual system losses and billed TLF's. Using the consumption data presented in Note 4 of the GA Analysis Workform, and the difference between the actual and billed loss factors, please provide a reasonability calculation that quantifies and supports the balance of adjustment 7 presented in Note 5 of the 2018 GA Analysis Workform.

g) In the 2017 GA Analysis Workform, Toronto Hydro presented a reconciling adjustment in Note 5 (Adjustment 8) that was necessary in order to account for the fact that "the current month consumption includes true-up of prior period usage. In the GL, the true-up is based on the prior period's corresponding rate, while the GA Analysis Workform uses only the current month's rate".

Toronto Hydro did not propose a similar reconciling adjustment in the 2018 GA Analysis Workform. Please advise whether the condition that gave rise to the reconciling item in 2017 does not exist anymore. If so, please explain why. If the condition still exists, please quantify the impact for 2018 and update the GA Analysis Workform accordingly.

RESPONSE:

a) Toronto Hydro has updated cell C62 of the GA Analysis Workform to represent the actual transactions recorded to the account during 2018 as presented in THESL's general ledger. The principal adjustment that was recorded to account 1589 as part of the 2017 closing balance is shown separately as reconciling item 5. There was no impact to the unresolved difference calculation in Note 6 of the GA Analysis Workform. Please refer to Appendix A to this response.

b) The change has been reflected in tab 2a of the schedule. Please refer to Appendix B of this interrogatory.

c) As noted in the response to Interrogatory 1-Staff-21 in EB-2018-0071, this was an isolated issue, triggered by the introduction of the Fair Hydro Plan. While Toronto Hydro has rigorous controls in place, it also recognizes the opportunity for continuous improvement. In this instance, Toronto Hydro intends to incorporate the principles behind the GA Analysis Workform into its reasonability analysis going forward.

In addition, Toronto Hydro has enacted a number of controls to validate the accuracy of the consumption data including independent validation models and variance analyses, while insuring that any anomalies are investigated.

d) There have been no changes to the Global Adjustment methodology between 2017 and 2018. Please refer to Appendix A of the GA Analysis Workform Instructions filed as part of EB-2018-0071, interrogatory response 1-Staff-6, Appendix A.

e) Toronto Hydro confirms there is no timing difference with respect to the December 2018 Class A GA charges from the IESO. Toronto Hydro has changed its process in 2018 to true-up the Class A GA charges on a quarterly basis and is based on the actual IESO invoice received as noted in EB-2018-0071 IR response 1-Staff-16 part (d).

f) The calculation of the deemed versus actual losses for the non-RPP Class B GA subgroup of customers ("subgroup") included in the GA Analysis Workform is based on the difference in billed and supplied consumption, as presented in Table 1.

Table 1: Loss for the Subgroup 2018

Loss for the Subgroup 2018		Value	Consumption
Billed usage at wholesale rates (grossed-up for deemed loss) [a]	*A*	\$833.7M	9,162 GWh
Supplied [b]	*B*	\$827.5M	9,106 GWh
Loss	*A-B*	\$6.1M [c]	56 GWh

[a] Per Note 4 of the GA Analysis Workform.
[b] IESO delivered consumption and cost for the subgroup.
[c] Per Note 5, adjustment 7 of the GA Analysis Workform.

The loss value provided (\$6.1 million), determined based on the sum of monthly amounts included in the OEB's workform, is consistent with an alternate annual estimate ($5.1 million). The estimate is derived by applying the 2018 annual effective wholesale rate ($0.09099/kWh)[1] to the consumption loss (56 GWh).

g) The true-up process remains the same in 2018. In the GL, the true-up is still based on prior period's corresponding rate, while the GA Analysis Workform only uses the current month's rate. Toronto Hydro did not include a similar reconciling adjustment in 2018 because it amounted to $171. As this does not significantly change the results, the 2018 GA Analysis Workform has not been updated.

[1] Rate is derived by dividing cost of supplied energy ($833.7 million) by the billed energy (9,162 GWh). Both these values are presented in note 4 of the GA Analysis Workform.

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2018		
Total Metered excluding WMP	C = A+B	24,466,430,392	kWh	100%
RPP	A	10,416,743,189	kWh	42.6%
Non RPP	B = D+E	14,049,687,203	kWh	57.4%
Non-RPP Class A	D	5,208,597,011	kWh	21.3%
Non-RPP Class B*	E	8,841,090,192	kWh	36.1%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month ☐

Note 4 **Analysis of Expected GA Amount**

Year 2018

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	849,734,205	850,744,627	842,429,225	841,418,803	0.08777	$ 73,851,328	0.06736	$ 56,677,971	-$ 17,173,358
February	799,751,814	842,429,225	705,359,910	662,682,499	0.07333	$ 48,594,508	0.08167	$ 54,121,280	$ 5,526,772
March	739,653,450	705,359,910	756,475,470	790,769,009	0.07877	$ 62,288,875	0.09481	$ 74,972,810	$ 12,683,935
April	767,838,600	756,475,470	761,171,140	772,534,270	0.09810	$ 75,785,612	0.09959	$ 76,936,688	$ 1,151,076
May	727,410,928	761,171,140	738,400,175	704,639,964	0.09392	$ 66,179,785	0.10793	$ 76,051,791	$ 9,872,006
June	782,233,924	738,400,175	735,320,321	779,154,070	0.13336	$ 103,907,987	0.11896	$ 92,688,168	-$ 11,219,819
July	781,663,293	735,320,321	861,017,528	907,360,500	0.08502	$ 77,143,790	0.07737	$ 70,202,482	-$ 6,941,308
August	822,933,360	861,017,528	868,275,307	830,191,139	0.07790	$ 64,671,890	0.07490	$ 62,181,316	-$ 2,490,573
September	802,911,438	868,275,307	785,460,234	720,096,365	0.08424	$ 60,660,918	0.08584	$ 61,813,072	$ 1,152,154
October	782,253,575	785,460,234	674,331,062	671,124,404	0.08921	$ 59,871,008	0.12059	$ 80,930,892	$ 21,059,884
November	682,530,587	674,331,062	699,869,426	708,068,951	0.12235	$ 86,632,236	0.09855	$ 69,780,195	-$ 16,852,041
December	692,616,487	699,869,426	781,348,434	774,095,495	0.09198	$ 71,201,304	0.07404	$ 57,314,030	-$ 13,887,273
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**9,231,531,663**	**9,278,854,426**	**9,209,458,233**	**9,162,135,470**		**$ 850,789,240**		**$ 833,670,695**	**-$ 17,118,545**

Calculated Loss Factor **1.0363**

Ontario Energy Board

GA Analysis Workform

Note 5 **Reconciling Items**

	Item	Amount	Explanation
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		(74,264,694)	
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year	-	Not applicable as Toronto Hydro ("TH") records the true-up RPP settlement amounts with the IESO on a quarterly basis. The RPP amounts for 2018 are based on the actual IESO invoices received.
2a	Remove prior year end unbilled to actual revenue differences	(1,595,003)	
2b	Add current year end unbilled to actual revenue differences	3,079,023	
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	-	Not applicable.
3b	Add difference between current year accrual/forecast to actual from long term load transfers	-	Not applicable.
4	Remove GA balances pertaining to Class A customers	3,542,616	Due to timing differences between Class A GA charges from the IESO and billings to Class A customers, $3.5M was included in the 2017 RSVA account pertaining to Class A Customers, which reversed in 2018. There is no Class A GA RSVA pertaining to 2018 activity.
5	Significant prior period billing adjustments recorded in current year	50,366,169	Relates to 2017 due to the flaw in consumption data 2017
6	Differences in GA IESO posted rate and rate charged on IESO invoice	-	Not applicable.
7	Differences in actual system losses and billed TLFs	6,122,800	
8	Others as justified by distributor		
9			

Note 6		
	Adjusted Net Change in Principal Balance in the GL	(12,749,088)
	Net Change in Expected GA Balance in the Year Per Analysis	(17,118,545)
	Unresolved Difference	4,369,457
	Unresolved Difference as % of Expected GA Payments to IESO	0.005

Ontario Energy Board

2019 Deferral/Variance Account Workform

version 1.0

Utility Name	Toronto Hydro-Electric System Limited
Service Territory	
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
2 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	1	Complete the DVA continuity schedule. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2018 rate application, DVA balances as at December 31, 2016 were approved for disposition, start the continuity schedule from 2016 by entering the closing 2015 balances in the Adjustments column under 2015. For all Account 1595 sub-accounts, complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2017 regardless of whether the account is being requested for disposition in the current application. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2015) would have information starting in 2015, when the relevant balances approved for disposition were first transferred into Account 1595 (2015). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year.
		2a	If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (e.g. last disposition was for 2015 balances in the 2017 rate application, current balance requested for disposition accumulated from 2016 to 2017), check off the checkbox in cell BS13. If the checkbox is not checked off, then proceed to tabs 3 to 7 and complete the tabs accordingly. If the checkbox is checked off, tab 6 relating to Class A customer consumption will be generated, see step 7 to 10 below for further details. If the checkbox in step 2a is checked off, another checkbox will pop up to the right of the previous checkbox. If you had any Class A customers at any point during the period that the Account 1580, sub-account CBR Class B balance accumulated (e.g. 2016, 2017 or 2016 & 2017), check off the checkbox. If the checkbox is not checked off, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as a part of the general DVA rate rider. If the checkbox is checked off, then tab 6.2 will be generated. This tab will calculate the billing determinants applicable to Account 1580 sub-account CBR Class B, using information inputted in tab 6. See step 12 below for further details. The CBR Class B balance will be allocated in tab 6.2a and the rate rider will be calculated in tab 7.
		2b	Enter the number of utility-specific 1508 sub-accounts that are approved for the utility in the textbox in cell B71. The DVA continuity schedule will generate the number of utility-specific 1508 sub-accounts starting in row 51. Input the name and the balances of the sub-account(s) starting in row 51. If a utility does not have utility-specific 1508 sub-accounts, the generic 1508 sub-account Other will still be listed in the DVA continuity schedule. Check off the "check to dispose of account" checkbox in column BT for sub-accounts requested for disposition.
3. Appendix A	This tab shows the year end balance variances between the continuity schedule	3	Provide an explanation for the variances identified.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	4	Complete the billing determinants table. Note that columns O and P are generated when a utility indicates they have Class A customers in tab 2a. Information in these columns are populated based on data from tab 6
5 - Allocating Def-Var Balances	This tab allocates the DVA balance (except for CBR Class B if Class A customers exist).	5	Review the allocated balances to ensure the allocation is appropriate. Note that the allocations for Account 1589, Account 1580, sub-account CBR Class B will be determined after tabs 6 to 6.2a have been completed.

Ontario Energy Board

2019 Deferral/Variance Account Workform

Instructions

Tab	Tab Details	Step	Instructions
6 - Class A Data Consumption	This is a new tab that is to be completed if there were any Class A customers at any point during the period the GA balance CBR Class B balance accumulated. The tab also considers Class A/B transition customers. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR Class B charges for transition customers (if applicable).	6	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that the GA balance accumulated. Under #1, enter the year for which the Account 1589 GA balance was last disposed.
		7	Under #2a, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If no, proceed to #3b in step 9. If yes, #2b and tab 6.1a. will be generated. Proceed to #2b. Under #2b, indicate whether you had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If no, proceed to #3a in step 8. If yes, tab 6.2a. will be generated. Proceed to #3a in step 8.
		8	Under #3a, enter the number of transition customers during the period the Account 1589 GA balance accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 6.1a. and 6.2a., respectively. Each transition customer identified in tab 6, table 3a will be assigned a customer number and the number will correspond to the same transition customers populated in tabs 6.1a. and 6.2a. The data in tab 6 will also be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
		9	Under #3b, enter the number of customers who were Class A customers during the entire period since the year the Account 1589 GA balance accumulated (i.e. did not transition between Class A and B during the period). A table will be generated based on the number of customers. Complete the table accordingly for each Class A customer identified. This data will be used in the calculation of billing determinants in the allocation of GA and CBR Class B balances to the rate classes, as applicable.
6.1a. - GA Allocation	This tab has been revised. It allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers who contributed to the GA balance but are now Class A customers and former Class A customers who are now Class B customers contributing to the GA balance).	10	This tab is generated when the utility indicates that they have transition customers in tab 6, #2a during the period when the GA balance accumulated. In row 20, enter the total Class B consumption which equals to Non-RPP consumption less WMP consumption and consumption for Class A customers (who were Class A for partial and full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 7.
6.2 - CBR	This is a new tab that calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	11	This tab is generated when the utility checks in tab 2a. that they have Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. The rest of the information in the tab is auto-populated and will be used in the calculation of the CBR Class B rate rider calculated in tab 6.
6.2a - CBR_B Allocation	This is a new tab that allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers who contributed to the balance but are now Class A customers and former Class A customers who are now Class B contributing to the balance).	12	This tab is generated when the utility indicates that they have transition customers in tab 6, #2b during the period where the CBR Class B balance accumulated. In B16 select the year when the balance in CBR Class B was last disposed. In row 20, enter the total Class B consumption which equals to total consumption less WMP consumption and consumption for Class A customers (who were Class A for eiher partial or full year). The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. Note that the transition customers for GA may be different than the transition customers for CBR Class B as this would depend on the period in which the GA and CBR Class B balances accumulated. Any transition customer who is allocated a specific CBR Class B amount is not to be charged the general CBR Class B rate rider.
7 - Calculation of Def-Var RR	This tab calculates all the applicable DVA rate riders.	13	Enter the proposed rate rider recovery period if different than the default 12 month period. For each rate class of each rate rider, select whether the rate rider is to be calculated on a kWh, kW or number of customers basis. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .

Ontario Energy Board

Deferral/Variance Account Workform

This continuity schedule must be completed for each account and sub-account that the utility has approved for use as at Dec. 31, 2017, regardless of whether disposition is being requested for the account. For all accounts, except for Account 1595, start inputting data from the year in which the GL balance was last disposed. For example, if in the 2017 rate application, DVA balances as at December 31, 2015 were approved for disposition, start the continuity schedule from 2015 by entering the approved closing 2014 balance in the Adjustment column under 2014. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). For example, Account 1595 (2014), data should be inputted starting in 2014 when the relevant balances approved for disposition was first transferred into Account 1595 (2014). The DVA continuity schedule currently starts from 2012, if a utility has an Account 1595 with a vintage year prior to 2012, then a separate schedule should be provided starting from the vintage year. For any new accounts that have never been disposed, start inputting data from the year the account was approved to be used.

2012

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550					$0					$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[9]	1580					$0					$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584					$0					$0
RSVA - Retail Transmission Connection Charge	1586					$0					$0
RSVA - Power (excluding Global Adjustment)[12]	1588					$0					$0
RSVA - Global Adjustment [12]	1589					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

2013

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551					$0	$0				$0
RSVA - Wholesale Market Service Charge[9]	1580	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)[12]	1588	$0				$0	$0				$0
RSVA - Global Adjustment [12]	1589	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment 12	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB

Ontario Energy Board

eferral/Variance Account

This continuity schedule must be completed for each account and
Account 1595, start inputting data from the year in which the GL ba
2015 by entering the approved closing 2014 balance in the Adjustn
example, Account 1595 (2014), data should be inputted starting in
has an Account 1595 with a vintage year prior to 2012, then a sepa
approved to be used.

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions(1) Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments(2) during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments(2) during 2014	Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$0	$1,680,006			$1,680,006	$0	$48,585			$48,585
Smart Metering Entity Charge Variance Account	1551	$0	$230,907			$230,907	$0	$10,096			$10,096
RSVA - Wholesale Market Service Charge[9]	1580	$0	-$104,177,755			-$104,177,755	$0	-$4,243,265			-$4,243,265
Variance WMS – Sub-account CBR Class A[9]	1580										
Variance WMS – Sub-account CBR Class B[9]	1580										
RSVA - Retail Transmission Network Charge	1584	$0	$60,297,064			$60,297,064	$0	$1,969,184			$1,969,184
RSVA - Retail Transmission Connection Charge	1586	$0	$28,085,714			$28,085,714	$0	$981,663			$981,663
RSVA - Power (excluding Global Adjustment)[12]	1588	$0	-$18,770,687			-$18,770,687	$0	$0			$0
RSVA - Global Adjustment [12]	1589	$0	$85,657,811			$85,657,811	$0	$2,633,307			$2,633,307
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	-$363,600			-$363,600	$0	-$318,137			-$318,137
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	-$2,483,823			-$2,483,823	$0	$1,563,823			$1,563,823
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$109,729			$109,729	$0	-$261,355			-$261,355
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$95,890			$95,890	$0	-$55,626			-$55,626
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$50,361,255	$0	$0	$50,361,255	$0	$2,328,275	$0	$0	$2,328,275
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	-$35,296,556	$0	$0	-$35,296,556	$0	-$305,032	$0	$0	-$305,032
RSVA - Global Adjustment 12	**1589**	$0	$85,657,811	$0	$0	$85,657,811	$0	$2,633,307	$0	$0	$2,633,307

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions(1) Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments(2) during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments(2) during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$1,680,006	$447,453			$2,127,459	$48,585	$22,355			$70,940
Smart Metering Entity Charge Variance Account	1551	$230,907	-$103,295			$127,611	$10,096	$2,861			$12,957
RSVA - Wholesale Market Service Charge[9]	1580	-$104,177,755	-$53,058,389			-$157,236,144	-$4,243,265	-$1,397,797			-$5,641,062
Variance WMS – Sub-account CBR Class A[9]	1580		$554,306			$554,306	$0	$1,757			$1,757
Variance WMS – Sub-account CBR Class B[9]	1580		$5,967,910			$5,967,910	$0	$19,743			$19,743
RSVA - Retail Transmission Network Charge	1584	$60,297,064	$6,453,241			$66,750,305	$1,969,184	$753,147			$2,722,331
RSVA - Retail Transmission Connection Charge	1586	$28,085,714	$7,451,237			$35,536,950	$981,663	$375,400			$1,357,063
RSVA - Power (excluding Global Adjustment)[12]	1588	-$18,770,687	-$3,662,931			-$22,433,618	$0	-$261,729			-$261,729
RSVA - Global Adjustment [12]	1589	$85,657,811	$8,710,805			$94,368,616	$2,633,307	$1,177,873			$3,811,180
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600	$0			-$363,600	-$318,137	-$48,826			-$366,963
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823	$0			-$2,483,823	$1,563,823	$17,095			$1,580,918
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729	$0			$109,729	-$261,355	$1,308			-$260,047
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$55,626	$1,139			-$54,487
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0			$0	$0	$0			$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595										
Not to be disposed of until a year after rate rider has expired and that balanc											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$50,361,255	-$27,239,665	$0	$0	$23,121,590	$2,328,275	$664,326	$0	$0	$2,992,600
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$35,296,556	-$35,950,470	$0	$0	-$71,247,026	-$305,032	-$513,547	$0	$0	-$818,579
RSVA - Global Adjustment 12	**1589**	$85,657,811	$8,710,805	$0	$0	$94,368,616	$2,633,307	$1,177,873	$0	$0	$3,811,180

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

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)eferral/Variance Account

**This continuity schedule must be completed for each account and
Account 1595, start inputting data from the year in which the GL b
2015 by entering the approved closing 2014 balance in the Adjustn
example, Account 1595 (2014), data should be inputted starting in
has an Account 1595 with a vintage year prior to 2012, then a sepa
approved to be used.**

Account Descriptions	Account Number	2016 Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16	2017 Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 1 Accounts																					
LV Variance Account	1550	$2,127,459	$312,025	$1,192,584		$1,246,899	$70,940	$15,001	$64,774		$21,166	$1,246,899	$394,328	$934,874		$706,353	$21,166	$6,808	$19,906		$8,068
Smart Metering Entity Charge Variance Account	1551	$127,611	-$379,776	$435,919		-$688,084	$12,957	$14,090	$16,147		$10,900	-$688,084	-$113,182	-$308,308		-$492,958	$10,900	-$15,080	-$7,181		$3,001
RSVA - Wholesale Market Service Charge[9]	1580	-$157,236,144	-$26,035,861			-$183,272,005	-$5,641,062	-$1,776,861			-$7,417,923	-$183,272,005	-$25,199,715	-$157,236,144		-$51,235,576	-$7,417,923	-$555,630	-$7,370,570		-$602,984
Variance WMS – Sub-account CBR Class A[9]	1580	$554,306		$554,306		$0	$1,757		$1,757		$0	$0				$0	$0				$0
Variance WMS – Sub-account CBR Class B[9]	1580	$5,967,910	$1,535,334			$7,503,244	$19,743	$14,282	$19,743		$14,282	$7,503,244	$524,231	$5,967,910		$2,059,564	$14,282	$20,888	$85,385		-$50,215
RSVA - Retail Transmission Network Charge	1584	$66,750,305	-$16,414,401			$50,335,904	$2,722,331	$664,278			$3,386,608	$50,335,904	$8,096,178	$66,750,305		-$8,318,223	$3,386,608	-$83,173	$3,456,545		-$153,109
RSVA - Retail Transmission Connection Charge	1586	$35,536,950	-$29,949,890			$5,587,061	$1,357,063	$271,369			$1,628,432	$5,587,061	$8,333,125	$35,536,950		-$21,616,765	$1,628,432	-$278,307	$1,747,948		-$397,823
RSVA - Power (excluding Global Adjustment)[12]	1588	-$22,433,618	-$4,099,996		-$804,747	-$27,338,361	-$261,729	-$265,904			-$527,633	-$27,338,361	-$3,337,116	-$22,433,618		-$8,241,858	-$527,633	-$93,593	-$508,477		-$112,749
RSVA - Global Adjustment [12]	1589	$94,368,616	-$14,088,418		$804,747	$81,084,945	$3,811,180	$1,131,533			$4,942,712	$81,084,945	$56,920,194	$94,368,616		$43,636,523	$4,942,712	$274,057	$4,812,604		$404,166
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	-$363,600		-$363,600		$0	-$366,963	-$26,599	-$393,562		-$0	$0				$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$2,483,823		-$2,483,823		-$0	$1,580,918	-$66,708	$1,514,210		-$0	-$0				-$0	-$0				-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$109,729		$109,729		-$0	-$260,047	-$12,853	-$272,900		$0	-$0				-$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$95,890				$95,890	-$54,487	$966			-$53,521	$95,890		$95,890		-$0	-$53,521		-$53,433		-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0				$0	$0				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$8,704,230	-$45,304,160		$54,008,390	$0	-$28,061	-$131,074		$103,013	$54,008,390	-$13,829,257			$40,179,133	$103,013	-$18,718		-$993,537	-$909,242
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0				$0	$0				$0	$0	$2,791,740			$2,791,740	$0	$142,065			$142,065
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595																				
Not to be disposed of until a year after rate rider has expired and that balanc																					
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$23,121,590	-$80,416,753	-$45,859,045	$0	-$11,436,118	$2,992,600	-$65,468	$819,096	$0	$2,108,037	-$11,436,118	$34,580,526	$23,676,474	$0	-$532,067	$2,108,037	-$600,683	$2,182,727	-$993,537	-$1,668,911
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$71,247,026	-$66,328,336	-$45,859,045	-$804,747	-$92,521,064	-$818,579	-$1,197,000	$819,096	$0	-$2,834,676	-$92,521,064	-$22,339,668	-$70,692,141	$0	-$44,168,591	-$2,834,676	-$874,740	-$2,629,877	-$993,537	-$2,073,076
RSVA - Global Adjustment 12	**1589**	$94,368,616	-$14,088,418	$0	$804,747	$81,084,945	$3,811,180	$1,131,533	$0	$0	$4,942,712	$81,084,945	$56,920,194	$94,368,616	$0	$43,636,523	$4,942,712	$274,057	$4,812,604	$0	$404,166

**For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n**

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eferral/Variance Account

This continuity schedule must be completed for each account and Account 1595, start inputting data from the year in which the GL ba 2015 by entering the approved closing 2014 balance in the Adjustm example, Account 1595 (2014), data should be inputted starting in has an Account 1595 with a vintage year prior to 2012, then a sepa approved to be used.

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	2019 Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 1 Accounts															
LV Variance Account	1550	$706,353	$320,000	$312,025	$0	$714,328	$8,068	$10,579	$5,861	$0	$12,787	$394,328	$9,276	$320,000	$3,511
Smart Metering Entity Charge Variance Account	1551	-$492,958	-$727,042	-$379,776	$0	-$840,224	$3,001	-$1,169	$13,241	$0	-$11,409	-$113,182	-$19,076	-$727,042	$7,667
RSVA - Wholesale Market Service Charge[9]	1580	-$51,235,576	-$4,206,092	-$26,035,862	$0	-$29,405,806	-$602,984	-$497,277	-$498,414	$0	-$601,847	-$25,199,715	-$556,274	-$4,206,092	-$45,573
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	$2,059,564	-$570,685	$1,535,334	$0	-$46,455	-$50,215	$6,908	-$52,680	$0	$9,373	$524,231	$11,862	-$570,686	-$2,489
RSVA - Retail Transmission Network Charge	1584	-$8,318,223	$8,947,315	-$16,414,402	$0	$17,043,495	-$153,109	$200,783	-$205,715	$0	$253,388	$8,096,178	$197,730	$8,947,316	$55,658
RSVA - Retail Transmission Connection Charge	1586	-$21,616,765	$17,363,768	-$29,949,890	$0	$25,696,892	-$397,823	$277,670	-$446,320	$0	$326,167	$8,333,125	$197,868	$17,363,768	$128,299
RSVA - Power (excluding Global Adjustment)[12]	1588	-$8,241,858	-$5,431,100	-$4,904,742	$0	-$8,768,216	-$112,749	-$152,662	-$98,572	$0	-$166,840	-$3,337,116	-$73,995	-$5,431,100	-$92,845
RSVA - Global Adjustment [12]	1589	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,586	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	$0	$0	$0	-$0	$0	$0	$0	-$0	$0	$0	$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	-$0	$0	$0	$0	-$0	-$0	$0	$0	$0	-$0	$0	$0	-$0	-$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	-$0	$0	$0	$0	-$0	$0	$0	$0	$0	$0	$0	$0	-$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	-$0	$0	$0	$0	-$0	-$88	$0	$0	$0	-$88	$0	$0	-$0	-$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$40,179,133	-$14,888,043	$0	$0	$25,291,090	-$909,242	-$91,080	$0	$0	-$1,000,322	$0	$0	$25,291,090	-$1,000,322
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$2,791,740	-$2,695,385	$0	$0	$96,355	$142,065	-$35,114	$0	$0	$106,951	$0	$0	$96,355	$106,951
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	-$6,348,433	$0	$0	-$6,348,433	$0	-$711,779	$0	$0	-$711,779	$0	$0	-$6,348,433	-$711,779
Not to be disposed of until a year after rate rider has expired and that balanc															
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$532,067	-$32,134,222	-$89,120,985	-$50,366,169	$6,088,526	-$1,668,911	-$718,751	-$1,225,388	-$127,586	-$1,289,859	-$4,748,127	$108,829	$10,836,653	-$1,398,688
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$44,168,591	-$8,235,698	-$75,837,313	$0	$23,433,025	-$2,073,076	-$993,140	-$1,282,599	$0	-$1,783,618	-$11,302,151	-$232,609	$34,735,176	-$1,551,009
RSVA - Global Adjustment 12	**1589**	$43,636,523	-$23,898,524	-$13,283,671	-$50,366,169	-$17,344,499	$404,166	$274,390	$57,211	-$127,586	$493,759	$6,554,025	$341,438	-$23,898,523	$152,321

For all OEB-Approved dispositions, please ensure that the disposition ar balances are to have a positive figure and credit balance are to have a n

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If you had any Class A customers at any point during the period that the Account 1589 GA balance accumulated (i.e. from the year the balance was last disposed to 2017), check off the checkbox ☐

If you had Class A customer(s) during this period, Tab 6 will be generated and applicants must complete the information pertaining to Class A customers.

This continuity schedule must be completed for each account and
Account 1595, start inputting data from the year in which the GL ba
2015 by entering the approved closing 2014 balance in the Adjustn
example, Account 1595 (2014), data should be inputted starting in
has an Account 1595 with a vintage year prior to 2012, then a sepa
approved to be used.

		Projected Interest on Dec-31-18 Balances				2.1.7 RRR	
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)**	**Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)**	**Total Interest**	**Total Claim**	**As of Dec 31-18**	**Variance RRR vs. 2018 Balance (Principal + Interest)**
Group 1 Accounts							
LV Variance Account	1550	$7,192	$0	$10,703	$330,703.40	$727,114	-$1
Smart Metering Entity Charge Variance Account	1551	-$18,884	$0	-$11,217	-$738,258.55	-$851,633	-$0
RSVA - Wholesale Market Service Charge[9]	1580	-$94,532	$0	-$140,105	-$4,346,196.35	-$30,093,038	-$85,385
Variance WMS – Sub-account CBR Class A[9]	1580	$0	$0	$0	$0.00	$0	$0
Variance WMS – Sub-account CBR Class B[9]	1580	-$12,826	$0	-$15,316	-$586,001.52	$48,303	$85,385
RSVA - Retail Transmission Network Charge	1584	$201,091	$0	$256,749	$9,204,065.53	$17,296,882	-$0
RSVA - Retail Transmission Connection Charge	1586	$390,251	$0	$518,550	$17,882,317.91	$26,023,060	-$0
RSVA - Power (excluding Global Adjustment)[12]	1588	-$122,064	$0	-$214,909	-$5,646,008.99	-$8,935,056	$0
RSVA - Global Adjustment [12]	1589	-$537,119	$0	-$384,799	-$24,283,321.89	-$16,850,741	-$1
Disposition and Recovery/Refund of Regulatory Balances (2009	1595	$0	$0	-$0	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010	1595	$0	$0	-$0	$0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011	1596	$0	$0			$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012	1595	$0	$0	$0	☐ Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013	1595	$0	$0	-$88	☐ Check to Dispose of Account $0.00	$0	$88
Disposition and Recovery/Refund of Regulatory Balances (2014	1595	$0	$0	$0	☐ Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015	1595	$0	$0	$0	☐ Check to Dispose of Account $0.00	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2016)[7]	1595	$0	$0	-$1,000,322	☐ Check to Dispose of Account $0.00	$24,290,768	$0
Disposition and Recovery/Refund of Regulatory Balances (2017)[7]	1595	$0	$0	$106,951	☐ Check to Dispose of Account $0.00	$203,308	$1
Disposition and Recovery/Refund of Regulatory Balances (2018)[7]	1595	$0	$0	-$711,779	☐ Check to Dispose of Account $0.00	-$7,060,210	$2
Not to be disposed of until a year after rate rider has expired and that balance							
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$186,892	$0	-$1,585,580	-$8,182,700	$4,798,757	$89
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$350,227	$0	-$1,200,781	$16,100,621.45	$21,649,498	$90
RSVA - Global Adjustment 12	**1589**	-$537,119	$0	-$384,799	-$24,283,321.89	-$16,850,741	-$1
					☐ Check to Dispose of Account		

For all OEB-Approved dispositions, please ensure that the disposition ar
balances are to have a positive figure and credit balance are to have a n

		2012										2013									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-12	Transactions(1) Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments(2) during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments(1) during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions(1) Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments(2) during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments(2) during 2013	Closing Interest Amounts as of Dec-31-13
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508		$61,499,000			$61,499,000					$0	$61,499,000	-$22,718,000			$38,781,000	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - EIP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Derecognition	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OCCP	1508					$0					$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518					$0					$0	$0				$0	$0				$0
Misc. Deferred Debits	1525					$0					$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548					$0					$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0					$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572					$0					$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574					$0					$0	$0				$0	$0				$0
RSVA - One-time	1582					$0					$0	$0				$0	$0				$0
Other Deferred Credits	2425					$0					$0	$0				$0	$0				$0
Group 2 Sub-Total			$61,499,000	$0	$0	$61,499,000	$0	$0	$0	$0	$0	$61,499,000	-$22,718,000	$0	$0	$38,781,000	$0	$0	$0	$0	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592				-$2,314,616	-$2,314,616				-$83,852	-$83,852	-$2,314,616				-$2,314,616	-$83,852	-$34,020			-$117,872
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592				-$1,100,000	-$1,100,000				-$34,148	-$34,148	-$1,100,000				-$1,100,000	-$34,148	-$16,169			-$50,317
LRAM Variance Account[11]	**1568**					$0					$0	$0				$0	$0				$0
Total including Account 1568		$0	$61,499,000	$0	-$3,414,616	$58,084,384	$0	$0	$0	-$118,000	-$118,000	$58,084,384	-$22,718,000	$0	$0	$35,366,384	-$118,000	-$50,189	$0	$0	-$168,189
Renewable Generation Connection Capital Deferral /	1531					$0					$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532					$0					$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533					$0					$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534					$0					$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535					$0					$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				$59,226,643	$59,226,643					$0	$59,226,643	-$59,226,643			$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555				-$27,078,565	-$27,078,565				$350,269	$350,269	-$27,078,565	$27,078,565			$0	$350,269	-$350,269			$0
Smart Meter Capital and Recovery Offset Variance -	1555				$0	$0					$0	$0	$16,876,471		-$1,085,160	$15,791,311	$0				$0
Smart Meter OM&A Variance[4]	1556				$22,925,549	$22,925,549					$0	$22,925,549	-$22,925,549			$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557																				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575					$0						$0			$30,506,428	$30,506,428					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576											$0				$0					

Account Descriptions	Account Number	2014 Opening Principal Amounts as of Jan-1-14	2014 Transactions(1) Debit / (Credit) during 2014	2014 OEB-Approved Disposition during 2014	2014 Principal Adjustments(2) during 2014	2014 Closing Principal Balance as of Dec-31-14	2014 Opening Interest Amounts as of Jan-1-14	2014 Interest Jan-1 to Dec-31-14	2014 OEB-Approved Disposition during 2014	2014 Interest Adjustments(2) during 2014	2014 Closing Interest Amounts as of Dec-31-14	2015 Opening Principal Amounts as of Jan-1-15	2015 Transactions(1) Debit / (Credit) during 2015	2015 OEB-Approved Disposition during 2015	2015 Principal Adjustments(2) during 2015	2015 Closing Principal Balance as of Dec-31-15	2015 Opening Interest Amounts as of Jan-1-15	2015 Interest Jan-1 to Dec-31-15	2015 OEB-Approved Disposition during 2015	2015 Interest Adjustments(2) during 2015	2015 Closing Interest Amounts as of Dec-31-15
Group 2 Accounts																					
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$38,781,000	$48,551,000			$87,332,000	$0				$0	$87,332,000	-$6,142,424			$81,189,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	$0				$0	$0				$0	$0	-$2,679,349			-$2,679,349	$0	-$13,714			-$13,714
Other Regulatory Assets - Sub-Account - EIP	1508	$0	$0			$0	$0				$0	$0	-$155,757			-$155,757	$0	$0			$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	$0	$0			$0	$0				$0	$0	-$12,913,378			-$12,913,378	$0	-$41,430			-$41,430
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$0	-$112,142			-$112,142	$0	-$738			-$738	-$112,142	-$100,000			-$212,142	-$738	-$1,780			-$2,518
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$0				$0	$0				$0	$0	$339,784			$339,784	$0	$0			$0
Other Regulatory Assets - Sub-Account - OCCP	1508	$0				$0	$0				$0	$0	-$5,844,028			-$5,844,028	$0	-$66,137			-$66,137
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0				$0	$0				$0	$0	$1,840,000			$1,840,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0	$0				$0	$0				$0
Group 2 Sub-Total		$38,781,000	$48,438,858	$0	$0	$87,219,858	$0	-$738	$0	$0	-$738	$87,219,858	-$25,655,152	$0	$0	$61,564,705	-$738	-$123,061	$0	$0	-$123,799
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616				-$2,314,616	-$117,872	-$34,020			-$151,892	-$2,314,616				-$2,314,616	-$151,892	-$27,603			-$179,495
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000				-$1,100,000	-$50,317	-$16,170			-$66,487	-$1,100,000				-$1,100,000	-$66,487	-$13,114			-$79,601
LRAM Variance Account[11]	**1568**	$0				$0	$0				$0	$0	$9,112,988			$9,112,988	$0	$216,135			$216,135
Total including Account 1568		$35,366,384	$48,438,858	$0	$0	$83,805,241	-$168,189	-$50,928	$0	$0	-$219,117	$83,805,241	-$16,542,164	$0	$0	$67,263,077	-$219,117	$52,357	$0	$0	-$166,760
Renewable Generation Connection Capital Deferral /	1531	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$15,791,311			-$1,387,244	$14,404,067	$0				$0	$14,404,067				$14,404,067	$0				$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557											$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$30,506,428				$30,506,428						$30,506,428			-$1,558,360	$28,948,068					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0						$0				$0					

2016

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions(1) Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments(2) during 2016	Closing Principal Balance as of Dec-31-16	Opening Interest Amounts as of Jan-1-16	Interest Jan-1 to Dec-31-16	OEB-Approved Disposition during 2016	Interest Adjustments(2) during 2016	Closing Interest Amounts as of Dec-31-16
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$81,189,576	-$21,022,000			$60,167,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$2,679,349	-$5,791,209			-$8,470,558	-$13,714	-$54,531			-$68,245
Other Regulatory Assets - Sub-Account - EIP	1508	-$155,757	-$472,141			-$627,897	$0	-$1,154			-$1,154
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$12,913,378	$1,290,093			-$11,623,285	-$41,430	-$169,801			-$211,231
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$212,142	-$100,016			-$312,158	-$2,518	-$2,815			-$5,333
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$339,784	$1,653,589			$1,993,373	$0	$7,871			$7,871
Other Regulatory Assets - Sub-Account - OCCP	1508	-$5,844,028	$14,486,588			$8,642,560	-$66,137	-$11,273			-$77,409
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$1,840,000	$1,131,000			$2,971,000	$0	$0			$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$61,564,705	-$8,824,096	$0	$0	$52,740,609	-$123,799	-$231,702	$0	$0	-$355,502
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$2,314,616		-$2,314,616		$0	-$179,495	-$4,244	-$183,739		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$1,100,000		-$1,100,000		$0	-$79,601	-$2,017	-$81,619		$2
LRAM Variance Account[11]	1568	$9,112,988	$4,319,627	$3,452,615	$1,278,369	$11,258,369	$216,135	$109,612	$131,074		$194,673
Total including Account 1568		$67,263,077	-$4,504,470	$37,999	$1,278,369	$63,998,978	-$166,760	-$128,351	-$134,285	$0	-$160,827
Renewable Generation Connection Capital Deferral /	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	1533	$0	-$1,026,599			-$1,026,599	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	1555	$14,404,067	-$3,102,224			$11,301,843	$0	$110,022			$110,022
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$28,948,068	-$9,933,709			$19,014,359					
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0					

2017

Account Descriptions	Opening Principal Amounts as of Jan-1-17	Transactions(1) Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments(2) during 2017	Closing Principal Balance as of Dec-31-17	Opening Interest Amounts as of Jan-1-17	Interest Jan-1 to Dec-31-17	OEB-Approved Disposition during 2017	Interest Adjustments(2) during 2017	Closing Interest Amounts as of Dec-31-17
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - Deferred IF	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incrementa	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	$60,167,576	$25,093,000			$85,260,576	$0				$0
Other Regulatory Assets - Sub-Account - CRRRVA	-$8,470,558	-$14,277,069			-$22,747,626	-$68,245	-$208,682			-$276,927
Other Regulatory Assets - Sub-Account - EIP	-$627,897	-$698,387			-$1,326,285	-$1,154	-$3,252			-$4,406
Other Regulatory Assets - Sub-Account - Derecognition	-$11,623,285	-$3,870,968			-$15,494,253	-$211,231	-$192,636			-$403,867
Other Regulatory Assets - Sub-Account - Wireless Attachments	-$312,158	-$100,000			-$412,158	-$5,333	-$4,396			-$9,729
Other Regulatory Assets - Sub-Account - Monthly Billing	$1,993,373	$2,024,793			$4,018,166	$7,871	$37,270			$45,142
Other Regulatory Assets - Sub-Account - OCCP	$8,642,560	$18,394,134			$27,036,693	-$77,409	$212,645			$135,235
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	$2,971,000	$1,300,000			$4,271,000	$0	$0			$0
Retail Cost Variance Account - Retail	$0				$0	$0				$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR	$0				$0	$0				$0
Board-Approved CDM Variance Account	$0				$0	$0				$0
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
Group 2 Sub-Total	$52,740,609	$27,865,503	$0	$0	$80,606,113	-$355,502	-$159,051	$0	$0	-$514,552
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$0				$0	$2				$2
LRAM Variance Account[11]	$11,258,369	$9,612,739	$4,810,834		$16,060,274	$194,673	$156,370	$139,236		$211,807
Total including Account 1568	$63,998,978	$37,478,243	$4,810,834	$0	$96,666,387	-$160,827	-$2,680	$139,236	$0	-$302,743
Renewable Generation Connection Capital Deferral /	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral A	$0				$0	$0				$0
Renewable Generation Connection Funding Adder D	-$1,026,599	-$1,400,410			-$2,427,009	$0				$0
Smart Grid Capital Deferral Account	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance -	$11,301,843	-$3,985,516			$7,316,327	$110,022	$109,435			$219,457
Smart Meter OM&A Variance[4]	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[10]	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	$19,014,359	-$6,583,043			$12,431,316					
Accounting Changes Under CGAAP Balance + Return Component[5]	$0				$0					

Account Descriptions	Account Number	2018										Forecast 2019				2019			
		Opening Principal Amounts as of Jan-1-18	Transactions(1) Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(2) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(2) during 2018	Closing Interest Amounts as of Dec-31-18	Forecast Principal Amount - 2019	Forecast Interest Amount - 2019	Closing Principal Balance - Including Forecast 2019	Closing Interest Balance - Including Forecast 2019	Principal Disposition during 2019 - instructed by OEB	Interest Disposition during 2019 - instructed by OEB	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions during 2019	Closing Interest Balances as of Dec 31-18 Adjusted for Dispositions during 2019
Group 2 Accounts																			
Other Regulatory Assets - Sub-Account - Deferred IF	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Incrementa	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0			$0	$0			$0	$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508	$85,260,576	-$37,157,000			$48,103,576	$0				$0			$48,103,576	$0			$48,103,576	$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$22,747,626	-$30,124,132			-$52,871,758	-$276,927	-$630,950			-$907,877	-$22,772,218	-$228,813	-$75,643,977	-$1,136,691			-$75,643,977	-$1,136,691
Other Regulatory Assets - Sub-Account - EIP	1508	-$1,326,285	-$918,437			-$2,244,722	-$4,406	-$30,653			-$35,059	-$833,163	-$6,811	-$3,077,885	-$41,870			-$3,077,885	-$41,870
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$15,494,253	-$5,487,866			-$20,982,120	-$403,867	-$383,862			-$787,730	-$12,135,667	-$121,938	-$33,117,786	-$909,668			-$33,117,786	-$909,668
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	-$412,158	-$100,000			-$512,158	-$9,729	-$8,376			-$18,105	-$100,000	-$11,412	-$612,158	-$29,517			-$612,158	-$29,517
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$4,018,166	$3,332,692			$7,350,858	$45,142	$105,434			$150,576	$4,143,047	$41,629	$11,493,905	$192,205			$11,493,905	$192,205
Other Regulatory Assets - Sub-Account - OCCP	1508	$27,036,693	-$79,824,824			-$52,788,130	$135,235	-$634,606			-$499,371	-$19,060,013	$0	-$71,848,144	-$499,371			-$71,848,144	-$499,371
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$4,271,000	$1,182,000			$5,453,000	$0	$0			$0	$2,627,000	$0	$8,080,000	$0			$8,080,000	$0
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0			$0	$0			$0	$0
Misc. Deferred Debits	1525	$0				$0	$0				$0			$0	$0			$0	$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0			$0	$0			$0	$0
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0			$0	$0			$0	$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0			$0	$0			$0	$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0			$0	$0			$0	$0
RSVA - One-time	1582	$0				$0	$0				$0			$0	$0			$0	$0
Other Deferred Credits	2425	$0				$0	$0				$0			$0	$0			$0	$0
Group 2 Sub-Total		$80,606,113	-$149,097,567	$0	$0	-$68,491,454	-$514,552	-$1,583,015	$0	$0	-$2,097,567	-$48,131,014	-$327,346	-$116,622,468	-$2,424,913	$0	$0	-$116,622,468	-$2,424,913
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0			$0	$0			$0	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0				$0	$2				$2			$0	$2			$0	$2
LRAM Variance Account[11]	**1568**	$16,060,274	$18,290,141	$6,447,545		$27,902,870	$211,807	$410,304	$121,812		$500,299			$27,902,870	$500,299	$12,048,215	$295,181	$15,854,655	$205,118
Total including Account 1568		$96,666,387	-$130,807,426	$6,447,545	$0	-$40,588,584	-$302,743	-$1,172,710	$121,812	$0	-$1,597,265	-$48,131,014	-$327,346	-$88,719,599	-$1,924,611	$12,048,215	$295,181	-$100,767,814	-$2,219,792
Renewable Generation Connection Capital Deferral A	1531	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection OM&A Deferral A	1532	$0				$0	$0				$0			$0	$0			$0	$0
Renewable Generation Connection Funding Adder D	1533	-$2,427,009	-$1,873,867			-$4,300,876	$0				$0	-$2,236,158.79		-$6,537,035	$0			-$6,537,035	$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0			$0	$0			$0	$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$0				$0	$0				$0			$0	$0			$0	$0
Smart Meter Capital and Recovery Offset Variance -	1555	$7,316,327	-$4,029,308			$3,287,019	$219,457	$98,856			$318,313	-$4,674,263	-$318,313	-$1,387,244	$0			-$1,387,244	$0
Smart Meter OM&A Variance[4]	1556	$0				$0	$0				$0			$0	$0			$0	$0
Meter Cost Deferral Account (MIST Meters)[10]	1557	$0				$0	$0				$0			$0	$0			$0	$0
														$0	$0				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575	$12,431,316	- 6,740,859.89			$5,690,456	$0				$0	-$7,248,817		-$1,558,360	$0			-$1,558,360	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576	$0				$0	$0				$0			$0	$0			$0	$0

		Projected Interest on Dec-31-18 Balances					2.1.7 RRR	
Account Descriptions	**Account Number**	**Projected Interest from Jan 1, 2019 to December 31, 2019 on Dec 31 -18 balance adjusted for disposition during 2019 (6)**	**Projected Interest from January 1, 2020 to April 30, 2020 on Dec 31 -17 balance adjusted for disposition during 2019 (6)**	**Total Interest**		**Total Claim**	**As of Dec 31-18**	**Variance RRR vs. 2018 Balance (Principal + Interest)**
Group 2 Accounts								
Other Regulatory Assets - Sub-Account - Deferred IF	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Incrementa	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0		$0.00		$0
Other Regulatory Assets - Sub-Account - Impact for USGAAP Deferral	1508			$0	Check to Dispose of Account	$48,103,576.00	$48,103,576	-$0
Other Regulatory Assets - Sub-Account - CRRRVA	1508	-$1,188,293		-$2,324,983	Check to Dispose of Account	-$77,968,960.17	-$53,779,636	-$0
Other Regulatory Assets - Sub-Account - EIP	1508	-$50,450		-$92,320	Check to Dispose of Account	-$3,170,205.06	-$2,279,781	-$0
Other Regulatory Assets - Sub-Account - Derecognition	1508	-$471,573		-$1,381,241	Check to Dispose of Account	-$34,499,027.38	-$21,769,849	-$0
Other Regulatory Assets - Sub-Account - Wireless Attachments	1508	$850		-$28,667	Check to Dispose of Account	-$640,825.32	-$530,264	-$0
Other Regulatory Assets - Sub-Account - Monthly Billing	1508	$165,211		$357,415	Check to Dispose of Account	$11,851,320.65	$7,501,434	$1
Other Regulatory Assets - Sub-Account - OCCP	1508	-$1,186,413		-$1,685,784	Check to Dispose of Account	-$73,533,927.94	-$53,287,501	$0
Other Regulatory Assets - Sub-Account - OPEB Cash vs. Accrual	1508	$0	$0	$0	Check to Dispose of Account	$8,080,000.00	$5,453,000	$0
Retail Cost Variance Account - Retail	1518			$0	Check to Dispose of Account	$0.00		$0
Misc. Deferred Debits	1525			$0	Check to Dispose of Account	$0.00		$0
Retail Cost Variance Account - STR	1548			$0		$0.00		$0
Board-Approved CDM Variance Account	1567			$0		$0.00		$0
Extra-Ordinary Event Costs	1572			$0		$0.00		$0
Deferred Rate Impact Amounts	1574			$0		$0.00		$0
RSVA - One-time	1582			$0		$0.00		$0
Other Deferred Credits	2425			$0	Check to Dispose of Account	$0.00		$0
Group 2 Sub-Total		-$2,730,668	$0	-$5,155,581		-$121,778,049.22	-$70,589,021	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0		$0.00		-$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$2		$2.17		-$2
LRAM Variance Account[11]	**1568**			$205,118		$0.00	$28,403,169	-$0
Total including Account 1568		-$2,730,668	$0	-$4,950,460		-$121,778,047	-$42,185,852	-$2
Renewable Generation Connection Capital Deferral /	1531			$0		$0.00		$0
Renewable Generation Connection OM&A Deferral A	1532			$0		$0.00		$0
Renewable Generation Connection Funding Adder D	1533			$0		-$6,537,035.00	-$4,300,876	$0
Smart Grid Capital Deferral Account	1534			$0		$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0		$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0		$0.00		$0
Smart Meter Capital and Recovery Offset Variance -	1555			$0	Check to Dispose of Account	-$1,387,243.88	$3,605,333	$0
Smart Meter OM&A Variance[4]	1556			$0		$0.00		$0
Meter Cost Deferral Account (MIST Meters)[10]	1557			$0		$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[5]	1575			$0	Check to Dispose of Account	-$1,558,360.02	5,690,456.49	$0
Accounting Changes Under CGAAP Balance + Return Component[5]	1576			$0	Check to Dispose of Account	$0.00		$0

Ontario Energy Board

2019 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2017 Balance (Principal + Interest)	Explanation
3	RSVA - Wholesale Market Service Charge9	1580	$ (85,384.86)	The 2017 approved disposition for CBR class B interest of $85,385 was recorded as part of RSVA - WMS Charge (primary account) for the RRR 2.1.7 Trial Balance. For the purposes of this continuity, the interest component has been reported in the Sub-account CBR class B line. The amount corresponds to the interest approved in EB-2016-0254. See offsetting amount below in the Sub-account CBR Class B.
3.2	Variance WMS – Sub-account CBR Class B9	1580	$ 85,385.39	See above.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 110:

Reference(s): **Exhibit U, Tab 1A, Schedule 2, p. 5**

Please provide a Bill Impact Table of the Distribution Portion of the bill only for typical customers in all classes.

RESPONSE:

Please refer to Toronto Hydro's response to U-BOMA-121.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 111:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 5**

THESL indicates in 2018, capital expenditures equalled 95 percent of planned expenditures.

What percentage of the original planned/budgeted work was completed in 2018 that contributes to the 95% spend? Please provide the calculation.

RESPONSE:

Toronto Hydro's response to U-Staff-166.3 shows the annual variances in the utility's capital programs relative to the original 2015-2019 Distribution System Plan. As seen in Appendix A to that interrogatory response, all expenditures in 2018 were in programs set out in Toronto Hydro's five-year capital plan proposed in the 2015-2019 CIR Application. Variances at the program level in 2018 and indeed any given year of the plan period are to be expected. They are part of executing a large and dynamic capital program over a five-year period. In approving a cumulative Capital Related Revenue Requirement Variance Account for the 2015-2019 period, the OEB cited Toronto Hydro's need for flexibility in planning and executing its capital investment strategy in order to respond to the various factors that require the shifting work within the Custom IR term.[1]

[1] Decision and Order (December 29, 2015), EB-2014-0116, pages 52-53.

Nevertheless, the work remains consistent with the needs-based priorities and intended outcomes described in the original plan.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 112:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 8, Figure 3

Please provide the number of Box Construction Poles replaced in 2018 and the forecast for 2019.

RESPONSE:

In 2018, Toronto Hydro replaced 282 Box Construction Poles and expects to replace 355 in 2019.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 113:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 8, Figure 4**

a) At the end of 2018, please provide the total number of Network Units that are not watertight.

b) Please provide one table that shows the number of Network Units with Submersible Protectors installed for each of the years 2013 to 2018 and forecast for 2019 to 2024.

RESPONSE:

a) At the end of 2018, the total number of Network Units in service that were not watertight was 685.

b) Please see Table 1 below.

Table 1: Number of Submersible Network Units Installed in Past Years, and Planned & Reactive Change-outs Forecast for Future Years

	Actual[1]						Forecast[2]					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Submersible Network Units Installed	63	97	72	76	80	67	30	47	47	47	47	47

Note 1: The Actual numbers include all submersible units installed, including units installed in response to drivers such as new services and load growth.
Note 2: The Forecast numbers include only planned and reactive change-outs of existing units.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 114:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 12**

Preamble: THESL Indicates it does not have updated asset condition assessment results at this time as it migrated its data – including core asset data – to a new enterprise system partway through 2018 and as a result of this unique situation, the current state assessment of the distribution system assets for 2019 has not been completed as of this submission.

a) Please discuss the historical and current challenges this unique situation creates.

b) Please discuss the challenges this unique situation creates specifically with respect to asset data management.

c) When will updated asset condition assessment results be available?

d) Please provide a listing of the asset data systems that were migrated to the new system.

e) Please discuss if any underlying asset data quality issues were discovered as a result of the data migration.

RESPONSE:

a) The unique situation of data migration to a new enterprise system partway through 2018 required Toronto Hydro to combine the inputs from the two enterprise systems to produce the final updated asset condition assessment ("ACA") results provided in the response to part (c). The resulting challenges were primarily driven by the need to redevelop processes and data workflows for compiling and pre-processing the input data to align with the updated data structures of the new system. The development and testing of these processes and data work flows are time-intensive in nature, necessitating the continuation of work to complete the ACA update past the submission of Exhibit U.

b) Although this unique situation results in additional time and effort for updating asset condition assessment results over the transition period in 2018, over the long term, it allows for more efficient asset data management. The transition to a new enterprise system allowed Toronto Hydro to consolidate multiple legacy systems within the new enterprise system, as detailed in Exhibit 2B, Section E8.4, Page 18. As a result of this change, asset data sources required for asset condition assessment are now housed in the new enterprise system, reducing future efforts for data consolidation.

c) Updated asset condition assessment results are available at this time. Please see Table 1 below.

Table 1: Summary of Current Health Index Distribution (Updated)

Asset Class	Current Health Score				
	HI1	HI2	HI3	HI4	HI5
Overhead Gang operated Switches	846	34	72	3	10
SCADAMATE Switches	1,140	1	40	-	12
Wood Poles	68,130	5,622	19,146	11,419	671
4kV Oil Circuit Breakers (MS)	18	4	90	24	-
KSO Circuit Breakers (TS)	6	4	19	5	-
SF6 Circuit Breakers (TS)	119	8	18	2	2
Vacuum Circuit Breakers (MS & TS)	659	3	6	1	30
Air Magnetic Circuit Breakers (MS & TS)	139	60	262	10	72
Airblast Circuit Breakers (MS & TS)	2	-	191	2	3
Station Power Transformers	88	84	37	12	13
Network Transformers	1,211	286	181	97	17
Network Protectors	1,159	126	327	65	11
Cable Chambers	7,288	946	1,685	394	113
Submersible Transformers	8,270	345	242	135	36
Air-Insulated Padmount Switches	388	14	83	20	34
Vault Transformers	6,738	4,109	734	243	9
Underground Vaults (combined)	1,018	125	90	32	18
ATS Vaults	9	-	-	-	-
CLD Vaults	22	-	-	-	-
CRD Vaults	9	1	2	-	-
Network Vaults	277	103	84	31	18
Submersible Switch Vaults	116	1	-	-	-
URD Vaults	585	20	4	1	-
Padmount Transformers	5,585	623	310	152	19
SF6-Insulated Padmount Switches	517	-	1	-	7
SF6-Insulated Submersible Switches	375	20	10	3	11
Air-Insulated Submersible Switches	764	73	31	5	-

d) For the purposes of asset condition assessment, the asset data systems that were migrated to the new system were the former enterprise asset management (registry) system (i.e. Ellipse) and WMA (i.e. work management application).

e) There were no material asset data quality issues that were discovered as a result of data migration.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 115:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 13, Figure 10

a) Please provide the circuit-kilometres of direct buried cable replaced in 2018.

b) Please provide one table that shows the numerical values for Figure 10 for the years 2013 to 2018 and the forecast for the years 2019 to 2024.

RESPONSE:

a) Toronto Hydro replaced 29 circuit-kilometres of direct buried cable in 2018.

b) Please see Table 1 below.

Table 1: Presence of Direct Buried Cable 2013-2024

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Circuit-km of Cable	1123	1099	979	867	809	780	757	712	670	628	585	542

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 116:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 14, Table 2**

a) Please add a column to the table that shows the previous 3-year Weighted Average Unit Costs.

b) Please provide an excel version of the table in part (a).

RESPONSE:

a) Please refer to Appendix A to this response.

b) Please refer to the excel version of Appendix A to this response. Please note that in reviewing Exhibit U, Tab 1B, Schedule 1, Table 2, Toronto Hydro identified processing errors that necessitate the restatement of certain 2017 and 2018 values. Please find the restated and complete table in Appendix A.

U-AMPCO-116, Appendix A
Reference: Exhibit U, Tab 1B, Schedule 1, Page 14 of 38

Table 2: 2018 Unit Costs

Category	Category (THESL Asset Name)	Per Unit of Measurement (i.e., each, per meter/foot, per kilometre/mile, per hectar, etc.)	2014-2016 3-Yr Weighted Average Unit Cost	2016 Number of Units	2016 Unit Costs (2016)	2017 Number of Units	2017 Unit Costs (2017)	2018 Number of Units	2018 Unit Costs (2018)	Updated 3-Yr Weighted Average Unit Cost
Wooden Pole Replacement	Wooden Poles	Each	$ 7,434	3592	$ 7,538	2526	$ 7,225	2,015	$ 7,101	$ 7,333
UG XLPE Replacement	U-G Pri Cable- XLPE (In Duct)	Meter	$ 96	311,618	$ 96	312342	$ 137	307,765	$ 123	$ 119
Vegetation Management - Tree Trimming		Km	$ 2,111	1,649	$ 2,137.0	1676	$ 2,147	1,364	$ 2,158	$ 2,147
Pole Test and Treat		Each	$ 18	15,986	$ 17.55	14671	$ 18	10,308	$ 18	$ 18
Overhead Line Patrol & IR Scan		Kilometer	$ 44	7,497	$ 44.0	7045	$ 44	7,147	$ 44	$ 44
Vault Inspection	Network Vault Inspection	Each	$ 335	3,090	$ 345.0	3095	$ 355	3,101	$ 365	$ 355
	Submersible Vault Inspection	Each	$ 140	2,770	$ 145.0	3073	$ 155	2,689	$ 165	$ 155
	Building Vault Inspection	Each	$ 309	1,450	$ 320.0	1211	$ 330	1,576	$ 340	$ 330
OH Manual Switches	O-H Switches	Each	$ 21,062	360	$ 26,359	363	$ 20,004	310	$ 23,222	$ 23,184
OH Remote/Motor Operated Switches										
Overhead (Poletop) Transformer Replacement	O-H Transformers	Each	$ 11,761	804	$ 12,220	548	$ 12,034	425	$ 10,771	$ 11,816
Padmount Transformer Replacement	U-G Transformers	Each	$ 21,454	579	$ 23,091	1033	$ 21,003	474	$ 25,619	$ 22,632
Underground (submersible and vault) Transformer Replacement										
Network Transformer Replacement	Network Unit (Tx & Protector)	Each	$ 88,943	63	$ 106,034	62	$ 90,666	59	$ 83,145	$ 93,516
Network Protector Replacement										
Oil Breaker Replacement	Subst Eq Indr Brk	Each	$ 85,242	4	$ 92,313	5	$ 90,719	17	$ 72,461	$ 79,026
SF6 Breaker Replacement										
Vacuum Breaker Replacement										
Station Switchgear (Air) Replacement	Subst Eq Swtch Air	Each	$ 1,529,625	1	$ 1,374,809	2	$ 1,264,981	5	$ 1,141,971	$ 1,201,828

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 117:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 17, Figure 13**

Please provide Figure 13 excluding Major Event Days and Loss of Supply.

RESPONSE:

Please see Figure 1 below.

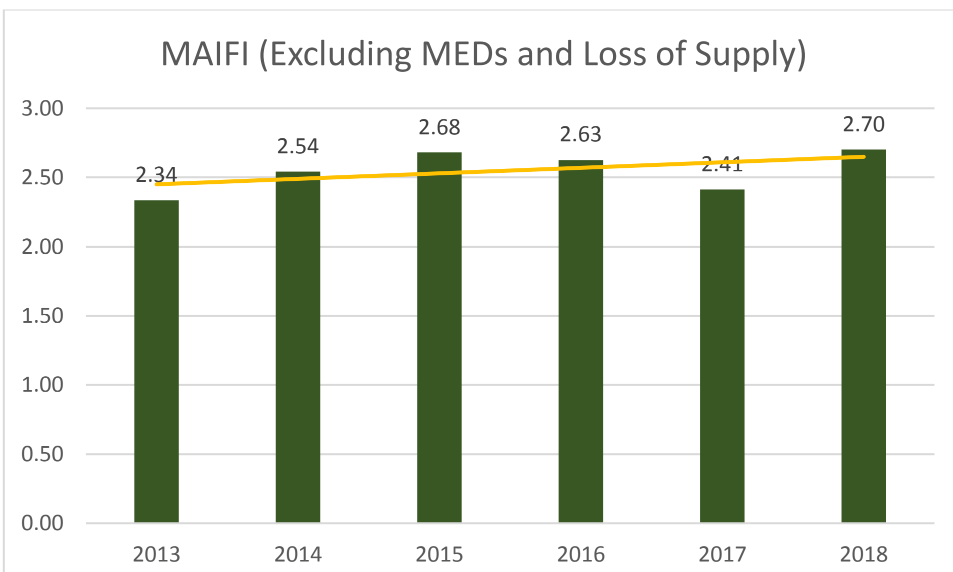


Figure 1: MAIFI Performance Excluding Major Event Days and Loss of Supply (2013 – 2018)

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 118:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 17, Figure 14

a) Please provide the number of outages caused by Defective Equipment in 2018.

b) Please provide the number of outages in 2018 allocated to Overhead, Underground, Network and Stations.

RESPONSE:

a) Please refer to Exhibit U, Tab 1B, Schedule 1, Section 4.1.3, at Page 17, line 5.

b) Please see Table 1 below.

Table 1: 2018 Outages Caused by Defective Equipment

2018 Defective Equipment Outages	
Overhead	146
Underground	285
Stations	10
Network	0

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 119:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 19

Preamble:

THESL indicates that as a result of the migration of the enterprise software system partway through 2018, a longer lead time is required to gather a quality data extract from which the metric's analysis is performed.

a) Please discuss the underlying issue that prevents a quality data extract at this time.

b) Please explain the work needed to resolve this issue.

RESPONSE:

a) The analysis requires gathering data for construction projects completed in 2018. The migration of the enterprise software system partway through 2018 added an extra layer of complexity associated with consolidating and validating the data from two different enterprise software systems. This work has now been completed. However, as noted in Exhibit U, Tab 1B, Schedule 1, at page 19, it takes two to three months to perform the analysis once the dataset is available, which remains the primary reason why the metric cannot be updated at this time.

b) Please see response to part (a).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 120:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 19

Preamble: THESL indicates its Standard Asset Assembly Labour Input is an annual progress report that addresses the status of THESL's framework for standardizing the estimation, management and reporting of construction work progress by the utility's crews. In 2018, THESL migrated enterprise software systems and is now working towards implementing its asset assembly processes in its new environment.

a) When does THESL expect to complete the implementation of its asset assembly processes in the new environment?

b) How does the migration of enterprise software systems specifically impact the estimation, management and reporting of construction activities?

c) How does the migration of enterprise software systems specifically impact the tracking of the total number of labour hours?

RESPONSE:

a) To clarify, Toronto Hydro has implemented its Asset Assembly Units within the new enterprise software systems and is continuing to use these enhanced units to estimate costs for projects carried-out by internal labour resources. The aspect of the asset assembly process that Toronto Hydro is working toward implementing in its new enterprise software system is the more granular data collection and analysis component that will allow the utility to gain additional insights into internal labour productivity on capital projects. Migration to the new system has required revisions to the asset assembly process that are ongoing; once complete, data will need to be collected over time to develop sufficient baselines for enhanced productivity analysis.

b) While there are differences in the software and programs, the migration of enterprise software systems does not substantially alter the estimation, management and reporting methods/principles for construction activities.

c) The migration to the new enterprise software systems does not impact the tracking of the total number of labour hours.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 121:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 31, Figures 28 and 29

a) Please provide the weather impacts that are included in “cumulative weather reliability impacts”.

b) Please provide a breakdown of SAIFI values in Figure 28 by these weather impacts.

c) Please provide a breakdown of SAIDI values in Figure 29 by these weather impacts.

RESPONSE:

a) The “weather impacts” described in Figures 28 and 29 include the following major cause codes: Adverse Weather, Lightning, and Tree Contacts.

b) A breakdown of SAIFI for the three categories can be found in Exhibit U, Tab 1B, Schedule 1, Figure 26.

c) Breakdown of SAIDI for the three categories can be found in Exhibit U, Tab 1B, Schedule 1, Figure 27.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 122:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 31, Figure 32

Please discuss if anything can be done to reduce "Unknown Impacts".

RESPONSE:

Please refer to Toronto Hydro's response to Interrogatory 1B-EP-8, parts (d) and (f).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 123:

Reference(s): Exhibit U, Tab 1C, Schedule 2, p. 29

With respect to Operating Conditions, please define External Services and explain the $11.6 million increase in External Services in 2018 compared to 2017.

RESPONSE:

External Services captures OM&A program work and Revenue Offset activities performed by third parties. The $11.6 million increase in External Services in 2018 was primarily due to costs for emergency power restoration related to major storms, as well as increased distribution system maintenance costs performed by third parties as explained in Exhibit U, Tab 4A, Schedule 1, page 1.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 124:

Reference(s): Exhibit U, Tab 1C, Schedule 5, p. 14

THESL's Annual Information Form for The Year Ended December 31, 2018 provides the following information with respect to Reliability of the Distribution System:

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2018	LDC 2017	CEA 2017(1)
SAIDI	0.98	0.99	7.15
SAIFI	1.48	1.43	2.53
CAIDI	0.66	0.69	2.82

The Note at the bottom of the Table states "Data was extracted from the CEA's 2017 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2018 has not been published by the CEA. Please provide the CEA Reports for 2017 and 2018.

RESPONSE:

Please see Appendices A and B to this response (filed confidentially). /C

APPENDIX 'A'

Canadian Electricity Association, 2017 Service Continuity Data on DSP Report

[Note: A copy of this Appendix has been filed confidentially with the OEB in accordance with the *Practice Direction on Confidential Filings*]

APPENDIX 'B'

Canadian Electricity Association, 2018 Service Continuity Data on DSP Report

[Note: A copy of this Appendix has been filed confidentially with the OEB in accordance with the *Practice Direction on Confidential Filings*]

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 125:

Reference(s): **Exhibit U, Tab 1C, Schedule 5, p. 15**

Please explain the decrease in Large Users from 44 in 2017 to 38 in 2018.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory U-Staff-177.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 126:

Reference(s): **Exhibit U, Tab 2, Schedule 2, pp. 8-16**

For each of the Programs listed in Table 10, Table 11, Table 12, Table 13 and Table 14 (Transformer Stations and Municipal Stations only), please provide the forecast number of assets to be replaced by asset type compared to actuals in 2018.

RESPONSE:

Please see Table 1 for 2018 forecast and actual asset replacements by asset type.

Table 1: Asset Replacement by Segment for 2018 (Forecast and Actual)

Program	Segment	Asset Type	Asset Units	
			2018 Forecast	2018 Actual
Area Conversions	***Rear-Lot Conversion***	Customer Conversions[1]	151	173
	Box Construction Conversion	Poles[2]	1900	586
Underground System Renewal - Horseshoe	***Underground System Renewal Horseshoe***	Underground Switches	43	39
		Underground Transformer	310	251
		Underground Cable (circuit km)	167	156
Network System Renewal	***Legacy Network Equipment Renewal (ATS & RPB)***	ATS & RPB	18	18
	Network Unit Renewal	Network Unit (Transformer and Protector)	20	11
	Network Vault Renewal	Vaults & Roofs	15	11
	Network Circuit Reconfiguration	Reconfigured units & 600V networks	5	1
Overhead System Renewal	***Overhead System Renewal***	Poles	1100	1510
		Overhead Switches	55	90
		Overhead Transformers	575	412
Stations Renewal	***Transformer Stations***	TS Switchgear	1	1
		KSO Oil Circuit Breaker	11	8
	Municipal Stations	MS Switchgear	4	3
		Power Transformers	6	3

Note 1: Beginning with this EB-2018-0165 application, Toronto Hydro now forecasts the volume of Rear Lot conversion activities on a customer basis, rather than on a per asset basis.
Note 2: Similarly to Note 1, Toronto Hydro now tracks Box Construction activities using the dominant unit of poles.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 127:

Reference(s): Exhibit U, Tab 4A, p. 3

a) Please explain why THESL performed less maintenance work in 2018 than in 2017.

b) Was this decrease in work planned?

RESPONSE:

a) As noted in Exhibit 4A, Tab 2, Schedule 4, page 10, at lines 9 and 10, Corrective Maintenance needs can vary both in volume and type of work from year to year as the program is driven by specific deficiencies that are identified on the system each year. Less corrective maintenance work was performed in 2018 compared to 2017 as a result of a reduction in the volume of corrective work requests issued in 2018 to address deficiencies that were identified.

b) Yes, the decrease in corrective maintenance work in 2018 compared to 2017 was planned. As noted in Exhibit 4A, Tab 2, Schedule 4, page 10, at lines 16 to 20 and in Toronto Hydro's response to interrogatory 4A-AMPCO-83 part (b), the work volumes were higher in 2017 because Toronto Hydro had to address a backlog of deficiencies.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 128:

Reference(s): Exhibit U, Tab 4A, p. 2

THESL indicates it hired a lower number of FTEs in 2018 than the utility forecast.

Please provide a table that sets out the forecast number of FTEs for the years 2013 to 2018 compared to actuals in the 2-K FTE categories: Executive, Managerial, Non-Management/Non-Union, Contract for a Defined Term, Society and PWU.

RESPONSE:

For this Application, Toronto Hydro forecasted FTEs for 2018-2020 and provided an extrapolated FTE forecast out to 2024 in response to interrogatory 4A-SEC-87. The actual FTEs for 2015-2017 are filed in OEB Appendix 2-K (Exhibit 4A, Tab 4, Schedule 1) in accordance with the Filing Requirements. With respect to the 2018 forecast vs. 2018 actual FTEs, please see Exhibit U, Tab 4A, Schedule 3 and Toronto Hydro's response to interrogatory U-VECC-87 part (b).

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 129:

Reference(s): Exhibit U, Tab 4A, Schedule 3, p. 2

Please provide the number of vacancies by month for 2018 and the total budget impact of these vacancies in 2018.

RESPONSE:

Table 1 below provides a summary of 2018 headcount vacancies presented by month, and an annualized average FTE total for the year. The total budget impact of the vacancies in 2018 was $10.8 million in gross payroll. Please refer to Toronto Hydro's response to U-VECC-87 part (b) for more information about the staffing variances in 2018.

Table 1: 2018 Headcount Vacancies by Month

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual FTE
-	35	18	25	10	17	125	139	149	135	136	161	79

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 130:

Reference(s): 2B-SEC-51

Please update the excel spreadsheet in 2B-SEC-51 with 2018 actuals.

RESPONSE:

Please see the Excel spreadsheet entitled "U-AMPCO-130 App A." In addition to incorporating 2018 actuals and updated 2019 forecasts, some values included in the original 2B-SEC-51 spreadsheet that have since been recognized as being inaccurate have also been corrected (e.g. the forecast number of box construction poles over 2020-2024 has been changed to reflect the correction noted in Toronto Hydro's response to Undertaking JTC2.18 and the update noted in response to U-SEC-100).

U-AMPCO-130 Appendix A (Updated 2B-SEC-51)

LEGEND	
(green)	EB-2014-0116 Application Numbers Verified
(orange)	EB-2014-0116 Application Numbers Unverified & Corrected Accordingly within this IR Response
(yellow)	Data Populated

	Program/Assets	EB-2014-0116 Application					Actual/Forecast					EB-2018-0105 Proposal				
		2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
E6.1 Underground Circuit Renewal																
	Underground Switches	84	71	74	88	88	47	79	87	39	28	49	45	45	46	46
	Underground Transformer	348	291	305	362	361	105	710	740	251	264	407	380	380	387	387
	Underground Cable (circuit km)	150	126	132	156	156	105	442	173	156	131	103	96	96	98	98
E6.2 Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers																
	PILC Cable (km)	5.39	3.66	2.59	2.66	0.7	1.8	2.3	2	0	0	2.9	5.1	5.3	7.1	7.1
E6.3 Underground Legacy Infrastructure																
	Sachsenwerk Switch and Fuse Units	6	12	12	10	0	22	2	6	3	10	Remaining locations to be addressed through Underground System Renewal				
	Powerlite Switches	0	2	2	2	2	2	1	0	1	3					
	Single Phase Submersible Transformers	0	4	4	4	4	0	0	0	0	16					
	Step Transformers	0	2	2	2	1	0	0	1	1	3					
	Transclosures	6	9	9	9	9	0	9	6	1	20					
	SF Switches	2	1	2	1	0	2	0	1	0	2					
	Cable Chamber Covers	25	375	375	375	350	0	0	9	79	79	200	200	200	200	200
E6.4 Overhead Circuit Renewal																
	Poles	3332	1735	1900	1934	2313	3656	2692	1513	1510	1330	2230	2230	2220	2400	2450
	Overhead Switches	294	160	166	154	207	192	167	120	90	13	130	130	130	160	160
	Overhead Transformers	972	511	478	598	673	940	769	441	412	310	1300	1300	1300	1400	1400
E6.5 Overhead Infrastructure Relocation																
	Poles		32		27	8	81	0	7	11	8	Remaining locations to be addressed through Overhead System Renewal				
	OH Conductor (mts)		5656			3400	12432	0	455	244	0					
	OH Switches		10		6	6	83	0	10	1	9					
	OH Transformers		22		1		43	0	3	1	4					
	Underground Cable Chamber	2		18			0	5	3	5	0					
	Underground Duct (mts)	110		3000	165	200	144	251	524	1541	0					
E6.6 Rear Lot Conversion																
	Pole	63	218	110	31	175	See Notes for 2B-SEC-51. 2,090 customer conversions			173 customer conversions	84 customer conversions	See Notes for 2B-SEC-51. 2,350 customer conversions.				
	Transformer	33	62	48	30	40										
	Manual Switch	16	14	7	5	8										
	Fuse	13	15	16	20	19										
	Riser	13	5	6	5	22										
	Conductor (m)	1910	9314	4632	1796	7886										
	Cable (m)	4583	4305	5476	5598	1566										
E6.7 Box Construction Conversion																
	OH Transformer	201	381	86	175	77	2422 Poles			586 poles	1060 poles	4,100 poles				
	OH Switch	162	301	70	176	85										
	Poles	407	780	277	255	117										
	UG Switch	0	0	0	6	0										
	UG Transformer	21	27	9	52	17										
	OH Conductor (km)	25.5	46.2	11.4	24.4	11.5										
	UG Cable (km)	6	10.4	1.5	5.8	1.4										
E6.8 SCADA-MATE R1 Replacement																
	R1 Switch	72	67	57			40	18	31	87	31	0	0	0	0	0
	RTU	52	49	14			76	19	47	17	15	0	0	0	0	0
E6.9 Network Vault Rebuild Program																
	Vaults	6	9	9	9	9	34			11	18	33				
	Roofs	4	2	2	3	4										
	UG Network Units	11	18	17	20	20	See Network Unit (Transformer and Protector)					0	0	0	0	0
E6.10 Network Unit Renewal Program																
	Network Unit (Transformer and Protector)	40	50	50	50	50	17	25	21	11	18	40	40	40	40	40

U-AMPCO-130 Appendix A (Updated 2B-SEC-51)

LEGEND	
(green)	EB-2014-0116 Application Numbers Verified
(orange)	EB-2014-0116 Application Numbers Unverified & Corrected Accordingly within this IR Response
(yellow)	Data Populated

	Program/Assets	EB-2014-0116 Application					Actual/Forecast					EB-2018-0105 Proposal				
E6.11 Legacy Network Equipment Replacement (ATS & RPB)																
	ATS	3	2	3	2	3	3	3	9	18	7	5	5	3	0	0
	RPB	0	2	2	2	2										
E6.12 Network Circuit Reconfiguration																
	UG Transformers **(600 V Network)**		8				0	0	2	1	2	5				
E6.13 Stations Switchgear Renewal																
	TS Switchgear	0	3	2	2	2	0	0	1	1	1	0	0	1	3	1
	MS Switchgear	3	4	2	1	1	2	0	4	3	2	3	3	2	2	2
E6.14 Stations Power Transformer Renewal																
	Power Transformers	5	19				2	0	6	3	5	2	2	2	2	2
E6.15 Stations Circuit Breaker Renewal																
	KSO Oil Circuit Breaker	10	6	6	7	6	4	2	5	8	7	1	1	2	2	3
E6.16 Stations Control & Monitoring																
	Etobicoke RTU Replacement **(MOSCAD)**	2	5	5	5	5	1	5	7	6	5	3	3	3	3	3
	Scarborough SCADA Installation	0	2	2	2	1	0	0	2	1	2	1	1	1	1	2
	Downtown RTU Replacement **(DACSCAN)**	0	1	1	2	2	0	0	0	1	2	1	3	3	3	4
	Pilot-wire Relay Upgrade	0	6	10	12	12	0	0	1	1	3	1	1	1	1	1
E6.17 Stations Ancillary Systems																
	Air Compressors	4			2		0	0	0	0	0	0	2	0	0	0
	Station Service Power Supply		1				0	0	1	0	2	0	0	2	2	2
	Fire Alarm System			2	1	2	0	0	1	0	1	5				
	Fire Barrier/Suppression System	1	2				0	0	0	1	1	0	0	0	0	0
E6.18 Stations Buildings																
E6.19 Stations DC Battery Replacement																
	Battery System 50 Ah	2	8	5	6	5	3	9	13	13	10	11	13	13	15	15
	Battery System 80 Ah					1										
	Battery System 100 Ah	3	8	7	5	7										
	Battery System 200 Ah			1												
	Battery System 300 Ah		1	2	2											
	Battery System 400 Ah	1	1			2										
E6.20 Reactive Capital																
	Smart Meteres	3930	3930	3930	3930	3930	3247	3004	4058	5350	3930	5585	5685	5785	5885	5985
	RIMS	88	88	88	88	88	108	66	53	178	88					
	Quadlogic	1057	1157	1257	1357	1457	1004	2233	1117	1172	1457					
	Primary Metering Units	8	10	10	10	10	3	23	6	8	10					
E6.21 Worst Performing Feeder																
E6.22 Distribution System Communication Infrastructure																
	IP Data Network Retro-fit (SONET Multiplexers to be augmente	34	11				0	0	0	0	0	45				
	IP Data Network Installation (Without SONET technology Present) (Number of sites)		34				0	0	0	0	0					
	Fiber-Optic Ring Fiber replacement in Toronto (km)	72					0	21	50	8	0	2	2	2	2	2
	Fiber-Optic Ring Fiber replacement in Scarborough (km)	45					54	31	0	10	0					
	Fiber-Optic Ring Expansion in Toronto (km)		54	48			0	0	0	18	0					
	Fiber-Optic Ring Expansion in Scarborough (km)		64	72			0	0	0	2	1					
	New Wireless SCADA SD9 High-Site Deployment (# of Sites)	3	1				0	0	0	0	6	12				
	Wireless SCADA GE Transit to GE SD9 Endpoint Radio Equipment Migration (# of Radios)		194	289			0	0	0	0	270	885				

Please completed the shaded era

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 131:

Reference(s): **2B-SEC-52**

Please update the excel spreadsheet in 2B-SEC-52 with 2018 actuals.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory U-SEC-101.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 132:

Reference(s): 2B-AMPCO-52

Please update the excel spreadsheet in 2B-AMPCO-52 with 2018 actuals.

RESPONSE:

Please see the Excel spreadsheet entitled “U-AMPCO-132 App A”. In addition to incorporating 2018 actuals and updated 2019 forecasts, some values included in the original 2B-AMPCO-52 spreadsheet that have since been recognized as being inaccurate have also been corrected.

U-AMPCO-132 Appendix A

	Assets Replaced		# units replaced						# units replaced				
	Asset Class	Population EB-2014-0116	2015	2016	2017	2018	2019	Population 2020	2020	2021	2022	2023	2024
1	Air Insulated Submersible Switches												
2	SF-6 Insulated Submersible Switches												
3	SF-6 Insulated Padmount Switches	802	47	79	87	39	28		49	45	45	46	46
13	Air -Insulated Padmount Switches												
5	URD Vaults												
6	Submersible Switch Vaults												
7	Network Vaults	1062	34			11	18		33				
8	CRD Vaults												
9	CLD Vaults												
10	ATS Vaults												
11	Underground Vaults (combined)												
4	Padmount Transformers	7160	105	710	740	251	264		407	380	380	387	387
12	Vault Transfomers	13034											
14	Submersible Transformers	9554											
15	Cable Chambers	10902											
16	Network Protectors	1615	17	25	21	11	18		40	40	40	40	40
17	Network Transfomers	1892											
18	Station Power Transfomers	268	2	0	6	3	5		2	2	2	2	2
19	Air Blast Circuit Breaker (MS & TS)	290	0	0	8	13	20		0	0	9	12	28
20	Air Magnetic Circuit Breaker (MS & TS)	627	2	0	2	0	0		2	0	2	11	0
21	Vacuum Circuit Breaker (MS & TS)	675	0	0	0	0	0		0	0	0	0	0
22	Sf6 Circuit Breakers (TS)	201	0	0	0	0	0		0	0	0	0	0
23	KSO Circuit Breaker	59	4	2	5	8	7		1	1	2	2	3
24	4kV Oil Circuit Breaker (MS)	332	10	0	10	14	4		11	17	8	6	10
25	Wood Pole	123280	10283			2096	2390		15,590				
26	SCADAMATE Switches	926											
27	Overhead Gang Operated Switches	1123											
28	Underground Cable	12920	107	444	175	156	131		105.9	101.1	101.3	105.1	105.1
29	Pole Mounted Transformer	30700	940	769	441	412	310		1300	1300	1300	1400	1400

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 133:

Reference(s): 2B-AMPCO-21

Please provide THESL's calculation of the percentage of assets at End of Useful Life at the end of 2018, the percentage of assets to reach Useful Life by the End of Forecast Period (2025), and the percentage of assets not at End of Useful Life.

RESPONSE:

Please see Figure 1 below for the requested information.

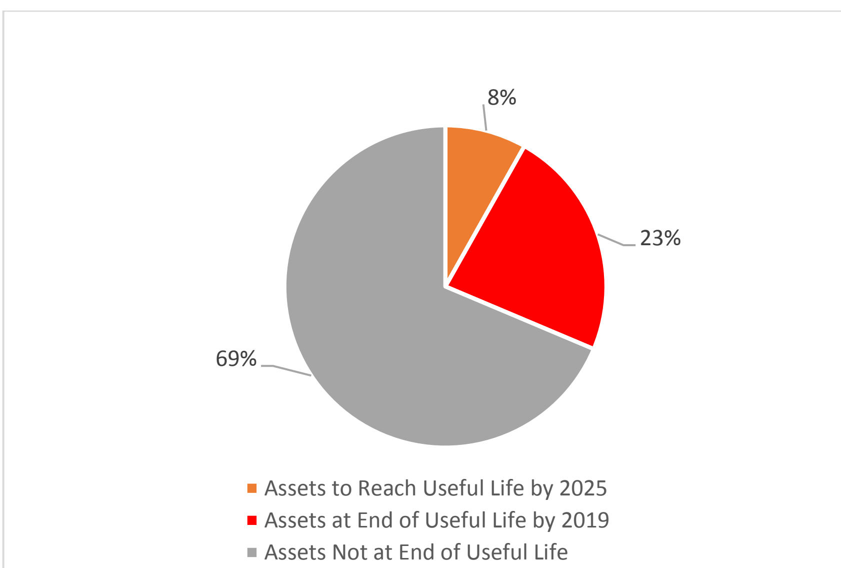


Figure 1: Percentage of Assets Past Useful Life (Updated)

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 121:

Reference(s): **Exhibit U, Tab 1A, Schedule 2, p. 5**

a) Table 3 provides bill increases for each rate class for each year of the 2020-2024 plan. Please provide a similar table which shows the updated distribution charge increase for each rate case for each year of the plan. Please do not include the impact of any rate riders in the table.

b) Please provide a similar table to the one requested in (a) above, but inclusive of the impacts of any rate riders anticipated over the plan term.

RESPONSE:

a) Table 1 below provides a summary for 2020-2024 base distribution bill changes for all rate classes.

Table 1: Base Distribution Bill Change

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	***$/30 days***	0.54	1.37	1.07	1.89	1.83
	%	*1.3*	*3.3*	*2.5*	*4.2*	*3.9*
Competitive Sector Multi-Unit Residential	***$/30 days***	0.20	1.09	0.85	1.50	1.44
	%	*0.6*	*3.3*	*2.5*	*4.3*	*3.9*
General Service <50 kW	***$/30 days***	4.07	3.45	2.69	4.75	4.59
	%	*4.0*	*3.3*	*2.5*	*4.2*	*3.9*
General Service 50-999 kW	***$/30 days***	54.13	56.28	43.87	77.46	74.84
	%	*3.2*	*3.3*	*2.5*	*4.2*	*3.9*

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
General Service 1,000-4,999 kW	***$/30 days***	485.15	463.58	361.18	637.95	616.32
	%	*3.5*	*3.3*	*2.5*	*4.2*	*3.9*
Large Use	***$/30 days***	2569.34	2,388.19	1,860.80	3,286.69	3,175.65
	%	*3.6*	*3.3*	*2.5*	*4.2*	*3.9*
Street Lighting	***$/30 days***	3,986.27	4,052.96	3,174.76	5,596.06	5,444.86
	%	*3.3*	*3.2*	*2.4*	*4.2*	*3.9*
Unmetered Scattered Load	***$/30 days***	-3.34	0.98	0.76	1.35	1.31
	%	*-10.0*	*3.3*	*2.5*	*4.2*	*3.9*

b) Table 2 below provides summary for 2020-2024 distribution bill changes including Rate Riders for all rate classes.

Table 2: Distribution Bill Change including Rate Riders

	Change in bill	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	***$/30 days***	-3.28	0.94	1.07	1.33	1.83
	%	*-7.0*	*2.2*	*2.4*	*2.9*	*3.9*
Competitive Sector Multi-Unit Residential	***$/30 days***	-1.63	0.96	0.85	0.94	1.44
	%	*-4.6*	*2.9*	*2.5*	*2.6*	*3.9*
General Service <50 kW	***$/30 days***	-4.87	2.11	2.69	4.19	4.59
	%	*-4.3*	*1.9*	*2.4*	*3.7*	*3.9*
General Service 50-999 kW	***$/30 days***	-391.69	232.00	43.87	77.46	74.84
	%	*-18.3*	*13.3*	*2.2*	*3.8*	*3.6*
General Service 1,000-4,999 kW	***$/30 days***	-3,829.18	2,462.58	361.18	637.95	616.32
	%	*-20.6*	*16.7*	*2.1*	*3.6*	*3.4*
Large Use	***$/30 days***	-483.69	-933.09	1,860.80	3,286.69	3,175.65
	%	*-0.6*	*-1.1*	*2.3*	*4.0*	*3.7*
Street Lighting	***$/30 days***	-6,410.20	6,161.23	3,174.76	5,596.06	5,444.86
	%	*-5.0*	*5.0*	*2.5*	*4.3*	*4.0*
Unmetered Scattered Load	***$/30 days***	-5.73	0.78	0.76	1.35	1.31
	%	*-16.2*	*2.6*	*2.5*	*4.3*	*4.0*

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 122:

Reference(s): **Letters of Comment;**
Exhibit 1B, Tab 3, Schedule 5

In Toronto Hydro's reply to Mr. Dean Lancaster's letter of comment, it stated:

> *"as a result of a five year plan for 2020-2024, a typical residential customer can expect an annual increase of 1.7% on the delivery line of the bill and less than one-half of one percent on the total electricity bill".*

Please provide what additional items are included in the "delivery line of the bill" in addition to the bare distribution charge and indicate what would be the average annual increase in the distribution charge component alone of the items in the delivery line of the bill.

RESPONSE:

The delivery line on a residential customer's bill includes Toronto Hydro distribution rates (i.e. base distribution rates plus rate riders), Retail Transmission Service Rates, and losses on energy. To clarify, the 1.7 percent increase cited in the reply to Mr. Lancaster's letter refers exclusively to the average annual increase on the distribution rates component (i.e. base distribution rates plus rate riders) of the delivery line. This figure was revised to 1.1 percent in Toronto Hydro's application update.

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 123:

Reference(s): **Letters of Comment;**
Exhibit 1B, Tab 3, Schedule 5, p. 12

Does Toronto Hydro's bill make clear to customers what part of the bare distribution charge is fixed and which part varies with consumption for each rate class in 2019? Is the fixed component of the distribution charge now 100% of that charge for residential and small commercial customers? If so, please explain why the response that the delivery line is partially based on customer's consumption volumes is not misleading customers. Please advise if the delivery line of the bill reflects, in part, customer's consumption of electricity is due to the fact that other components of the delivery charge, such as rate riders, are collected on a volumetric basis. Please explain fully.

RESPONSE:

Toronto Hydro’s bill for Residential and small commercial customers is governed by the OEB’s requirements on bill presentment for these rate classes. The bill shows one line for the Delivery portion of the bill, which is composed of all Toronto Hydro charges (base distribution rates and rate riders) as well as retail transmission rates and losses. It is not broken out into fixed and variable components.

The transition to fully fixed rates for the Residential class is due to be completed as of the 2020 rate year. As such, bills for Residential class customers in 2019 and prior years have both a fixed and a variable component for base distribution rates. Rate riders for residential customers include some that are based on energy consumption and some that are fixed, both historically and through the 2020-2024 period. Small commercial customers continue to have both a fixed and variable portion to their base distribution rates, as OEB policy for fully fixed rates does not currently apply to this class.

The referenced customer response letter provided a full overview of a customer's bill. It also included a link to the rates pages on Toronto Hydro's web site, which provide descriptions of all parts and components of the bill. The letter provides an explanation that some charges on the bill are fixed and some are variable.

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 124:

Reference(s): Letters of Comment;
Exhibit 1B, Tab 3, Schedule 5, p. 12

A number of letters of comment state that the delivery charge should not be based entirely on a fixed annual customer charge, but should also reflect customer's consumption volumes. Has Toronto Hydro considered requesting the OEB to revise the current rate design for residential and small commercial customers to collect some of the delivery charge on a volumetric basis, rather than 100% of the delivery charge from a uniform fixed monthly customer charge? If not, why not, given the evident customer dissatisfaction with the current method? Please show how rate riders and any other non-distribution charge components of the delivery line of the bill are collected. Please address each item separately and in detail.

RESPONSE:

Toronto Hydro's rate design complies with the OEB policy established for all Ontario electricity distributors in EB-2012-0410. Toronto Hydro is not requesting an exemption from that policy in this proceeding.

For the 2018-2024 rate years, the Bill Impact schedules found in Exhibit U, Tab 8, Schedule 1, Appendix A, show, for each rate component on the bill, which ones are fixed (indicated by a "1" in the Volume column) and which are variable (indicated by a value representing the variable component, either kWh for rate classes billed on energy or kVA for rate classes billed on demand).

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 125:

Reference(s): Exhibit 2A, Schedule 1, p. 11 of 12

Please provide a comparable table to Table 7, which shows the same information on Table 7, as shown in the original filing. Please include a column for 2018 actuals.

RESPONSE:

Please see Appendix A to this response.

U-BOMA-125 Appendix A

2018 Actuals, 2019 Bridge (Original) and 2020 Forecast ($ Millions)

	2018 Actual	2019 Bridge Original	2020 Forecast	2020 vs. 2019 Variance ($)	2020 vs. 2019 Variance (%)
Land and Buildings	161.6	166.8	169.8	3.0	1.8%
Other Distribution Assets	434.6	529.7	612.7	83.0	15.7%
General Plant	240.1	240.5	243.0	2.5	1.0%
TS Primary Above 50	37.9	39.0	39.1	0.1	0.3%
Distribution System	213.5	251.0	277.9	26.8	10.7%
Poles, Wires	2,876.9	3,151.0	3,426.9	275.9	8.8%
Contributions and Grants	(156.6)	(254.4)	(322.6)	(68.2)	26.8%
Line Transformers	566.7	645.6	714.2	68.6	10.6%
Services and Meters	344.7	403.9	451.0	47.1	11.7%
Equipment	131.3	135.7	145.9	10.3	7.6%
IT Assets	66.8	77.9	89.0	11.1	14.2%
Gross Assets	**4,917.5**	**5,386.6**	**5,846.8**	**460.2**	**8.5%**
Accumulated Depreciation	(876.9)	(1,116.2)	(1,357.0)	(240.8)	21.6%
Closing PP&E NBV (MIFRS)	**4,040.6**	**4,270.4**	**4,489.8**	**219.4**	**5.1%**

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 126:

Reference(s): Exhibit 2A, Schedule 2, pp. 1-5

Please provide comparable fixed asset continuity schedules for 2014 through 2019, using 2018 actuals.

RESPONSE:

Toronto Hydro declines to provide the requested information for 2014 as this year is out of period for this application. Please note as well that Toronto Hydro was reporting under USGAAP in 2014, whereas financial reporting since 2015 has been under MIFRS.

Please refer to Exhibit 2A, Tab 1, Schedule 2 of the pre-filed evidence for 2015-2017 actual fixed asset continuity schedules and Exhibit U, Tab 2, Schedule 1, Appendix B for 2018 actual and 2019 updated fixed asset continuity schedules.

RESPONSES TO BUILDING OWNERS AND MANAGERS ASSOCIATION INTERROGATORIES

INTERROGATORY 127:

Reference(s): **Exhibit 2B, Section E6.3, p. 28 of 37**
Exhibit 2B, Section E6.3, p. 2, 4, 6, 28, 29, 32 of 37

a) Please provide the amount and dollar volume of the PILC cables to be removed, which are referred to at p28 of 37. What is the revised amount relative to the amount in the original filing? Please show how the change impacts the total spend on underground cables.

b) For each correction shown in the blue pages, please show the equivalent text in the original filing so that the reader can determine what exactly has been changed from the original filing. Please show this information for each "correction" on the blue pages.

RESPONSE:

a) The total spend of $89.7 million on underground cables over 2020-2024 is not impacted by this correction, as the change only applies to the amount of PILC to be removed. Due to a drafting oversight in the original filing, the 23.2 kilometres of PILC cable Toronto Hydro proposed to replace did not correspond to the total proposed PILC removal spending, which was based on the correct value of 27.4 kilometres.

b) Please see Table 1 below for a comparison of the original and corrected information in the referenced section.

Table 1: Comparison of Original and Corrected Information in Exhibit 2B, Section E6.3

Page(s)	Line(s)	Original Information	Corrected Information
2 of 37	12-16	Toronto Hydro recognizes the customer value stemming from the removal of these high risk, led based cables, and plans to invest $89.7 million over the 2020-2024 period to replace less than 2 percent of 1,100 km paper-insulated lead-covered ("PILC") cable and 20 percent of 220 km asbestos-insulated lead-covered ("AILC") cable.	Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $89.7 million over the 2020-2024 period to replace approximately 2.5 percent of 1,100 km paper-insulated lead-covered ("PILC") cable and 24 percent of 220 km asbestos-insulated lead-covered ("AILC") cable.
4 of 37	2	**Table 1: Outcomes & Measures Summary** **Reliability:** Replacing an estimated 23 kilometres of PILC cable that is subject to a high risk of failure	**Table 2: Outcomes & Measures Summary** **Reliability:** Replacing an estimated 27 kilometres of PILC cable that is subject to a high risk of failure.
6 of 37	11-13	Toronto Hydro is planning to remove approximately 20 percent of AILC cable (42 circuit kilometres of 220 kilometres) and 2 percent of PILC cable (23 circuit kilometres of 1,100 kilometres) between 2020 and 2024.	Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between 2020 and 2024.
28 of 37	15	**Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal** [Provided separately below for formatting purposes.]	**Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal** [Provided separately below for formatting purposes.]
29 of 37	8-11	Toronto Hydro has determined that approximately 2 percent of the PILC population is in a critical state and should be addressed through proactive replacement	Toronto Hydro has determined that approximately 2.5 percent of the PILC population is in a critical state and should be addressed through proactive replacement

Page(s)	Line(s)	Original Information	Corrected Information
		during the 2020-2024 period. This 2 percent amounts to 23 circuit-kilometres of PILC, and will trigger replacement of 20 percent of the existing AILC population (43 circuit-kilometres) connected downstream of PILC cable.	during the 2020-2024 period. This 2.5 percent amounts to 27 circuit-kilometres of PILC, and will trigger replacement of 24 percent of the existing AILC population (53 circuit-kilometres) connected downstream of PILC cable.
32 of 37	12-14	Toronto Hydro is planning to remove approximately 20 percent of AILC cable (42 circuit kilometres of 220 kilometres) and 2 percent of PILC cable (23 circuit kilometres of 1,100 kilometres) between 2020 and 2024.	Toronto Hydro is planning to remove approximately 24 percent of AILC cable (53 circuit kilometres of 220 kilometres) and 2.5 percent of PILC cable (27 circuit kilometres of 1,100 kilometres) between 2020 and 2024.

[ORIGINAL] Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal

Asset Class		2020	2021	2022	2023	2024	Total
PILC Cable	*km*	2.2	4.8	4.8	5.7	5.7	**23.2**
AILC Cable	*km*	4.1	8.8	8.8	10.5	10.5	**42.7**

[CORRECTED] Table 8: 2020-2024 Volumes (Forecast): Underground Cable Renewal

Asset Class		2020	2021	2022	2023	2024	Total
PILC Cable	*km*	2.9	5.1	5.3	7.1	7.1	**27.4**
AILC Cable	*km*	5.6	9.9	10.4	13.8	13.8	**53.3**

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 46:

Reference(s):

Please explain, in detail, the process THESL undertook in developing this update. Please provide all written directives given to staff in developing this update. The cover letter indicates that the primary purpose of the update is to provide 2018 financial information. What process did THESL go through in determining what elements of the 2019-2024 forecasts to change given the primary purpose of the update was to provide 2018 financial information?

RESPONSE:

This response explains how Toronto Hydro developed the Application Update. The instructions given to staff developing the update were communicated through various channels, including meetings and workshops, and were consistent with the details provided in this response.

<u>Scope of the Application Update</u>

Toronto Hydro's Application Update was initially and primarily intended as an update of the 2018 bridge year to reflect the availability of audited financial results. In developing the scope of the update, and to ensure a comprehensive update of 2018 financial information, the utility chose to update all of the financial appendices prescribed in the OEB's Filing Requirements, as well as all Deferral and Variance Account balances. Toronto Hydro also included the consequential impacts of 2018 capital expenditure variances on the forecasted 2019 capital expenditures. This was done to provide a complete and updated view of the utility's progress in executing its five-year 2015-2019 Distribution System Plan.

Toronto Hydro also included actual 2018 performance results for all existing and proposed scorecard and service quality metrics where available. The utility's choice to include performance measures was in recognition of the important role of outcomes and performance metrics in the OEB's evaluation of the utility's rate-setting proposals.

The utility's 2020-2024 business plan did not change as a result of the update. For information pertaining to the remaining forecast period (2019-2024), the utility provided updates exclusively where it had made prior update commitments during the proceeding. This included the 2019-2024 Load and Customer Forecasts, Cost Allocation, Rate Design, and Bill Impacts.

In scoping the update, the utility sought to fulfil a number of specific update requests made by OEB Staff and intervenors in interrogatories and the Technical Conference. Please refer to Exhibit U, Tab 1A, Schedule 2, Appendix A for a comprehensive summary of the update commitments and requests fulfilled by the Application Update.

Finally, as summarized at Exhibit U, Tab 6, Schedule 1, Toronto Hydro identified a number of relatively minor changes throughout the update that are expected to have a net impact on the 2020 revenue requirement of an estimated $0.9 million. This is below the utility's materiality threshold. Toronto Hydro is seeking approval for these changes; however, as noted in the update, in the interest of efficiency, the utility decided not to flow these changes through the revenue requirement work form and cost allocation models and has proposed to make these updates as part of the Draft Rate Order process.

Process for Developing the Update

After finalizing the scope of the update, Toronto Hydro gathered the necessary data through its year-end reporting processes, performed additional analysis and forecasting as required (e.g. revised load forecast), and used this information to update the relevant tables, figures and OEB Appendices. The final substantive step was the generation of variance explanations for material variances.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 47:

Reference(s): Exhibit U, Tab 1A, Schedule 2, p. 2

THESL's capital expenditures for 2018 were $435.6 for 2018. Please provide a detailed schedule setting out 2018 in-service additions.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory U-Staff-166.3.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 48:

Reference(s): **Exhibit U, Tab 1A, Schedule 2, p. 5**

Please provide an updated schedule setting out Distribution rate impacts.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory U-BOMA-121.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 49:

Reference(s): Exhibit U, Tab 1B, Schedule 1, pp. 6-7

The number of e-bills as of the end of 2018 is 261,000. What was the forecast for this period? What is THESL's expectation for the test period of the number of e-bills? Please provide the estimated impact on billing costs resulting from customers moving to e-bills.

RESPONSE:

The forecast for 2018 was 251,420 customers on eBills which was within 3.8 percent of the 2018 actual year-end results of 261,372.

Toronto Hydro is forecasting 296,420 customers on eBills at the end of the 2020 test year and as described in Exhibit 2B, Section C2, page 6, the utility aims to have approximately 347,000 customers on eBills by the end of 2024.

Table 1: Estimated Impacts to Billing Costs as a Result of eBill Additions between 2020-2024

	Year				
	2020 Test	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast
Number of Customers on eBills at Year End	296,420	314,420	329,420	340,420	347,420
Forecast of eBill Adoption Growth	21,000	18,000	15,000	11,000	7,000
Forecast Annual Savings per Customer Converted to eBills	$10.48	$10.72	$11.08	$11.32	$11.68
Full Year Cost Savings from eBill Adoption Growth (After First Year)	$220,083	$192,963	$166,202	$124,522	$81,761

Note 1: Differences may exist due to rounding.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 50:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 12**

When will the updated asset condition assessment for wood poles be completed?

RESPONSE:

Please see Toronto Hydro's response to interrogatory U-AMPCO-114, part (c).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 51:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 14**

With respect to transformer replacement please break out the unit costs between Padmount and Underground. Please explain why the unit costs increased significantly in 2018 relative to 2016 and 2017. What is the projected unit cost for this asset category in 2019 and 2020?

RESPONSE:

The unit costs in the referenced table are derived from Toronto Hydro's financial reporting system, which tracks fully loaded capital costs by major asset type. The system does not distinguish between padmount and submersible (or other types of underground) transformers. As a result, Toronto Hydro cannot break out the unit costs between these two asset types.

Toronto Hydro cautions against using year-over-year unit cost results to draw conclusions about cost trends. There are many practical considerations that can and do drive significantly different unit costs from project to project. Broadly speaking, these include the type of work (e.g. pole replacement in Overhead Circuit Renewal vs. Box Construction Conversion; padmount vs. submersible transformer replacements), field conditions (e.g. vegetation density; utility congestion), design complexity, execution challenges (e.g. traffic density), and various external factors (e.g. work restrictions; third-party coordination). The variability of these drivers will cause significant volatility in unit costs from one year to the next. For this reason, Toronto Hydro's evidence emphasizes multi-year weighted averages for unit costs as opposed to single year values.

For a discussion on Underground Transformer unit cost results specifically, please see Toronto Hydro's response to U-EP-67, part (a).

The weighted three-year average unit costs used in the UMS Unit Cost Study, and updated in the table referenced by this interrogatory, were specifically designed to support comparative analysis of historical replacement costs for major asset classes relative to other utilities. Toronto Hydro has not developed a detailed unit cost forecasting methodology for these broad asset classes. A simplistic approach to forecasting would be to apply an inflationary assumption (e.g. 2 percent per annum) to the most recent (i.e. 2016-2018) three-year weighted (escalated) average unit cost. This approach for Underground Transformer Replacement would result in unit costs of $23,550 and $24,021 in 2019 and 2020 respectively. However, this approach does not account for the aforementioned volatility in year-over-year costs and gives no consideration to how future cost drivers may vary from past experience.

The utility's capital expenditure forecasts for asset replacement programs in the 2020-2024 Distribution System Plan have been estimated on a program-specific basis, using approaches that are most appropriate to each particular program. Examples of approaches include the use of asset-based unit costs (e.g. cost per pole) and programmatic unit costs (e.g. total Rear Lot Conversion project costs per customer). These detailed forecasts give due consideration to the specific nature of the work within these programs (e.g. box construction conversion vs. more typical overhead circuit renewal) and various factors that may cause future costs to vary from historical experience (e.g. differences in project complexity).

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 52:

Reference(s): Exhibit U, Tab 2, Schedule 1, p. 9

THESL has estimated the impact of the OEB's revised Customer Service Rules to be an increase of $1.6 million in 2020. Please provide a detailed explanation as to how that amount was calculated. What is THESL's materiality threshold? How does this impact the calculation of the custom capital factor in the 2021 and 2024 rate years?

RESPONSE:

Please refer to Toronto Hydro response to interrogatory U-Staff-169 for details on the calculation of the $1.6 million impact. The OEB materiality threshold for Toronto Hydro is $1.0 million of Revenue Requirement.

The adjustment to working capital will have an impact at the second or third decimal place in the calculation of the custom capital factor, or "C-factor", through the rate base component of the calculation. Please see Exhibit 1B, Tab 4, Schedule 1, section 3.3 for the calculation of Toronto Hydro's "C-factor".

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 53:

Reference(s): Exhibit U, Tab 2, Schedule 2, p. 17

During the 2015-2019 period THESL expects to spend 32 % less on System Service than its initial DSP forecast. Please provide a detailed schedule for the period 2015-2024 setting out all of the categories in the System Service category.

RESPONSE:

Please see the following table. The planned level of System Service investment in the 2020-2024 period is within one percent of the amount invested in the 2015-2019 period.

Table 1: Capital Expenditures by Program: System Service ($ Millions)

Program	Actual				Bridge					
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Energy Storage Systems	-	-	-	0.1	7.9	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4
Overhead Momentary Reduction	0.0	-	-	-	0.3	-	-	-	-	-
Stations Expansion	23.0	34.5	59.4	21.0	29.1	19.5	40.0	49.3	12.5	15.2
System Enhancements	7.1	17.2	12.2	9.4	4.0	6.2	6.2	5.6	4.8	4.9
Handwell Upgrades	4.7	0.8	0.8	0.0	-	-	-	-	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.4	-	-	-	-	-	-
Design Enhancement	0.0	0.6	(0.0)	0.0	0.2	-	-	-	-	-
System Service Total	**37.9**	**53.3**	**72.4**	**31.0**	**41.5**	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**

Note 1: Rounding differences exist.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 54:

Reference(s): Exhibit U, Tab 3, Schedule 2, p. 2

Please explain, in detail, how the $3 million reduction in Specific Service Charges was derived. Please include all assumptions.

RESPONSE:

Please refer to Toronto Hydro's response to part a) of interrogatory U-Staff-178.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 55:

Reference(s): **Exhibit U, Tab 6, Schedule 1**

THESL has identified a number of changes to the 2019 and 2020 bridge and test year forecasts (e.g. Other Revenues, OM&A, etc.) where the changes to the revenue requirement are relatively small. The evidence states, "In the interest of efficiency Toronto Hydro has decided to not flow through these changes through the revenue requirement work form or the cost allocation models." Is the complete list of these changes found in Exhibit U/T6? If not, please provide a complete list.

RESPONSE:

The changes referenced by this interrogatory are summarized in three separate Tabs in Exhibit U. For ease of reference, Toronto Hydro has compiled all of these changes into the list provided below. The estimated effects of these changes on revenue requirement are found at the reference provided for this interrogatory (i.e. Exhibit U, Tab 6, Schedule 1).

The tables and text that follow have been copied verbatim from Exhibit U.

OM&A changes (Exhibit U, Tab 4A, Schedule 1, Page 1):

Table 1: Identified Changes in OM&A for 2019 Bridge and 2020 Test Years

	Original Application		Identified Changes		Updated Figures	
OM&A Programs ($Millions)	**2019**	**2020**	**2019**	**2020**	**2019**	**2020**
Customer Driven Work	9.6	9.6	1.0	1.0	10.6	10.6
Asset and Program Management	15.3	13.1	0.0	0.8	15.3	13.9
Charitable Donations and LEAP	0.8	0.9	0.2	0.2	1.0	1.0
Common Cost and Adjustments	(1.3)	0.8	(1.4)	(1.5)	(2.7)	(0.7)
Subtotal	**24.4**	**24.4**	**(0.2)**	**0.5**	**24.2**	**24.8**
Adjusted Total OM&A	**268.2**	**277.5**	**(0.2)**	**0.5**	**267.9**	**278.0**

- In Common Cost and Adjustments, Toronto Hydro identified a reduction in post-employment benefits of $1.4 million in 2019 and $1.5 million in 2020 as a result of the most recent actuarial valuation (Exhibit U, Tab 4A, Schedule 3, Appendix C).

- In the Customer-Driven Work program, Toronto Hydro expects an increase of $1.0 million in 2019 and 2020 due to a higher demand for Toronto Hydro to facilitate safe entry into customer-owned vaults.

- The $0.8 million change to Asset Program Management in the 2020 test year relates to Local Demand Response costs that were inadvertently omitted from the original OM&A budget in Exhibit 4A.

- Similarly, the $0.2 million in LEAP costs relates to an omission in the original evidence.

Revenue Offset changes (Exhibit U, Tab 3, Schedule 2, Page 2):

In 2019, Revenue Offsets are expected to be approximately $2.1 million higher than the original forecast as follows:

- Specific Service Charges are expected to decrease by $1.5 million as a result of the removal of the Collection of Account and Install/Remove Load Control Devices charges as of July 1 in accordance with the OEB rate order dated March 14, 2019, made under Phase 1 of the Customer Service Rules review (EB-2017-0183).

- Other Income and Deductions is expected to increase by $3.6 million due to lower merchandising and jobbing costs of $2 million as a result of capitalization of major assets related to accident claims, and a $1.6 million gain on disposition of a property which is expected to be sold in the second or third quarter of this year.

The 2019 changes to specific service charges revenues and merchandising and jobbing cost changes are expected to affect the 2020 forecast, as summarized in Table 2 below.

Table 2: Identified Changes in Other Revenues for 2020 Test Years ($ Millions)

	2020 Test Year Original Forecast	Identified Changes	Revised 2020 Test Year
Specific Service Charges	6.6	(3.0)	3.6
Late Payment Charges	3.8	-	3.8
Other Operating Revenues	12.0	-	12.0
Other Income or Deductions	25.4	2.0	27.4
Total	47.7	(1.0)	46.8

Working Capital Allowance (Exhibit U, Tab 2, Schedule 1, Page 8):

- The response to interrogatory 2A-Staff-53 included an estimate of the Working Capital Allowance reflecting the Cost of Power as calculated using the OEB's Appendix 2-Z. This resulted in a Working Capital Allowance of $202.9 million, compared with the pre-filed value of $235.2 million. The lower Working Capital Allowance would reduce 2020 revenue requirement by approximately $2.2 million.

- Toronto Hydro notes that the Ontario Energy Board’s revised Customer Service Rules – specifically the extension of the bill payment dates – are expected to have an impact on the collection lag component of the Lead/Lag study. Toronto Hydro estimates the impact of these changes on 2020 revenue requirement to be an increase of $1.6 million.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 64:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 4, 2.10 System Reliability: SAIDI/SAIFI**

Preamble:

"Toronto Hydro achieved improvements in both SAIDI and SAIFI in 2018. SAIDI was measured at 0.81, which is a reduction from the 0.91 in 2017 and 2016. SAIFI in 2018 reduced to 1.14 versus the 1.18 in 2017 and 1.28 in 2016."

a) At a high level please provide a short narrative with the reasons that SAIDI and SAIFI (CAIDI) have improved over 2015-2018 period, including system renewal investment.

b) Please comment if TH is an average performer relative to its Ontario peer group, and if system reliability will continue to improve, given continuing investment over the 2020-2024 CIR Plan Period?

c) Please confirm that TH provided 2020-2024 reliability projections/outlook to PSE and PEG for their Econometric models.

d) Please provide a copy of this projection/outlook.

e) Please comment if the reliability improvement in 2018 is material relative to the projection/outlook provided to PSE and PEG.

RESPONSE:

a) As illustrated in Exhibit U, Tab 1B, Schedule 1, pages 23 and 24 (in Figures 16 and 17), reliability performance has improved over the 2015-2018 period. For example, after excluding major event days (i.e. MEDs) and loss of supply (i.e. LOS), SAIFI and SAIDI have improved by an average of approximately 4 percent and 6 percent respectively each year. Although some of the improvement can be attributed to reductions in contributions from cause codes such as Adverse Environment, Human Element, and Scheduled Outages, the majority of the improvement is attributed to reductions in interruptions caused by Defective Equipment.

   The reductions in Defective Equipment interruptions have been achieved predominantly through investment in System Renewal. Between 2015 and 2018, Toronto Hydro invested $1,066 million in this category of capital expenditures. Although $204 million of this was for Reactive Capital, the remainder was directed to planned investments that addressed aging, deteriorated, and obsolete assets that posed elevated reliability (and other) risks. (Please see Exhibit U, Tab 2, Schedule 2, at pages 9 and 16 for Tables 9 and 15 for expenditure details between 2015 and 2018.)

   With respect to 2018, please note that although SAIFI and SAIDI results bettered 2015-2017 results, they benefited from performances in some areas that are considered to be anomalies. For example, SAIFI benefited from its best performance in the past 15 years for the cause codes of Lightning and Scheduled Outages. Within the Defective Equipment cause code, contributions from assets such as non-direct buried cables, overhead insulators, and poles were lower than expected and are also considered to be anomalies.

b) The following two graphs compare the SAIFI and SAIDI performance (excluding Loss of Supply and Major Event Days) of Toronto Hydro to the other Ontario utilities using OEB RRR data for the most recently availably year, 2017. The charts highlight Toronto Hydro's performance in orange, other utilities that serve the Greater Toronto Area (GTA) in green, and the remaining utilities in grey. Toronto Hydro's reliability performance is worse than average for SAIFI (i.e. third quartile) and better than average for SAIDI (i.e. second quartile) when compared to all other Ontario utilities.

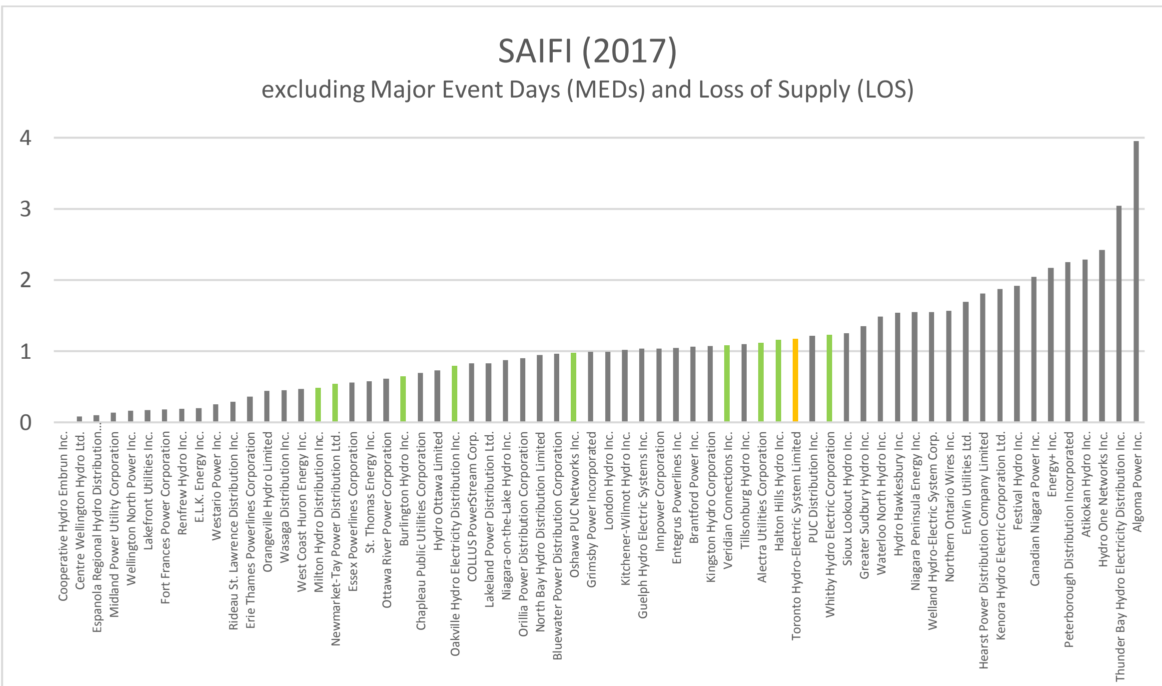


Figure 1: 2017 SAIFI (excluding MEDs and LoS)

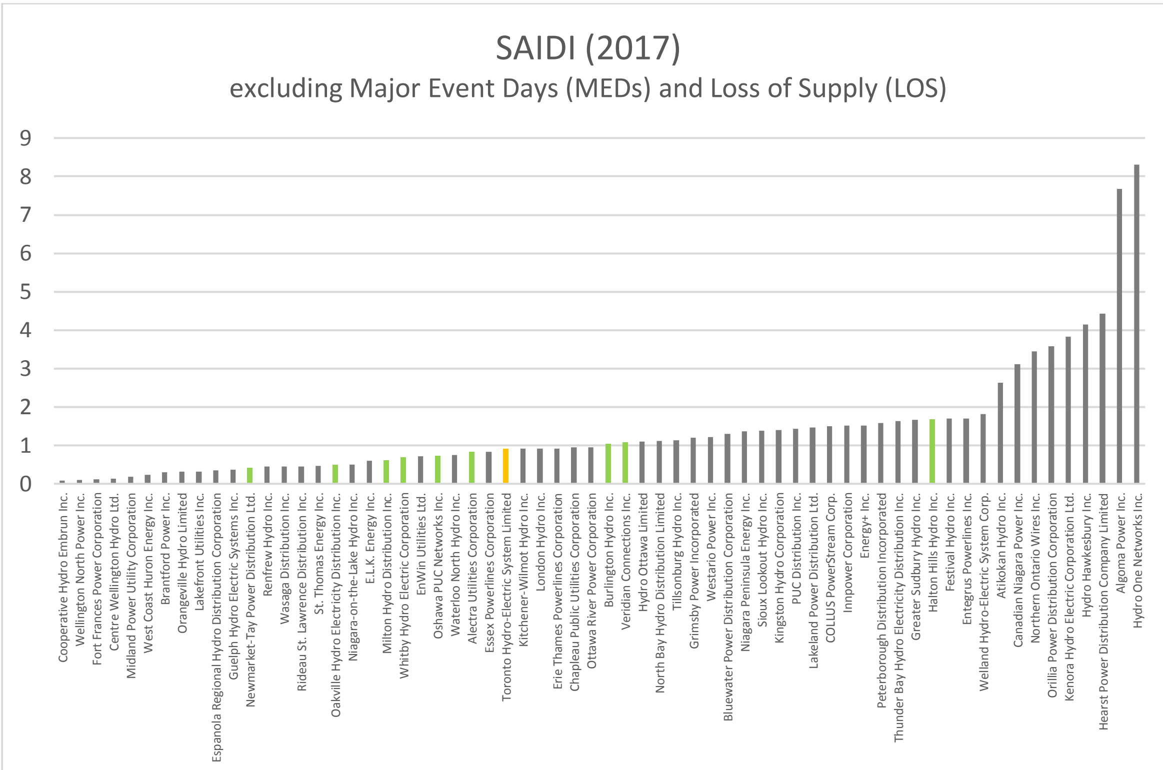


Figure 2: 2017 SAIDI (excluding MEDs and LoS)

These findings are directionally similar to the findings in PSE's reliability benchmarking study, which used an econometric approach to compare Toronto Hydro to a broader set of U.S. utilities. That study found that Toronto Hydro is worse than its predicted benchmark on SAIFI performance and better than its benchmark on SAIDI performance.

The results above do not speak to the customer's perspective on Toronto Hydro's reliability performance and whether that performance aligns with customer priorities. As explained in Exhibit 2B, Section E2.3.1, feedback received during the first phase of customer engagement indicated that the average customer was satisfied with current reliability performance. Customer priorities were to keep distribution price increases to what is necessary to maintain long-term performance for customers experiencing average or better reliability service, and improve service levels for customers experiencing below average service. In response to this feedback, Toronto Hydro designed a plan that would achieve these objectives.

As illustrated in Toronto Hydro's response to U-SEC-105, Toronto Hydro does not expect continued improvement in SAIDI and SAIFI results through the 2020-2024 period. As detailed throughout the DSP, the utility has relied on various indicators of future asset performance (e.g. asset health) and other indicators of system need (e.g. weather and climate analyses) to develop an expenditure plan that is paced to prevent asset failure risk from increasing over the period (e.g. by seeking to maintain the number of assets in HI4 and HI5 condition). Toronto Hydro is generally not planning to invest at a pace that will reduce asset failure risk from current levels, with a few exceptions for areas where risk accumulation has reached unacceptably high levels (e.g. Stations Renewal). In addition, the utility used its Reliability Projection methodology – which compiles asset demographics data, historical reliability performance, and planned program investments – to guide the development of the proposed plan and ultimately ensure that the proposed investment program would be of the right pace and mix to sustain system reliability. The results of this analysis are shown at Exhibit 2B, Section E2, Figures 8 and 9.

Toronto Hydro's proposed increase in total capital expenditures relative to the 2015-2019 period is necessary to deliver not only on its proposed reliability outcomes, but also to manage a number of other critical needs and objectives that drive material investment requirements. Some examples are provided below.

System Renewal

Although System Renewal as a proportion of the overall Distribution System Plan is remaining consistent at approximately 57 percent in 2020-2024 (relative to 2015-2019), the mixture of planned work is shifting to address significant needs on parts of the distribution system that contribute less to system average reliability, and more to critical drivers such as safety, resiliency and environmental impacts. For example:

- Toronto Hydro is planning to invest $122 million in the new Underground System Renewal – Downtown program, which replaces obsolete lead and asbestos cables that pose environmental risks. The program also manages a growing population of deteriorating civil assets such as cable chambers, which present safety risks. (Please see Exhibit 2B, Section E6.3, Table 1.)

- Toronto Hydro is planning an increase of $56 million from 2015-2019 in Stations Renewal to address deteriorating assets that generally have a lower probability of causing an outage, but that can lead to significant consequences (e.g. widespread customer outages; extended weakening of system contingency capabilities) if a failure is to occur. (Please see Exhibit 2B, Section E6.6, Table 1.)

- Based in part on historical trends, the plan includes projected increases in Reactive Capital, which often replaces equipment after it has failed and has contributed to unreliability, instead of prior to failure. (Please see Exhibit 2B, Section E6.7, Table 1.)

- The plan includes an increased proportion of spot replacements, particularly for transformers containing, or at-risk of containing PCBs, in both the Overhead System Renewal and Underground System Renewal (Horseshoe)

Program. Spot replacements of transformers mitigate less reliability risk than area rebuilds, which target clusters of deteriorated assets in an area. (Please see Exhibit 2B, Section 6.5, page 20, lines 1 to 3 and Section 6.2, page 32, lines 26 to 30.)

<u>System Service</u>

System Service investments that have the potential to contribute to improvements in reliability have either been reduced in 2020-2024 (e.g. System Enhancements, discussed in Exhibit 2B, Section E7.1, Table 1) or in the case of Network Condition Monitoring and Control (i.e. Exhibit 2B, Section 7.3), are being directed to the Network System, which on a day-to-day basis is highly reliable (given its inherent design), to address safety and resiliency needs. (Please see Exhibit 2B, Section C2, page 11, for details related to Toronto Hydro's Network Units Modernization objectives.)

<u>System Access</u>

Toronto Hydro is forecasting an increase in System Access investments in 2020-2024 to address demand and compliance-based projects that are largely unrelated to system average reliability. For example, the utility anticipates greater investments in Customer Connections, Externally Initiated Plant Relocations, and Metering.

c) Toronto Hydro confirms that it provided 2020-2024 reliability projections for SAIFI and SAIDI to PSE. These same projections were provided to PEG via the request for PSE's working papers. These projections used a momentary interruption definition of five minutes or less (as opposed to Ontario's one minute or less) for comparison with U.S. utilities.

d) Please refer to Toronto Hydro's response to Technical Conference undertaking JTC2.10 for projections of SAIFI and SAIDI provided to PSE.

RESPONSE (PREPARED BY PSE):

e) Toronto Hydro's 2018 reliability results would improve the model result for SAIFI by an estimated 3 percent and would worsen the CAIDI results by about 2 percent. PSE does not consider this to be a material change within the context of our findings.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 65:

Reference(s): Exhibit U, Tab 1B, Schedule 1, Page 2, Table 1: Toronto Hydro EDS Performance - 2014-2018
Exhibit U, Tab 1B, Schedule 1, Page 38, 2018 Corporate Scorecard Update
Responses to Interrogatories 1B-SEC-8 and 4A-AMPCO-96

a) Please provide the Scorecard 2018 Cost Control Data for the following categories:
   i) Efficiency,
   ii) Total cost/customer,
   iii) Total cost/km of line.

b) Please discuss the trend and cross reference to response to U-EP-71 Admin Costs/Customer

RESPONSE:

a) The 2018 results for the identified measures are determined by PEG on behalf of the OEB. Toronto Hydro expects the 2018 results for all utilities to be issued in August 2019 by the OEB.

b) Please see the response to part (a).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 66:

Reference(s): Exhibit U, Tab 1B, Schedule 1, Pages 16 and 17; Figure 13
Response to Interrogatory 2B-EP-32

<u>Preamble:</u>

"The five-year annual frequency value for the period 2014 to 2018 is 2.64 compared to the corresponding value of 2.74 reported in the utility's last Rate Application (for the period 2009 to 2013). For 2018, MAIFI was 2.78. This result represents an increase from the prior years, which is due to a number of drivers including weather."

a) Please update for the last 5 years 2014-2018 Table 1 and Figure 1 provided in response to 2B-EP-32.

b) Why is the cause for approximately 61% of momentary interruptions unknown? How does TH distinguish momentary interruptions from System interruptions?

c) Please compare MAIFI to SAIDI and SAIFI in terms of annual customer interruptions.

d) Please discuss whether momentary interruption events are more localized compared to system interruption events and is there a connection or correlation with lower voltage feeders and/or with defective equipment more or less than with system events?

e) Please provide OEB peer group, CEA and FERC data on average utility MAIFI and comment on how TH relates to these data.

f) Why is TH MAIFI getting worse despite the large infrastructure investment? Explain the reasons in detail with reference to response to interrogatory 2B-EP-32.

g) What is TH doing to stabilize and improve MAIFI over the 2020-2024 CIR period including how much is TH investing specifically to reduce MAIFI events?

RESPONSE:

a) Please see the updated table and figure below.

Table 1: MAIFI Cause Codes

	2014	2015	2016	2017	2018	5-Year Avg.
Adverse Environment	0.01	0.06	0.01	0.01	0.00	0.02
Adverse Weather	0.19	0.23	0.19	0.15	0.20	0.19
Defective Equipment	0.49	0.37	0.36	0.27	0.31	0.36
Foreign Interference	0.26	0.21	0.24	0.20	0.22	0.23
Human Element	0.01	0.01	0.01	0.01	0.01	0.01
Lightning	0.05	0.02	0.04	0.04	0.02	0.04
Loss of Supply	0.00	0.04	0.01	0.10	0.07	0.05
Tree Contacts	0.03	0.05	0.02	0.04	0.06	0.04
Unknown	1.50	1.74	1.74	1.68	1.88	1.71
TOTAL	2.55	2.72	2.64	2.52	2.78	2.64

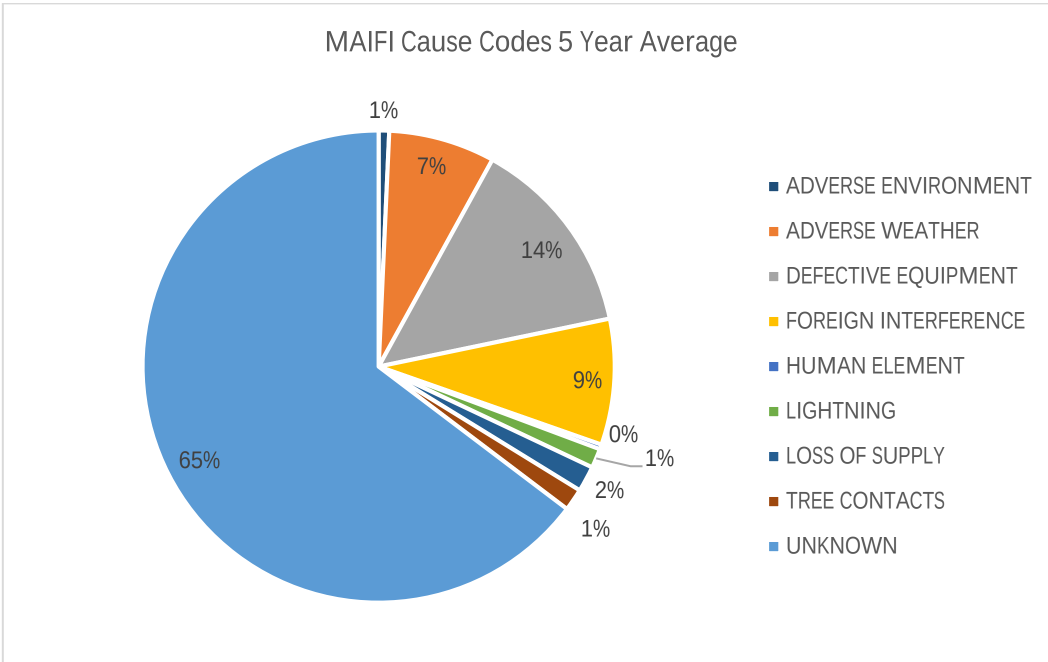


Figure 1: MAIFI Cause Code Breakdown 5-Year Average

b) Toronto Hydro follows the OEB Electricity Reporting and Record Keeping Requirements. Outages less than one minute in duration are categorized as momentary interruptions. When a breaker trips and recloses without any persistent or apparent cause, the outage would be categorized as an Unknown.

Please see Toronto Hydro's response to Interrogatory U-VECC-62 for additional discussion regarding Toronto Hydro's MAIFI results and how the utility is managing MAIFI performance.

c) MAIFI cannot be compared to SAIDI and SAIFI as these measure different aspects of reliability. SAIDI measures the duration of interruptions experienced by customers, while both MAIFI and SAIFI measure the frequency of outages experienced by customers. MAIFI measures interruptions that are less than a minute, and SAIFI measures interruptions that are a minute or longer. Added together, these two measures would cover all outages that customers experience. However, as described in Toronto Hydro's response to Interrogatory 1B-Staff-14, the utility's ability to measure MAIFI accurately is limited by manual processes and incomplete SCADA coverage. This precludes a meaningful comparative analysis of MAIFI and SAIFI results.

d) For the purpose of this response, Toronto Hydro has taken "System Events" to mean sustained interruptions (i.e. interruptions lasting one minute or longer).

Momentary interruption events are not necessarily more localized compared to sustained interruption events (system interruption events). Generally, momentary interruption events result from the operation of a circuit breaker at a station. Sustained interruption events could result following the operation of a circuit breaker at a station, or following the operation of a protective device (e.g. a switch or fuse) on a feeder emanating from a station. The operation of a station breaker generally interrupts a greater number of customers than the operation of a protective device on the same feeder.

Due to the current limitations in tracking MAIFI, mentioned in response to part (c), Toronto Hydro does not have the data necessary to accurately assess whether there is a correlation between feeder voltage and the frequency of momentary interruptions.

As shown in response to part (a), Defective Equipment is the second largest cause of Momentary Interruptions behind "Unknown". Toronto Hydro would expect a positive correlation between the amount of defective equipment and the frequency of all interruptions caused by defective equipment. Toronto Hydro would also expect defective equipment outages to have a larger effect on sustained interruptions than momentary interruptions. This is because a piece of failed equipment will most often require crews to make a repair or replacement.

e) The OEB does not require utilities to track MAIFI. As a result, there is limited data availability within the OEB peer groups and the CEA. Toronto Hydro is also unable to find a compiled repository of MAIFI results from FERC for comparison.

f) As can be seen in the table in response to part (a), Defective Equipment has declined slightly as driver of MAIFI since 2013. However, Unknown causes have increased over this period and are by far the largest contributor to momentary interruptions. Please refer to Toronto Hydro's response to interrogatory U-VECC-62 for details on Toronto Hydro's efforts to reduce momentary interruptions of unknown cause.

g) Please refer to Toronto Hydro's response to Interrogatory 2B-EP-33, part (e), and U-VECC-62 for the utility's initiatives for managing MAIFI.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 67:

Reference(s): Exhibit U, Tab 1B, Schedule 1, pp. 13 and 14, Table 2

Preamble:

"In its response to undertaking JTC4.25.4, Toronto Hydro committed to provide 2018 data for the unit costs reported into the UMS Unit Cost Study, which is inclusive of the aforementioned unit categories. (See Table 2 below for the 2018 unit costs and an updated three-year average.) While there is significant volatility in the year over-year results, the data nonetheless demonstrates stable or improving unit cost performance over the last three years."

a) Please reconcile this Statement with unit costs for:
   i) wooden pole replacement (minimal reduction),
   ii) 2017 tree trimming (increase in 2018),
   iii) underground (submersible and vault) transformer replacement (increase in 2018).

b) Please provide the drivers for the changes.

c) Please provide a chart that shows the data and trend lines for these assets for the 2014-2018 CIR period (if 2014/15 not available then the last 3 years).

RESPONSE:

a) Toronto Hydro maintains that the unit cost data demonstrates stable or improving unit cost performance over the last three years. Evidence of this is found in the three-year rolling averages illustrated in the charts within parts (i), (ii), and (iii) below. Please also see additional notes, and updated unit cost figures in Toronto Hydro's response to interrogatory U-AMPCO-116.

Three-year rolling averages have been selected to smooth out the year-over-year fluctuations that are likely to occur. (Please see Exhibit 2B, Section C2, page 22.) To ensure the most appropriate comparisons, the three year-rolling averages have been escalated to 2018 dollars using the OEB's escalation rates: 1.6 percent (2014), 1.6 percent (2015), 2.1 percent (2016), and 1.9 percent (2017).

i) For Wooden Pole Replacement, unit costs have been improving. There has been a 4 percent reduction between the escalated rolling averages of 2014-2016 and 2016-2018.

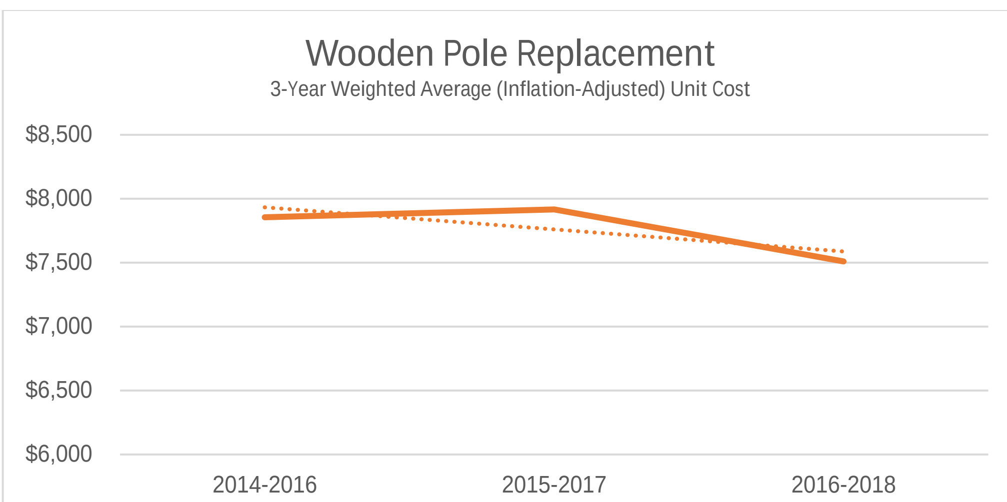


Figure 1: Escalated Rolling Averages Unit Costs for Wooden Pole Replacement

ii) For Vegetation Management, unit costs have remained stable. There has been a 2 percent reduction between the escalated rolling averages of 2014-2016 and 2016-2018.

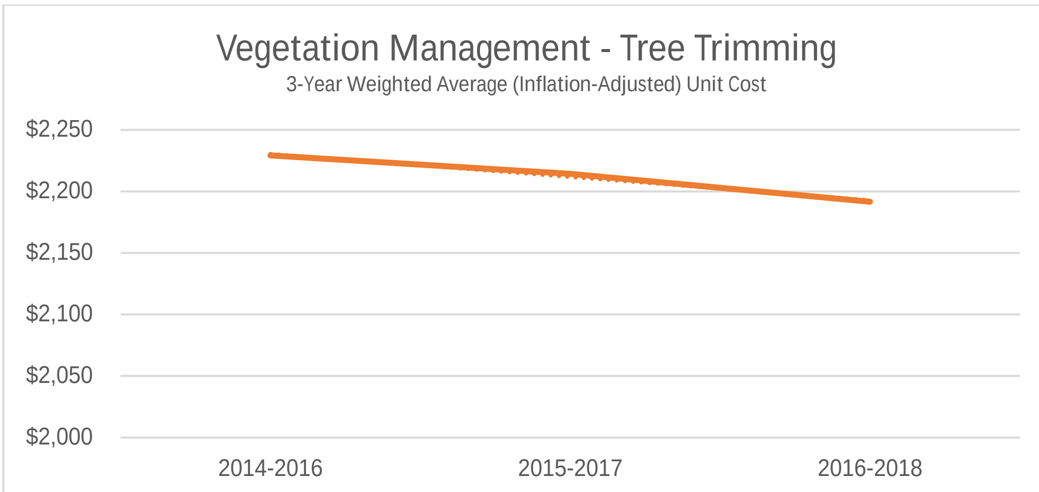


Figure 2: Escalated Rolling Average Unit Costs for Vegetation Management – Tree Trimming

iii) For Underground Transformer Replacement, unit costs have remained stable. There has been a 2 percent increase between the escalated rolling averages of 2014-2016 and 2016-2018.

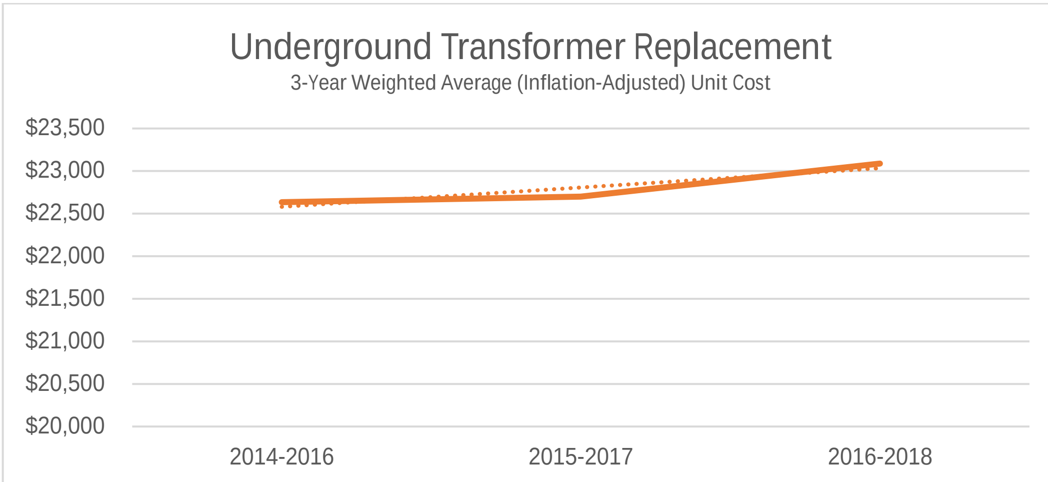
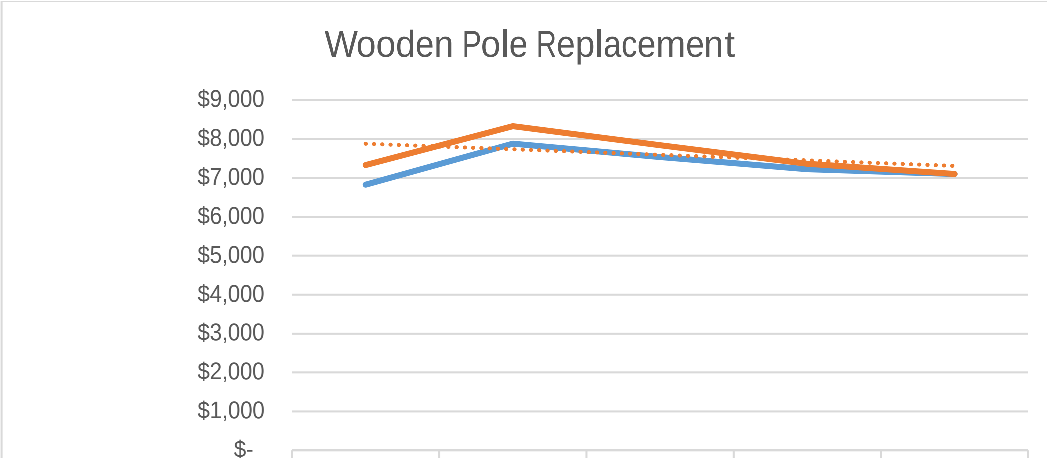


Figure 3: Escalated Rolling Average Unit Costs for Underground Transformer Replacement.

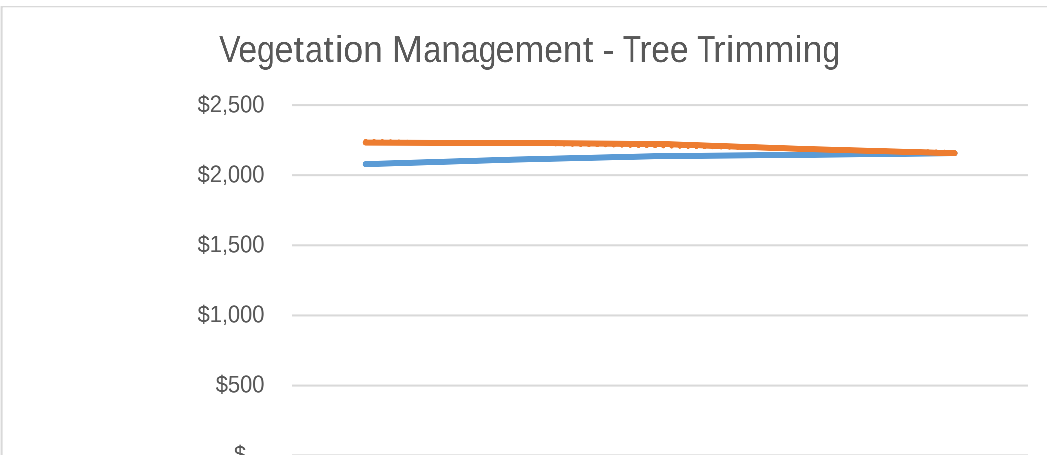
b) With respect to unit cost changes from one year to the next, Toronto Hydro did not experience changes for Wooden Pole Replacement and Vegetation Management in 2018 relative to the natural fluctuations that occurred over 2014 to 2017. With respect to Underground Transformer Replacement, 2018 unit costs were approximately 7 percent higher (on an inflation-adjusted basis) than the previous high experienced in 2016. This is attributed to differences in project specific factors associated with work that was undertaken in 2018. As with many of Toronto Hydro's major assets, such differences can cause significant fluctuations (e.g. 10 percent to 30 percent or greater) in unit costs from one year to the next.

c) Please see Figures 4-6 below.



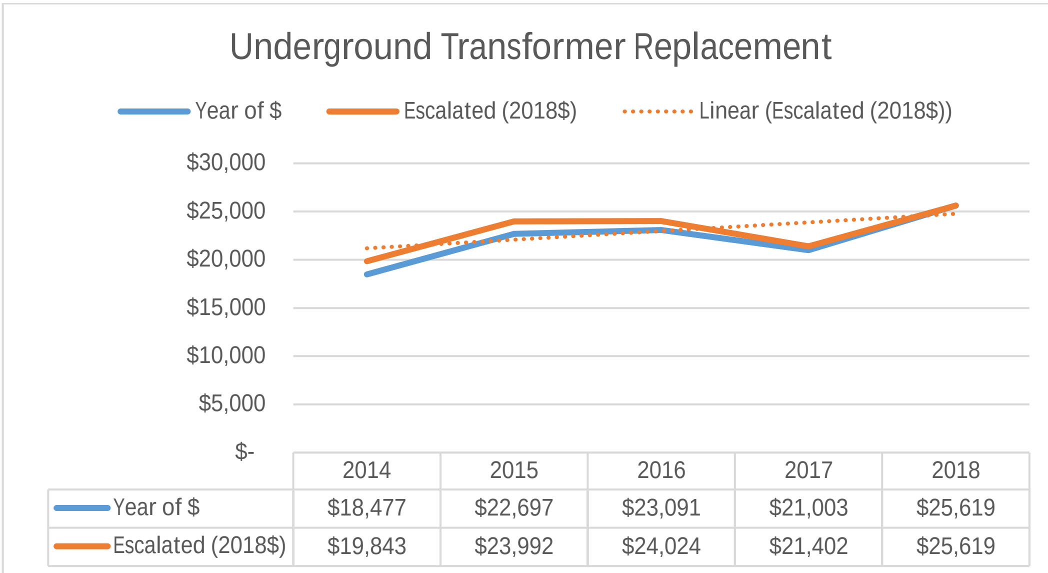
	2014	2015	2016	2017	2018
Year of $	$6,826	$7,880	$7,538	$7,225	$7,101
Escalated (2018$)	$7,331	$8,329	$7,843	$7,362	$7,101

Figure 4: 2014-2018 Unit Costs for Wooden Pole Replacement



	2014	2015	2016	2017	2018
Year of $	$2,080	$2,111	$2,137	$2,147	$2,158
Escalated (2018$)	$2,234	$2,231	$2,223	$2,188	$2,158

Figure 5: 2014-2018 Unit Costs for Vegetation Management – Tree Trimming



	2014	2015	2016	2017	2018
Year of $	$18,477	$22,697	$23,091	$21,003	$25,619
Escalated (2018$)	$19,843	$23,992	$24,024	$21,402	$25,619

Figure 6: 2014-2018 Unit Costs for Underground Transformer Replacement

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 68:

Reference(s): **Exhibit U, Tab 1C, Schedule 5, pp. 63 and 64 Performance-based Incentive Compensation**

Preamble:

"In 2018, the Corporation exceeded all of its corporate targets represented by its KPIs. The NEOs exceeded the majority of their divisional and individual performance targets for 2018. Each of the corporate, divisional and individual performance targets were reasonably difficult to attain and served to encourage success in the NEOs performance and in the Corporation's overall results."

a) Please provide the amounts of incentive pay the NEOs received in 2018. Position this for each as a percentage of their Total Compensation and Salary.

b) Please provide the Corporate KPIs that will govern incentive pay in the 2020 Test Year and compare to 2018. Discuss any differences

c) Please provide the 2020 targets and weightings and note any differences to 2018.

RESPONSE:

a) Please refer to Appendix A of this response for incentive pay provided to NEOs in 2018. Toronto Hydro's executive compensation is aligned with its comparators in terms of base salary and variable performance pay as assessed by Mercer (Canada)

Limited in its senior executive compensation review. Please refer to 1B-SEC-3, Appendix D for further information.

b) This information is not available. The Corporate Scorecard (inclusive of metrics, targets and weightings) for a given year is approved by the Board of Directors in the fourth quarter of the preceding year.

c) Please refer to part (b) of this response.

Annual Information Form - Summary Compensation Table

NEO Name and Principal Position	Salary	Non-Equity Incentive Plan Compensation	All Other Compensation	Total Compensation	Incentive Pay as Percentage of Total Compensation	Incentive Pay as Percentage of Salary
Anthony Haines President and Chief Executive Officer, Toronto Hydro Corporation	583,999	570,068	16,053	1,170,120	49%	98%
Sean Bovingdon Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	262,632	153,273	1,727	417,632	37%	58%
Aida Cipolla Executive Vice-President and Chief Financial Officer Toronto Hydro Corporation	215,668	111,400	1,560	328,628	34%	52%
Dino Priore Executive Vice-President and Chief Engineering and Construction Officer Toronto Hydro-Electric System Limited	377,561	224,808	4,580	606,949	37%	60%
Ben La Pianta Executive Vice-President and Chief Customer Care and Electric Operations Officer, Toronto Hydro-Electric System Limited	346,704	207,482	9,133	563,319	37%	60%
Amanda Klein Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer Toronto Hydro-Electric System Limited	283,000	169,800	2,863	455,663	37%	60%

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 69:

Reference(s): Exhibit U, Tab 2, Schedule 1, p. 1, Table 1 and p. 3

Preamble:

"Rate base is forecasted to increase by $298.9 million from 2018 to 2019. The increase in average PP&E NBV of $243.8 million is primarily due to assets coming into service. WCA is expected to increase by $55.1 million, primarily due to projected increases in commodity costs."

a) Please explain the increase in WCA for 2019 Bridge year and the forecasted decrease for 2020.

b) Please provide details of the drivers/amounts at a high level- COP etc.

RESPONSE:

a) The increase in 2019 forecasted WCA over 2018 actual is due to the projected increase in commodity costs. Toronto Hydro based its 2019 forecast commodity rates on those found in the OEB's April 2018 Regulated Price Plan Supply Cost Report.

The decrease in 2020 is primarily due to the reduction in the WCA rate (from 8.02 percent to 6.42 percent) resulting from the updated the lead/lag study.[1]

b) Please see Table 1 for the drivers contributing to the annual changes.

Table 1: Working Capital Allowance Change ($ Millions)

	2018 - 2019	2019 - 2020
Prior Period WCA	232.1	287.2
COP Calculation	55.1	5.7
Change in OM&A	-	0.7
Change in WCA Rate	-	- 58.4
Current Period WCA	287.2	235.2

[1] EB-2018-0165, Exhibit 2A, Tab 3, Schedule 3, Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business by Navigant Consulting Ltd.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 70:

Reference(s): Exhibit U, Tab 3, Schedule 1, Page 2, Appendices B, C and D
Updated Responses to Interrogatories 3-VECC-25 and 3-VECC-26

Preamble:

"Toronto Hydro notes the very recent Provincial directives on conservation programs in the province. However, at time of preparation of the load forecast for the update, the potential impacts are unknown, and therefore Toronto Hydro has included the latest forecast for CDM savings through the forecast period.

a) For the Residential and CSMUR Sectors please provide a summary table with the original CDM forecast and updated forecast 2018-2024 including the load forecast for these sectors.

b) How will uploading CDM to IESO affect TH in respect of the following:
   i) recovery of CDM costs,
   ii) attribution,
   iii) load forecast?

RESPONSE:

a) Please see Table 1 and Table 2.

Table 1: Summary table with the original CDM forecast and updated forecast 2018-2024 for Residential and CSMUR Sectors

	Original CDM Forecast MWh		Updated CDM Forecast MWh	
	RES	CSMUR	RES	CSMUR
2018	638,045	10,300	753,504	13,251
2019	659,746	16,846	787,453	15,434
2020	670,817	23,205	801,974	17,218
2021	680,526	29,504	814,023	18,888
2022	690,234	35,804	826,072	20,558
2023	699,943	42,103	838,121	22,228
2024	709,651	48,403	850,169	23,898

Table 2: Summary Table with original distribution load forecast and updated forecast 2018-2024 for Residential and CSMUR Sectors

	Original Distribution Load Forecast MWh		Updated Distribution Load Forecast MWh	
	RES	CSMUR	RES	CSMUR
2018	4,579,986	256,194	4,770,272	266,755
2019	4,532,015	263,913	4,543,879	278,115
2020	4,510,637	277,127	4,531,218	297,764
2021	4,458,696	286,904	4,488,480	314,676
2022	4,422,718	300,278	4,462,016	336,412
2023	4,386,740	313,818	4,435,553	352,415
2024	4,366,438	328,419	4,425,206	367,618

b)

i) In accordance with OEB requirements, there is accounting separation between the costs associated with CDM delivery and rate regulated distribution. As a result, ratepayers will not be affected by the provincial change to CDM delivery.

ii) The attribution of savings is no longer relevant as conservation targets are no longer assigned to individual LDCs nor does the IESO intend to track results at the LDC level.

iii) As noted above, the IESO will no longer be providing LDC level results. Further, if IESO CDM delivery is not tracked and reported at the LDC level, the impacts of provincially funded CDM on Toronto Hydro's load forecast will be more difficult to predict.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 71:

Reference(s): Exhibit U, Tab 4A, Schedule 1, OEB Appendix 2L

a) Please explain what is included in Admin Costs. (major accounts).

b) Please provide the amounts of indirect and direct Admin Costs and explain how these are treated and allocated e.g. expensed or capitalized.

c) The Referenced Table shows Admin costs per customer have increased by about $10 2015-2019 and will increase by a further $10 in 2020 for a total increase of about $20 per customer over 5 years. Please justify these material increases and provide details on the drivers.

d) Indicate what steps have been or will be taken to constrain these costs.

RESPONSE:

a) The Administrative Expenses ("Admin Expenses") row in OEB Appendix 2-L includes the following major groupings: Billing and Collecting, Community Relations, Administrative and General Expenses, Taxes Other Than Income Taxes, and Donations.

The OM&A programs that primarily contribute to these expenses are: Customer Care (Exhibit 4A, Tab 2, Schedule 14), Human Resources and Safety (Exhibit 4A, Tab 2, Schedule 15), Finance (Exhibit 4A, Tab 2, Schedule 16), Information Technology

(Exhibit 4A, Tab 2, Schedule 17), Legal and Regulatory (Exhibit 4A, Tab 2, Schedule 18), and Charitable Donations and LEAP (Exhibit 4A, Tab 2, Schedule 19).

b) For the purposes of rate design, Admin Expenses are treated as indirect costs. These costs form part of OM&A and are therefore expensed.

c) The Admin Expenses in the 2020 Test Year include $5.0 million related to monthly billing and $2.3 million related to the change in accounting treatment of OPEBs from cash to accrual. Over the 2015-2019 period, the costs associated with monthly billing and the difference between cash versus accrual method for recognition of OPEB costs were tracked in deferral and variance accounts and were not included in OM&A until the 2020 Test Year. When normalized for these changes, the 2020 Admin Expenses are $143.1 million, and the Admin per customer is $182.40. This represents an increase of $1.00, or 0.6 percent, from 2019 to 2020, and $10.80, or 1.2 percent annually, from 2015 to 2020.

d) As indicated in response to part (c), Toronto Hydro constrained its Admin Expenses costs from 2015 to 2020 to a 1.2 percent annual increase, while managing the various challenges and cost pressures which are summarized in the response to interrogatory 4A-AMPCO-68 and throughout the applicable program narratives. This increase is below the historical average rate of inflation of 2.2 percent in the City of Toronto.[1]

[1] Refer to Toronto Hydro's response to interrogatory 4A-AMPCO-71 for more information on this inflation figure.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 72:

Reference(s): Exhibit U, Tab 4A, Schedule 5, Appendix B, Updated JTC 3.22
Exhibit U, Tab 4A, Schedule 3, Appendix A, OEB Appendix 2-K

a) Please provide the following clarifications and explanations:
   i) Why has the head count for this group decreased in 2018 then increased by 100 in 2019?
   ii) Why have Salaries and Wages for this group increased by about $ 6 million 2015-2018, and then increased to about 15.5 million 2015-2019 with an increased headcount of 40 relative to 2015?
   iii) Why are Salaries and Wages increasing in 2020 by an additional $3.5 million, despite a reduced 2020 headcount?

b) Provide the total and average percentage increases in Total Compensation and explain why the increase in Total Compensation for this group of about $28 million for 2015-2020 is reasonable.

RESPONSE:

a) Toronto Hydro assumes Energy Probe's questions in part (a) of this interrogatory refer to the Non-Management (union and non-union) category in the Employee Cost table. All of the answers that follow are provided in the context of this employee category.

   i) Please refer to Toronto Hydro's response to interrogatory U-VECC-87, part (b).

ii) For the reasons detailed in part (b) of Toronto Hydro's response to interrogatory U-VECC-87, the increase in salary and wages from 2015 to 2018 was lower than expected because of delays in hiring various resources. The 2018 results affected the variance from 2018 to 2019.

iii) The additional $3.2 million from 2019 to 2020 represents a 2 percent growth in salary and wages for this period. The total increase in salary and wages from 2019 to 2020 is lower for this period due to the decrease in FTEs from 2019 to 2020.

b) From 2015 to 2020 the total compensation for the Non-Management group has increased by 38 percent, which represents a compounded annual growth rate of 6.7 percent; however, once the data has been normalized for the yearly growth of the average number of FTEs and yearly average changes to benefits, the average increase in compensation costs for the Non-Management group is 13.2 percent, which represents a compounded annual growth rate of 2.5 percent. When compared to market conditions for salaries and wages in this group, the rate of growth in this category is reasonable and aligned with Toronto Hydro's compensation strategy of maintaining market competitive salary and wages, as discussed in Exhibit 4A, Tab 4, Schedule 4.

Furthermore, part of the growth in compensation from 2015 to 2020 is driven by a modest FTE increase. The additional resources are needed to support the execution of large and complex capital projects, which are being carried out by both internal and external resources. They are also needed to provide enhanced supervision and program management, and to continue to execute the utility's workforce renewal and training and development plan.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 98:

Reference(s): Exhibit U, Tab 1B, Schedule 1, p.14, Table 2

With respect to Table 2:

a) Please confirm that under the 2018 column, it should read ‘Unit Costs (2018)’ and not ‘Unit Costs (2017)’.

b) Please provide the table in excel format.

RESPONSE:

a) Confirmed, the column under 2018 should read ‘Unit Costs (2018)’.

b) Please refer to the excel file provided in response to U-AMPCO-116, part (b), titled “U-AMPCO-116 App A”.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 99:

Reference(s): Exhibit U, Tab 1C, Schedule 5, p.62;
1B-SEC-8, Table 5

Similar to what is provided in the 2018 Toronto AIF, please provide the weightings for the 2019 corporate scorecard.

RESPONSE:

Please see Table 1 below.

Table 1: 2019 Corporate Scorecard with Weightings

<table>
<tr><th>Key Performance Indicator</th><th colspan="2">2019 Target</th><th>Weight (%)</th></tr>
<tr><td>New Services Connected on Time</td><td colspan="2">97.7%</td><td>5</td></tr>
<tr><td>Bill Accuracy</td><td colspan="2">99.0%</td><td>5</td></tr>
<tr><td>First Contact Resolution</td><td colspan="2">86%</td><td>5</td></tr>
<tr><td>Total Recordable Injury Frequency (TRIF)</td><td colspan="2">1.4</td><td>10</td></tr>
<tr><td>Employee Engagement</td><td colspan="2">6.5</td><td>5</td></tr>
<tr><td>SAIFI (# - Defective Equipment Only)</td><td colspan="2">0.52</td><td>10</td></tr>
<tr><td>SAIDI (Minutes - Defective Equipment Only)</td><td colspan="2">27.71</td><td>10</td></tr>
<tr><td rowspan="2">5-Year CIR Distribution System Plan Investment ($M)</td><td>Lower Target</td><td>Upper Target</td><td rowspan="2">10</td></tr>
<tr><td>2341.2</td><td>2370.6</td></tr>
<tr><td>Net Income ($M)</td><td colspan="2">160.6</td><td>40</td></tr>
</table>

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 100:

Reference(s): JTC2.18

Toronto Hydro notes that there were errors made to the box construction poles forecast in interrogatory responses 2B-AMPCO-24(a), 2B-SEC-51, and 2B-VECC-15. Please a) update the interrogatories as applicable for 2018 actuals, b) make the noted corrections.

RESPONSE:

The update and correction to Toronto Hydro's response to interrogatory 2B-AMPCO-24 (a) is set out in Table 1 and Table 2 below.

Table 1: Number of Box Construction Poles Replaced (Actuals)

Year	2013	2014	2015	2016	2017	2018
Units	102	818	727	978	717	586

Table 2: Number of Box Construction Poles Replaced (Forecast)

Year	2019	2020	2021	2022	2023	2024
Units	1,060	4,100[1]				

Please refer to Toronto Hydro's response to U-AMPCO-130 for the updates and corrections to its response to 2B-SEC-51.

[1] This figure consists of the corrected figure identified in JTC2.18, plus the additional carry-over poles discussed in Exhibit U, Tab 2, Schedule 2, at page 11.

The update to Toronto Hydro's response to 2B-VECC-15 (a) is that as of the end of 2018, there are approximately 6,200 Box Construction poles remaining on the system. At the end of 2024, Toronto Hydro forecasts that there will be approximately 1,100 Box Construction poles on the system.

Please see the table below for the update and correction to the utility's response to 2B-VECC-15 (b).

Table 3: Amended to include Box Construction Poles

	Actual				Bridge	Forecast				
	2015	2016	2017	2018	2019	2020[2]	2021	2022	2023	2024
Box Construction Conversion ($M)	19.6	13.6	18.7	29.4	30.5	23.2	20.8	21.1	22.0	20.7
# of Box Conversion Poles Replaced	727	978	717	586	1,060	4,100[3]				

[2] The 2020 expenditure figure has been updated for the changes discussed in response to U-Staff-168.
[3] See footnote 1 on the previous page.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 101:

Reference(s): 2B-SEC-52

Please update the interrogatory response to include 2018 actuals.

RESPONSE:

This intervenor Excel file has been updated to include 2018 actuals as well as revised 2019 and 2020 forecasts. A PDF version of the updated table is attached as Appendix A to this interrogatory response.

U-SEC-101 Appendix A

Program		EB-2014-0116 Application ($M)					Actual/Forecast ($M)					EB-2018-0165 Proposal ($M)				
		2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
E6.1	Underground Circuit Renewal	-96	80.10	84.00	99.70	99.50	115.49	80.68	83.10	69.07	55.82	92.95	88.74	90.29	93.13	95.17
E6.2	Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	3.45	1.38	0.73	0.81	0.51	6.01	5.74	1.83	0.84	0.13	0.00	0	0	0	0
E6.3	Underground Legacy Infrastructure	2.06	6.69	6.64	6.48	5.52	7.43	9.88	9.00	2.70	6.02	0.00	0	0	0	0
E6.4	Overhead Circuit Renewal	44.00	23.00	24.90	25.30	30.30	61.00	51.02	35.65	30.39	24.82	49.83	50.4	51.29	56.46	57.69
E6.5	Overhead Infrastructure Relocation	0.74	1.38	1.83	2.28	3.64	0.87	3.11	2.59	0.32	1.63	0.00	0	0	0	0
E6.6	Rear Lot Conversion	17.05	8.06	10.30	10.30	13.60	26.67	14.50	8.20	4.99	5.49	18.76	26.33	25.22	28.33	14.86
E6.7	Box Construction Conversion	16.80	20.70	21.10	21.60	22.70	19.59	13.65	18.66	29.37	30.47	23.16	20.84	21.08	22.02	20.7
E6.8	SCADA-MATE R1 Replacement	6.16	4.11	2.68	-	-	3.50	4.88	2.11	1.07	1.94	0.00	0	0	0	0
E6.9	Network Vault Rebuild Program	3.95	10.37	10.29	10.25	10.24	4.55	8.03	2.32	6.62	18.24	5.98	6.1	6.22	6.31	6.45
E6.10	Network Unit Renewal Program	3.95	10.37	10.29	10.25	10.24	4.72	7.64	8.29	7.49	-	9.49	9.81	10	10.14	10.15
E6.11	Legacy Network Equipment Replacement (ATS & RPB)	0.45	0.98	1.14	0.91	1.14	0.98	1.09	3.34	3.95	1.61	1.92	1.95	1.19	0	0
E6.12	Network Circuit Reconfiguration	0.00	2.30	2.29	2.28	2.27	0.00	0.00	0.74	0.69	3.67	1.20	1.43	1.11	1.21	1.73
E6.13	Stations Switchgear Renewal	11.90	18.90	25.50	27.60	22.40	7.70	5.51	8.46	7.45	9.49	19.74	25.76	19.27	16.58	9.91
E6.14	Stations Power Transformer Renewal	1.68	2.61	2.58	2.72	2.72	0.88	1.36	3.08	4.63	3.98	3.52	3.27	3.01	3.05	3.12
E6.15	Stations Circuit Breaker Renewal	1.66	1.80	1.79	2.11	1.78	2.28	2.50	3.06	2.62	1.97	0.90	0.67	1.12	1.14	1.61
E6.16	Stations Control & Monitoring	0.08	0.94	1.11	1.49	1.44	0.32	1.34	2.93	3.01	4.06	2.90	4.32	4.4	4.47	6.01
E6.17	Stations Ancillary Systems	0.69	0.59	0.37	0.26	0.38	0.00	0.03	0.07	0.59	1.49	0.22	0.32	0.62	0.63	0.65
E6.18	Stations Buildings	0.50	2.50	2.30	2.60	3.30	3.20	2.80	1.60	1.10	1.10	2.90	3.8	8.3	9	8.7
E6.19	Stations DC Battery Replacement	0.27	0.67	0.71	0.74	0.73	0.12	0.82	1.36	3.55	0.97	0.73	0.92	0.99	1.1	1.08
E6.20	Reactive Capital	31.90	32.70	33.10	33.60	34.20	38.99	50.19	52.50	62.25	59.51	56.39	57.48	58.49	59.36	60.66
E6.21	Worst Performing Feeder	1.80	1.80	1.80	1.80	1.80	3.03	4.09	2.97	3.87	4.23	4.79	4.88	4.97	5.05	5.16
E6.22	Distribution System Communication Infrastructure	6.06	6.02	3.95	-	-	0.00	2.03	4.77	5.82	7.50	2.23	2.38	2.1	2.14	2.07

Please completed the shaded era

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 102:

Reference(s): JTC3.6, Appendix A

Please update the interrogatory response to include 2018 actuals. (Please also provide include in your response the table in excel format)

RESPONSE:

Please refer to Appendix A of this response.

In providing this information, Toronto Hydro maintains the limitations and qualifications outlined in its responses to interrogatory 4A-SEC-87, part (b), and undertaking JTC3.6.

Updated JTC3.6 Appendix A
OEB Appendix 2-K
EMPLOYEE COSTS /COMPENSATION TABLE

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test	2021 Projection	2022 Projection	2023 Projection	2024 Projection
Number of Employees (FTEs including Part-Time)										
Executive	6	6	7	5	5	5	5	5	5	5
Managerial	55	63	63	67	63	62	63	63	63	63
Non Management, Non-Union	495	521	549	564	607	603	610	610	610	610
Society	53	56	60	65	68	69	69	69	69	69
PWU	874	837	794	724	779	778	797	797	797	797
Total	1483	1484	1473	1425	1523	1517	1544	1544	1544	1544
Total Salary and Wages (including ovetime and incentive pay)										
Executive	$ 2,486,891	$ 2,397,404	$ 2,704,552	$ 2,378,602	$ 2,369,718	$ 2,447,034	$ 2,510,069	$ 2,583,737	$ 2,659,837	$ 2,738,448
Managerial	$ 9,805,887	$ 11,755,405	$ 12,267,327	$ 13,340,028	$ 13,109,022	$ 13,272,778	$ 13,844,190	$ 14,277,271	$ 14,724,649	$ 15,186,974
Non Management, Non-Union	$ 52,575,387	$ 55,121,586	$ 58,799,211	$ 63,677,023	$ 69,086,145	$ 70,786,074	$ 73,543,113	$ 75,917,742	$ 78,368,180	$ 80,899,710
Society	$ 6,273,163	$ 6,387,993	$ 7,345,852	$ 7,857,253	$ 8,730,321	$ 9,026,473	$ 9,135,492	$ 9,276,139	$ 9,410,531	$ 9,546,705
PWU	$ 87,126,813	$ 84,638,474	$ 81,994,788	$ 79,475,009	$ 82,701,776	$ 83,908,086	$ 87,750,357	$ 90,205,825	$ 92,639,490	$ 95,107,337
Total	$ 158,268,141	$ 160,300,862	$ 163,111,731	$ 166,727,914	$ 175,996,982	$ 179,440,444	$ 186,783,221	$ 192,260,714	$ 197,802,688	$ 203,479,175
Total Benefits (Current + Accrued)										
Executive	$ 598,384	$ 566,562	$ 632,406	$ 539,960	$ 639,810	$ 706,901	$ 728,164	$ 751,670	$ 775,851	$ 800,022
Managerial	$ 2,974,938	$ 3,352,572	$ 3,570,450	$ 3,766,985	$ 4,006,639	$ 4,344,315	$ 4,554,021	$ 4,707,312	$ 4,864,976	$ 5,017,854
Non Management, Non-Union	$ 16,711,133	$ 17,268,194	$ 18,482,452	$ 18,694,608	$ 22,685,770	$ 24,854,001	$ 25,902,470	$ 26,803,377	$ 27,726,571	$ 28,589,965
Society	$ 2,186,586	$ 2,147,661	$ 2,485,728	$ 2,558,950	$ 2,702,876	$ 2,981,200	$ 3,041,149	$ 3,100,646	$ 3,160,919	$ 3,211,829
PWU	$ 30,356,391	$ 28,722,633	$ 28,143,352	$ 25,433,165	$ 26,864,459	$ 29,136,946	$ 30,623,764	$ 31,612,859	$ 32,620,296	$ 33,530,859
Total	$ 52,827,432	$ 52,057,622	$ 53,314,387	$ 50,993,668	$ 56,899,553	$ 62,023,363	$ 64,849,569	$ 66,975,864	$ 69,148,612	$ 71,150,529
Total Compensation (Salary, Wages, & Benefits)										
Executive	$ 3,085,275	$ 2,963,967	$ 3,336,959	$ 2,918,562	$ 3,009,528	$ 3,153,935	$ 3,238,233	$ 3,335,406	$ 3,435,688	$ 3,538,470
Managerial	$ 12,780,825	$ 15,107,977	$ 15,837,777	$ 17,107,012	$ 17,115,660	$ 17,617,093	$ 18,398,211	$ 18,984,583	$ 19,589,625	$ 20,204,828
Non Management, Non-Union	$ 69,286,521	$ 72,389,780	$ 77,281,663	$ 82,371,631	$ 91,771,915	$ 95,640,075	$ 99,445,583	$ 102,721,119	$ 106,094,752	$ 109,489,675
Society	$ 8,459,748	$ 8,535,654	$ 9,831,580	$ 10,416,204	$ 11,433,197	$ 12,007,672	$ 12,176,641	$ 12,376,785	$ 12,571,449	$ 12,758,534
PWU	$ 117,483,204	$ 113,361,107	$ 110,138,140	$ 104,908,173	$ 109,566,235	$ 113,045,032	$ 118,374,121	$ 121,818,684	$ 125,259,786	$ 128,638,197
Total	$ 211,095,573	$ 212,358,484	$ 216,426,119	$ 217,721,582	232,896,535	$ 241,463,807	$ 251,632,790	$ 259,236,578	$ 266,951,300	$ 274,629,704

Notes:
Please see Toronto Hydro's response to interrogatory 4A-SEC-87 part b) for the assumptions and limitations associated with the 2021-2024 information.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 103:

Reference(s): 8-SEC-94

Please update the interrogatory response. (Please also provide include in your response the table in excel format).

RESPONSE:

Please see Appendix A to this response.

RESPONSE to U-SEC-103

Table 1: 2005-2024 Base Distribution Charges

Customer Class	Charges[1]	Charge unit	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020 Proposed	2021 Proposed	2022 Proposed	2023 Proposed	2024 Proposed
Residential	Service Charges	$ per 30 days	13.64	11.96	12.00	14.85	16.85	18.25	18.25	18.25	19.16	19.36	18.63	22.78	27.69	32.63	37.48	42.17	43.54	44.61	46.50	48.33
	Distribution Volumetric Charges	$/kWh	0.01730	0.01540	0.01550	0.01550	0.01432	0.01572	0.01520	0.01520	0.01582	0.01599	0.01538	0.01880	0.01512	0.01063	0.00553					
Competitive Sector Multi-Unit Residential[2]	Service Charges	$ per 30 days									17.84	18.03	17.35	19.07	22.94	26.80	30.58	33.32	34.41	35.26	36.76	38.20
	Distribution Volumetric Charges	$/kWh									0.02692	0.02720	0.02617	0.02877	0.02315	0.01627	0.00846					
General Service <50 kW	Service Charges	$ per 30 days	18.27	16.02	16.07	19.37	21.44	24.30	24.30	24.30	25.50	25.77	24.80	30.47	32.68	34.45	35.80	37.23	38.44	39.39	41.06	42.67
	Distribution Volumetric Charges	$/kWh	0.02070	0.01840	0.01850	0.01990	0.01975	0.02270	0.02247	0.02247	0.02358	0.02383	0.02293	0.02818	0.03023	0.03187	0.03312	0.03444	0.03556	0.03643	0.03797	0.03946
General Service 50-999 kW	Service Charges	$ per 30 days	29.23	25.74	25.82	29.78	32.69	35.49	35.56	35.56	37.32	37.71	36.29	43.82	47.00	49.55	51.50	52.19	53.89	55.22	57.56	59.82
	Distribution Volumetric Charges	$/kVA per 30 days	5.6300	4.9600	4.9800	5.2600	5.1509	5.5840	5.5956	5.5956	5.8720	5.9341	5.7116	6.8970	7.3977	7.7987	8.1052	8.3724	8.6453	8.8580	9.2336	9.5965
General Service 1,000-4,999 kW	Service Charges	$ per 30 days	803.72	715.08	717.42	725.80	705.35	659.80	686.46	686.46	720.40	728.02	700.68	837.09	897.86	946.52	983.72	940.29	974.85	998.83	1041.18	1082.10
	Distribution Volumetric Charges	$/kVA per 30 days	4.6600	4.1500	4.1600	4.4100	4.3230	4.0438	4.4497	4.4497	4.6696	4.7190	4.5419	5.4262	5.8201	6.1355	6.3766	6.6114	6.8554	7.0240	7.3218	7.6095
Large Use	Service Charges	$ per 30 days	3070.72	2749.29	2758.30	2883.81	2639.04	2874.02	3009.11	3009.11	3157.88	3191.30	3071.47	3694.97	3963.22	4178.03	4342.23	4137.37	4272.25	4377.35	4562.95	4742.27
	Distribution Volumetric Charges	$/kVA per 30 days	3.9500	3.5400	3.5500	3.9100	3.9348	4.2852	4.7406	4.7406	4.9749	5.0275	4.8388	5.8210	6.2436	6.5820	6.8407	7.1267	7.3590	7.5400	7.8597	8.1686
Street Lighting	Service Charges (per device)	$ per 30 days	0.29	0.26	0.26	0.66	0.89	1.32	1.30	1.30	1.36	1.37	1.32	1.37	1.47	1.55	1.61	1.66	1.71	1.75	1.82	1.89
	Distribution Volumetric Charges	$/kVA per 30 days	4.0800	3.5900	3.6000	15.3700	19.7581	29.2169	28.7248	28.7248	30.1450	30.4640	29.3201	30.4431	32.6533	34.4231	35.7759	36.9560	38.1608	39.0996	40.7574	42.3592
Unmetered Scattered Load	Service/Connection Charges	$ per 30 days	2.55	2.27	2.28	3.29	3.77	5.42	5.33	5.33	5.59	5.65	5.44	6.70	7.19	7.58	7.14	6.43	6.64	6.80	7.09	7.37
	Distribution Volumetric Charges	$/kWh	0.02010	0.01790	0.01800	0.03670	0.04174	0.06090	0.06070	0.06070	0.06373	0.06440	0.06195	0.07634	0.08188	0.08632	0.08971	0.08073	0.08336	0.08541	0.08903	0.09253

Note 1: The Charges include ICM Rate Riders

Note 2: Competitive Sector Multi-Unit Residential rates were first approved as part of 2013 Toronto Hydro Decision and Order (EB-2012-00-64)

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 104:

Reference(s): Evidence Overview Presentation, p. 6

Please provide the underlying data tables used in the total capital and OM&A expenditure graphs. Please ensure the tables have both the unadjusted amounts and the OEB inflation numbers used for the purposes of the adjustment.

RESPONSE:

Please see Appendix A.

2010-2024 Inflation Adjusted Capital Expenditures

$ millions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Capital Expenditures before inflation adjustment	400.6	445.5	288.0	445.7	585.6	491.4	511.6	497.8	447.8	434.9	518.4	581.8	587.1	565.7	574.4
Annual OEB Inflation Prescribed Value	1.3%	1.3%	2.0%	1.6%	1.6%	1.6%	2.1%	1.9%	1.2%	1.5%	1.2%	1.2%	1.2%	1.2%	1.2%
Calculated Inflation	48.4	47.4	26.6	31.6	31.6	18.4	10.7	0.0	-5.3	-11.5	-19.7	-28.8	-35.6	-40.6	-47.6
Inflation Adjusted CapEx	449.0	492.9	314.5	477.2	617.2	509.8	522.3	497.8	442.5	423.4	498.7	553.1	551.5	525.1	526.8

2011-2020 Total OM&A Expenditures

$ millions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total OM&A before inflation adjustment	238.6	243.5	246.4	241.1	244.0	249.8	255.3	268.3	268.2	277.5
Annual OEB Inflation Prescribed Value	1.3%	2.0%	1.6%	1.6%	1.6%	2.1%	1.9%	1.2%	1.5%	1.2%
Calculated Inflation	30.4	27.5	22.5	17.8	13.9	10.1	4.9	0.0	-4.0	-7.3
Inflation Adjusted OM&A	269.0	271.0	268.9	258.9	257.9	259.9	260.1	268.3	264.2	270.2

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 105:

Reference(s): Evidence Overview Presentation, p. 15

a) Please expand the SAIFI chart to include (a) 2018 data, and b) forecast 2019 to 2022 SAIFI levels.

b) Please provide a similar chart as requested in part (a) for SAIDI.

c) Please provide a table showing numerical values for the charts requested in parts (a) and (b).

RESPONSE:

a) Please see the chart below with a projection for 2019-2024.

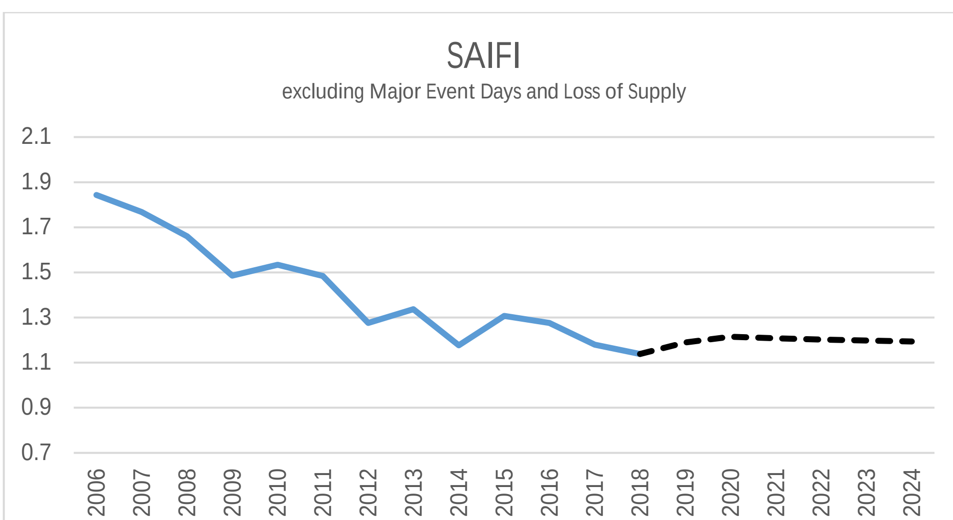


Figure 1: SAIFI Projections for 2019-2024 (excluding MED and LoS)

b) Please see the chart below with a projection for 2019-2024.

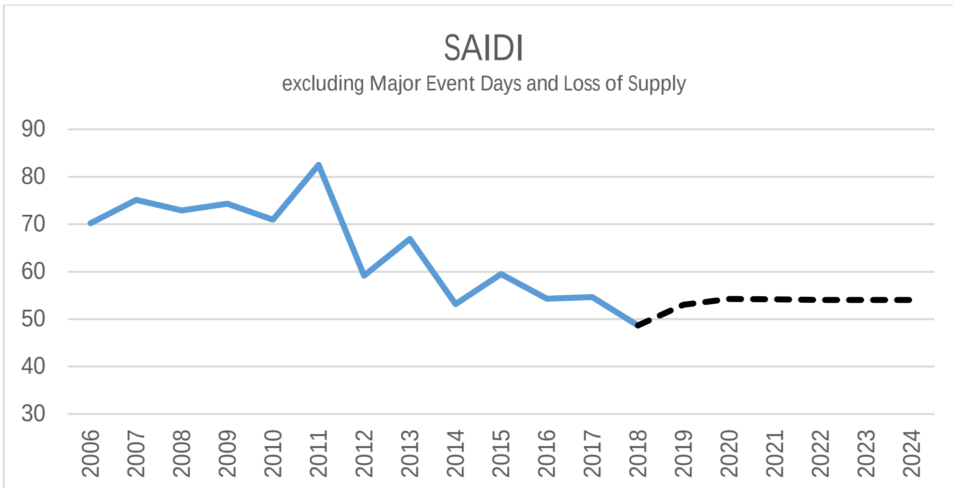


Figure 2: SAIDI Projections for 2019-2024 (excluding MED and LoS)

c) Please see Table 1. Please note that:

1. 2018 performance is considered to be an outlier due to performance in some cause codes (e.g. Lightning and Scheduled Outages for SAIFI) and the exclusion of five major event days (i.e. 1.4 percent of the year) from the statistics.

2. The projections reflect expected trends for performance and are not intended to be targets. Toronto Hydro's experience has been that due to considerable volatility from one year to the next with specific cause codes – including Tree Contacts, Adverse Weather, Foreign Interference, Human Element, and Unknown – it is very likely that actual performance will fall within a broader band than illustrated by the charts in part (a) and (b). For example, volatility experienced between 2015 and 2018 suggests that performance may vary by as much as, or more than, 10 percent from one year to the next. Please see

Exhibit U, Tab 1B, Schedule 1, pages 30 and 31 for additional details in respect of cause code volatility and trends.

Table 1: SAIDI and SAIFI Data for Figure 1 and Figure 2

Year	SAIFI Historical	SAIFI Projection	SAIDI Historical	SAIDI Projection
2006	1.84		70.21	
2007	1.77		75.12	
2008	1.66		72.89	
2009	1.49		74.33	
2010	1.53		70.94	
2011	1.48		82.53	
2012	1.28		59.20	
2013	1.34		66.92	
2014	1.18		53.19	
2015	1.31		59.49	
2016	1.28		54.34	
2017	1.18		54.64	
2018	1.14		48.67	
2019		1.19		53.03
2020		1.21		54.26
2021		1.21		54.16
2022		1.20		54.06
2023		1.20		54.02
2024		1.19		54.06

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 106:

Reference(s): Update – Schedules

Please file, in Excel format, the OEB PILs model and the Revenue Requirement Work Forms for 2020 to 2024, adjusted for the impacts of Bill C-97, the federal government bill to implement the 2018 Fall Economic Statement and the 2019 Budget.

RESPONSE:

Please see Toronto Hydro's response to interrogatory U-Staff-188.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 107:

Reference(s): Update – Schedules

Based on the results of U-SEC-106, and assuming the changes meet the materiality threshold, please file updated versions of the following (in Excel format where applicable):

a) Cost allocation model.

b) Appendix 2-N, Shared Services

c) Appendix 2-OB, Capital and Debt

d) Appendix 2-W, Bill Impacts

e) The evidence of PSE, including the supplementary report, or a statement that the PSE evidence is not affected by the tax changes

f) To the extent, if any, that the tax changes will result in changes to capital expenditures, or changes to the amount of contributions to be received by the Applicant, Appendices 2-AA and 2-AB, Capital Expenditures, Appendix 2-BA, Fixed Asset Continuity Schedule, and Appendix 2-C, Depreciation and Amortization Expense, for all relevant years.

g) Any other evidence of the Applicant, whether original, updated, or in response to interrogatories, that, if not updated to reflect the tax changes, would be misleading or confusing for the Board.

RESPONSE:

Please refer to Toronto Hydro's response to U-Staff-188 for responses to parts (a) to (d) and (f) to (g) of this interrogatory.

RESPONSE (PREPARED BY PSE):

e) The total cost benchmarking results and related PSE evidence are not affected by the tax changes noted in U-SEC-106.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 61:

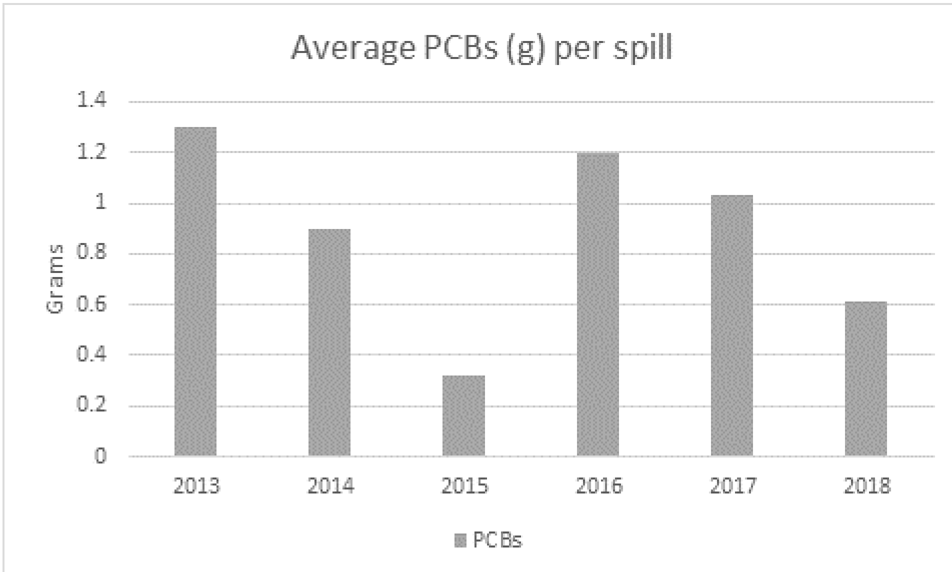
Reference(s): Exhibit U, Tab 1B, Schedule 1, p. 15

What reason/event account for the increase in PCB spills in 2018 following 3 years of declines in these occurrences?

RESPONSE:

There was no single reason/event that contributed to an increase in PCB spills in 2018. Toronto Hydro's Oil Spills Containing PCBs measure tracks progress towards reducing the risk of oil spills containing PCBs. To help decrease the likelihood of major spills, the utility has improved its efforts to proactively identify and report minor PCB-contaminated oil spills. This is one contributing factor to the results in 2018. The results of these efforts are seen in Figure 1 below, which shows that while the total number of spills increased in 2018, the average amount of PCBs released from these spills was lower than the previous two years.

In general, while Toronto Hydro expects to improve on the performance of this measure over the 2020-2024 period, the number of PCB-contaminated oil spills is also expected to vary from year to year due to the volatility of the measure as it is driven by asset failures across the system.



1 Figure 1: Average PCB Content Per Spill

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 62:

Reference(s): **Exhibit U, Tab 1B, Schedule 1, p. 17**

2018 MAIFI performance reinforces a long terms trend which appears to show no discernible improvement in reducing momentary outages over the past 6 years and notwithstanding improvements in the reducing the outages due to defective equipment. Please comment on why this is, specifically what are the main drivers of momentary outages?

RESPONSE:

Toronto Hydro does not believe the MAIFI results and trends fully reflect the frequency of momentary interruptions on the system. As previously described in 1B-Staff-14, Toronto Hydro's ability to measure MAIFI is limited by manual processes and incomplete SCADA coverage. Where prudent, Toronto Hydro continues to install monitoring and control systems at stations where there is currently a lack of SCADA coverage. The utility will also continue to convert customers currently served by 4 kV stations over to 13.8 kV or 27.6 kV stations that have SCADA coverage. Improving SCADA coverage over time has meant, and will continue to mean, that more momentary interruptions will be captured. This in turn means that even if underlying MAIFI results are improving across the system, this trend is offset to a certain extent by increases in MAIFI from improved SCADA coverage.

It is also important to note that momentary interruptions are in part a design feature of a reliable electricity system. When an interruption occurs and the breaker automatically recloses successfully, this operation is designed to ensure that customers are minimally impacted during a fault, i.e. they do not experience a sustained interruption as a result. When a momentary fault has cleared, it is difficult to troubleshoot and identify the root cause of the interruption, as it could have occurred anywhere along a feeder that spans several kilometers. To try to identify the root cause, crews would need to be sent out to patrol the entire feeder, and this would not be a cost-effective use of resources, except in situations where there are an unusual number of momentary outages occurring on a feeder over a period of time.

Toronto Hydro has a number of initiatives to help manage MAIFI performance. These include:

- Tree-proof conductors are being installed as part of the Overhead System Renewal program to reduce vegetation contact risk (See Exhibit 2B, Section E6.5). This will help reduce momentary interruptions caused by tree contact.

- Toronto Hydro makes efforts to try to reduce outages of Unknown causes, (whether sustained or momentary), through its maintenance and inspection programs. Examples of how these activities help to improve MAIFI include tree trimming to reduce tree contact risk, insulator washing to reduce insulator flash over risk, etc.

- Toronto Hydro has also been developing tools which can help to identify approximate locations of the fault and, through machine learning, identify the potential cause of the interruption. This can help resolve instances where repeated issues occur at the same location.

- As discussed in 2B-HANN-80, Toronto Hydro is currently studying the installation of re-closers on the feeder trunk to reduce the impact of momentaries on feeders that are experiencing numerous momentary interruptions.

Please refer to Toronto Hydro's response to Interrogatory U-EP-66, part (a), for a summary of the typical causes of momentary interruptions.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 63:

Reference(s): Exhibit U, Tab 1B, Schedule 1, pp. 20-21

What accounts for the continuing inability to meet the OEB standard for Appointment Scheduling?

RESPONSE:

Toronto Hydro has improved its performance by 14 percent in the last two years and continues to work on its performance against this measure. The recent underperformance is primarily a result of reliance on reports from the Ontario One Call system, combined with a rapid increase in the volume of appointments Toronto Hydro has been required to schedule. Table 1 below shows the individual components that make up the 2018 reported results and further demonstrates that Toronto Hydro has excellent performance in all areas outside of Locates. Toronto Hydro also notes that the Locates area is the component that contributes the largest number appointments to the calculation of the measure and therefore the largest driver of the annual result.

Table 1: Breakdown of 2018 Appointment Scheduling Results by Operational Area

	Area				
	Program Delivery	Meter Data Management	Locates (as reported by Ontario One Call)	Escalations and Special Investigations	Conservation Demand Management
Appointment Scheduling Component Result	100%	100%	81%	100%	99%

With respect to the Locates area, the Ontario One Call system provides Toronto Hydro performance data related to the equipment locates performed on behalf of the utility. The data is processed in a way which incorrectly shows tickets as incomplete even though the customer has agreed to an appointment time outside of the five-day window. Toronto Hydro is in the process of developing systems to enable an internal system-of-record for the 180,000 equipment locates it performs each year that includes consideration of these negotiated appointments.

As noted in Exhibit 1B, Tab 1, Schedule 1, page 12, Toronto is a growing city and this is further demonstrated by the volume of appointments increasing from 96,000 in 2013 to over 188,000 in 2018 (see Figure 1 below). The implemented improvements shown in Exhibit 1B, Tab 2, Schedule 3, page 4 have helped to offset the challenge of responding and managing this rapid volume increase and further improve efficiencies. Toronto Hydro has also engaged two additional service providers to further increase its capacity and ability to handle seasonal variations. As such Toronto Hydro expects its performance to further improve.

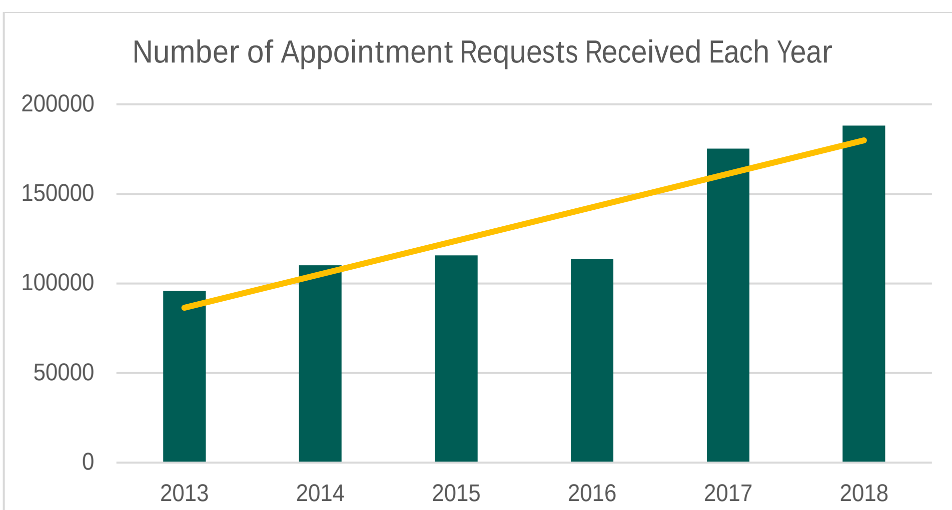


Figure 1: The Volume of Appointment Requests Received by Toronto Hydro Each Year

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 64:

Reference(s): Exhibit U, Tab 1B, Schedule 1, pp. 25-26

THESL explains that the degradation in reliability (not supply related) in 2018 was due to adverse weather events, specifically three wind storms and freezing rain. In determining whether events should be classified as Major Event Days, does THESL use objective weather criteria (e.g. wind speed etc.) or is a major event day classified, by the number of outages on an adverse weather day?

RESPONSE:

Toronto Hydro uses the IEEE Standard 1366 2.5 Beta method as per the OEB Electricity Reporting and Record Keeping Requirements to define a Major Event Day (MED) with respect to distribution reliability performance.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 65:

Reference(s): Exhibit U, Tab 1C, Schedule 2, Financial Statements, p. 6

The 2018 Statement of Income shows a large gain on disposal of $108.6 in 2018. Please explain what this relates to and specifically if it relates to the Executive Summary notes in the Management's Discussion and Analysis which discusses a gain of 98.6 million for the sale of property.

RESPONSE:

The $108.6 million shown in the 2018 Statement of Income is comprised of $108.0 million related to the sale of property and $0.6 million related to sale of fleet. The $98.6 million as disclosed in the MD&A is the gain on sale of the property, net of tax of $9.4 million. This property is located at 5800 Yonge Street, and was disposed of as part of the Operating Centers Consolidation Program ("OCCP"). As noted in Exhibit 9, Tab 1, Schedule 1, page 32, Toronto Hydro proposes to return the incremental gain on this property to customers through the OCCP rate rider.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 66:

Reference(s): Exhibit U, Tab 2, Schedule 1, pp. 8-9

THESL explains that it is seeking to increase the 2020 revenue requirement by $1.6 million for an increase in working capital due to revised Customer Service Rules. Please provide the detailed calculation which sets out the increase of $1.6 million. Is it THESL's intent to file a revised lead-lag study?

RESPONSE:

Please see the response to U-Staff-169 for the detailed calculations.

No, Toronto Hydro does not intend to file a revised lead-lag study.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 67:

Reference(s): **Exhibit U, Tab 2, Schedule 2, p. 5**

a) Please update Table 9 at Exhibit 2B/Section 7.2/p.32 (2B-Staff-91) to show the revised Bridge and Forecast Metrolinx related projects.

b) Please revise Table 9 to show the gross capital investments in each year and the expected capital contributions.

c) Please also update the Tables provided in response to 2B-SEC-55

RESPONSE:

a) Please see Table 1 below.

Table 1: Actual, Bridge & Forecast Customer-Specific ESS ($ Millions)

	Actual	Bridge	Forecast					
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
Metrolinx ECLRT	8.4	19.4						**27.8**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC eBus Support			14.2					**14.2**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**8.5**	**19.5**	**26.2**	**12.1**	**5.9**	**0**	**0**	**72.2**

At the request of the customer, the Toronto Transit Commission (TTC), Toronto Hydro has divided the TTC Arrow Garage project into three smaller projects located at the

TTC Arrow Garage, TTC Eglinton Garage, and TTC Mt. Dennis Garage. This project has been renamed TTC eBus Support. The ESS projects will provide enhanced distribution system support for the TTC garage facilities that are hosting electricity-intensive eBus chargers. Installing, owning, and operating the chargers themselves are not part of the Toronto Hydro program. The ESS units will be primarily used to support electric bus charging (i.e. peak load shaving, electricity supply to bus chargers, etc.).

This change in scope has resulted in a cost increase of $1.8 million, however, these costs will not impact rate base as they are 100% recoverable through capital contributions from the TTC.

b) The capital contributions for each project are provided in Table 2 below. These projects are fully recoverable, therefore, the capital contributions equal the project costs.

Table 2: Actual, Bridge & Forecast Customer-Specific ESS Capital Contributions ($ Millions)

	Bridge		Forecast					Total
	2018	2019	2020	2021	2022	2023	2024	
Metrolinx ECLRT	8.4	19.4						**27.8**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC Ebus Support			14.2					**14.2**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**8.5**	**19.5**	**26.2**	**12.1**	**5.9**	**0**	**0**	**72.2**

c) Tables 1 to 5, provided in response to 2B-SEC-55, are updated below.

As stated in the Application Update in Exhibit U, Tab 2, Schedule 2, Section 1.2.2, amounts related to the Metrolinx ECLRT were shifted from 2018 to 2019 due to project delays outside of Toronto Hydro's control. Other notable changes are amounts related to Metrolinx's Regional Express Rail program, where portions were accelerated to 2019 and 2020 as early relocation works, of which 100% of the costs are recoverable; and the deferral of the City of Toronto John Revitalisation project due to third-party schedules (see Table 5).

Additionally, variances in expenditures and timing are also attributed to the MTO Bridge Rehabilitation Program work. As stated in Toronto Hydro's original response to interrogatory 2B-SEC-55 and in Exhibit 2B, Section E5.2, the utility only included forecast expenditures for projects with committed capital contributions. For this particular project, Toronto Hydro started to secure project level funding in late 2018, with majority of the commitments being secured in 2019. As highlighted in Table 6 of this response, the majority of the MTO bridge rehabilitation relocation program costs are recoverable, where projects to be completed before 2019 are fully recoverable. Net expenditures included in 2020 reflect future year funding that is yet to be secured by MTO.

As stated in Exhibit 2B, Section E5.2.3.2, the scope, timing, and pacing of externally initiated relocation projects are driven by operational and planning decisions of third parties, which are beyond Toronto Hydro's control. These shifts and their effects for ratepayers are captured in and mitigated by the Variance Account for Externally Driven Capital, which Toronto Hydro is requesting the continuation of in this application for the 2020-2024 period.

Table 1: Metrolinx Eglinton Crosstown LRT Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	0.96	1.5	7.3	8.6	8.8	17.3	14.0	0	0	0
Capital Contributions	0.47	(1.8)	(7.2)	(8.7)	(2.9)	(9.3)	(3.9)	0	0	0
Net	**0.49**	**-0.28**	**0.10**	**-0.10**	**5.9**	**8.0**	**10.1**	**0**	**0**	**0**

Table 2: Metrolinx Finch West LRT Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	0	0	0.26	0.44	0.8	12.1	17.6	0	0	0
Capital Contributions	0	0	(0.24)	(0.44)	(0.8)	(12.1)	(10.5)	0	0	0
Net	**0**	**0**	**0.02**	**0**	**0**	**0**	**7.1**	**0**	**0**	**0**

Table 3: Metrolinx Regional Express Rail Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total Cost	0	0.02	0.48	0.32	22.6	32.1	24.2	24.2	24.2	24.2
Capital Contributions	0	0	(0.45)	(0.32)	(22.6)	(32.1)	(24.2)	(24.2)	(24.2)	(24.2)
Net	**0**	**0.02**	**0.03**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 4: TTC Easier Access Program Costs ($ Millions)[1]

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	0.44	0.55	0.38	0.22	1.9	0	0	0	0	0
Capital Contributions	0	(0.36)	(1.0)	(0.19)	(1.9)	0	0	0	0	0
Net	**0.44**	**0.19**	**(0.63)**	**0.03**	**0**	**0**	**0**	**0**	**0**	**0**

Note 1: As no commitment had been made at the time of the filing, there were no expenditures included in the 2020-2024 program costs.

Table 5: City of Toronto Projects Costs ($ Millions)[1]

Projects	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
John Revitalisation										
Total	0	0	0	0	0	2.4	3.5	5.9	0	0
Capital Contributions	0	0	0	0	0	(0.62)	(1.1)	(2.4)	0	0
Net	**0**	**0**	**0**	**0**	**0**	**1.7**	**2.4**	**3.5**	**0**	**0**
Wellington Street										
Total	0	0	0	1.4	3.06	0	0	0	0	0
Capital Contributions	0	0	0	0	(0.60)	0	0	0	0	0
Net	**0**	**0**	**0**	**1.4**	**2.46**	**0**	**0**	**0**	**0**	**0**
York-Bay-Yonge										
Total	0	0	0.12	0.07	0	0	0	0	0	0
Capital Contributions	0	0	0	(0.07)	0	0	0	0	0	0
Net	**0**	**0**	**0.12**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note 1: As no commitment had been made for the Harbour Street Widening at the time of the filing, there were no expenditures included in the 2020-2024 program costs. Subsequent to the application filing, the Harbour Street Widening project was cancelled.

Table 6: MTO Bridge Rehabilitation Program ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Total	0	2.9	0.3	4.8	20.4	4.2	0	0	0	0
Capital Contributions	0	(2.9)	0.3	(4.8)	(20.4)	(1.7)	0	0	0	0
Net	**0**	**0**	**0**	**0**	**0**	**2.5**	**0**	**0**	**0**	**0**

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 68:

Reference(s): **Exhibit U, Tab 2, Schedule 2, pp. 7-8**

Please list the $2.0 million in new monitoring and control initiatives which are incremental to the original forecast and now found subsequent to the $2.0 million reduction in capital expenditures on the bus-ties at the Leslie and Richview TS's.

RESPONSE:

The $2.0 million does not support "new" monitoring and control work. The work that the $2.0 million supports is described on page 8 of the referenced schedule, at lines 4 to 15.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 69:

Reference(s): **Exhibit U, Tab 2, Schedule 2, p. 13**

With respect to Overhead System Renewal, why did THESL significantly increase its capital spending in 2018 ($30.4 from forecast $18.4) and why is it proposing to exceed its original forecast spending in 2019 from $17.8m to $24.8m? Given this over budget spending is THESL proposing to reduce the $49.8 million proposed to be spent on these projects in 2020?

RESPONSE:

The increase in spending in 2018 and 2019 is primarily due to emerging needs on the overhead system in the Horseshoe area of Toronto Hydro's service area. As discussed in Exhibit U, Tab 2, Schedule 2, at page 14, the incremental work includes:

- Additional porcelain insulator replacements to mitigate the risk of pole fires;

- Additional circuit renewal work to address poor reliability on the system. This includes work on poor performing feeders in the western half of the City (e.g. Bathurst TS feeders serving large industrial customers), where some feeders experienced up to 8 sustained interruptions in one year, largely due to defective overhead equipment; and

- Voltage conversion projects to enable the urgent decommissioning of deteriorating municipal substation equipment (e.g. Leslie MS). Conversion work needed to be undertaken immediately to mitigate the risk of station equipment failure to due reasons such as corroded switchgear enclosures and lack of spare parts to repair station defective equipment.

This additional investment in the Overhead System Renewal program was enabled in part by the reprioritization of work in the Underground System Renewal – Horseshoe and Rear Lot Conversion projects.

Toronto Hydro is not proposing to reduce expenditures in this program in 2020. Due to the safety, reliability, and environmental risks demonstrated in Exhibit 2B, Section E6.5, Toronto Hydro plans to continue with the proposed pace of program investment in 2020-2024.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 70:

Reference(s): **Exhibit U, Tab 2, Schedule 2, p. 21**

Please update the response to Table 1 at 2B-VECC-13

RESPONSE:

Please see Table 1 below.

Table 1: System Access: 2015-2024 Expenditures ($ Millions)

		Actual				Bridge	Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
System Access	***Gross***	97.4	113.0	113.0	153.0	236.0	160.4	189.6	181.3	193.8	207.2
	Capital Contributions	(39.0)	(34.0)	(47.5)	(65.0)	(123.9)	(68.6)	(96.3)	(87.4)	(87.8)	(90.9)
	Net	**58.3**	**79.0**	**65.5**	**88.0**	**112.1**	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**

The increase in expenditures in 2019 is primarily driven by the timing of projects in the Externally Initiated Plant Relocations and Expansions program. Please refer to Toronto Hydro’s response to U-VECC-67, part (c) for more information.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 71:

Reference(s): **Exhibit U, Tab 2, Schedule 2, Appendix A, Appendix 2-AA**

a) Please provide a revised Appendix 2-AA which includes the 2018 original estimates for 2018 and 2019 (Sept 2018) and the variances as between each category in the original and revised Appendix 2-AA.

b) Please confirm that no changes are being proposed in Appendix 2-AA for the forecasts capital expenditure amounts for years 2020 through 2024. Or if this is not confirmed please provide similar revised columns and variances.

RESPONSE:

a) Please see Appendix A.

b) Please see Appendix A, which presents the updated 2020 through 2024 capital expenditures that includes an increase of $3.2 million in 2020 related to completion of certain projects that are carried over from 2019. Refer to Toronto Hydro's response to U-Staff-168 for more information.

U-VECC-71 Appendix A

	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2018 Actual	2019 Bridge	2019 Updated Bridge	2020 Test	2020 Updated Test	2021 Test	2022 Test	2023 Test	2024 Test	2018 Variance	2019 Variance	2020 Variance
Customer and Generation Connections	31.7	40.1	21.9	44.8	44.0	37.6	39.8	42.9	42.9	43.9	44.8	45.6	46.3	(0.8)	2.2	-
Externally Initiated Plant Relocations & Expansion	2.2	2.6	2.6	7.5	5.0	8.3	11.9	11.4	11.4	20.8	4.6	4.7	4.5	(2.5)	3.6	-
Generation Protection, Monitoring and Control	-	2.1	0.0	8.0	0.6	3.4	10.9	3.7	3.7	2.3	2.4	2.5	2.7	(7.4)	7.5	-
Load Demand	9.9	16.8	16.2	17.3	16.4	21.6	23.5	11.3	11.3	11.4	18.5	22.6	23.6	(0.9)	1.9	-
Metering	14.5	17.4	24.8	23.0	22.0	26.1	26.1	22.6	23.6	14.8	23.6	30.6	39.2	(1.0)	(0.1)	1.0
System Access Total	**58.3**	**79.0**	**65.5**	**100.8**	**88.0**	**97.1**	**112.1**	**91.8**	**92.8**	**93.3**	**93.9**	**106.0**	**116.4**	**(12.8)**	**15.0**	**1.0**
Area Conversions	46.3	28.2	26.9	40.0	34.4	44.4	36.0	41.4	41.9	47.2	46.3	50.4	35.6	(5.6)	(8.5)	0.5
Network System Renewal	10.2	16.8	14.7	18.9	18.8	29.8	32.2	18.6	18.6	19.3	18.5	17.7	18.3	(0.1)	2.4	-
Reactive and Corrective Capital	42.0	54.3	55.5	58.4	66.1	57.1	63.7	61.2	61.2	62.4	63.5	64.4	65.8	7.7	6.6	-
Stations Renewal	11.3	11.6	19.0	19.7	21.9	23.7	22.0	27.5	28.0	35.3	29.4	27.0	22.4	2.1	(1.8)	0.5
Underground Renewal - Downtown	-	-	-	-	(0.0)	-	-	15.1	15.1	22.5	23.9	30.0	30.6	(0.0)	-	-
Underground Renewal - Horseshoe	115.5	80.7	83.1	70.0	69.1	71.4	55.8	93.0	93.0	88.7	90.3	93.1	95.2	(0.9)	(15.6)	-
Overhead Infrastructure Relocation	0.9	3.1	2.6	0.2	0.3	-	1.6	-	-	-	-	-	-	0.2	1.6	-
SCADAMATE R1 Renewal	3.5	4.9	2.1	1.4	1.1	2.7	1.9	-	-	-	-	-	-	(0.4)	(0.8)	-
PILC Piece Outs & Leakers	6.0	5.7	1.8	0.1	0.8	1.5	0.1	-	-	-	-	-	-	0.7	(1.3)	-
Underground Legacy Infrastructure	7.4	9.9	9.0	2.3	2.7	5.0	6.0	-	-	-	-	-	-	0.3	1.0	-
Overhead System Renewal	61.0	51.0	35.7	18.4	30.4	17.8	24.8	49.8	49.8	50.4	51.3	56.5	57.7	12.0	7.0	-
System Renewal Total	**304.1**	**266.1**	**250.3**	**229.4**	**245.5**	**253.4**	**244.2**	**306.6**	**307.6**	**325.7**	**323.1**	**339.0**	**325.5**	**16.1**	**(9.2)**	**1.0**
Energy Storage Systems	-	-	-	5.9	0.1	2.0	7.9	1.0	1.0	3.7	3.8	1.0	1.0	(5.8)	5.9	-
Network Condition Monitoring and Control	-	-	-	-	-	-	-	7.6	8.0	10.2	12.6	15.3	17.4	-	-	0.4
Overhead Momentary Reduction	0.0	-	-	0.3	-	0.3	0.3	-	-	-	-	-	-	(0.3)	-	-
Stations Expansion	23.0	34.5	59.4	30.6	21.0	32.8	29.1	19.5	19.5	40.0	49.3	12.5	15.2	(9.5)	(3.7)	-
System Enhancements	7.1	17.2	12.2	4.0	9.4	6.7	4.0	6.2	6.2	6.2	5.6	4.8	4.9	5.4	(2.7)	-
Handwell Upgrades	4.7	0.8	0.8	-	0.0	-	-	-	-	-	-	-	-	0.0	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.6	0.4	-	-	-	-	-	-	-	-	(0.1)	-	-
Design Enhancement	0.0	0.6	(0.0)	-	0.0	-	0.2	-	-	-	-	-	-	0.0	0.2	-
System Service Total	**37.9**	**53.3**	**72.4**	**41.4**	**31.0**	**41.8**	**41.5**	**34.2**	**34.6**	**60.1**	**71.3**	**33.6**	**38.5**	**(10.3)**	**(0.3)**	**0.4**
Facilities Management and Security	15.4	9.0	6.3	2.1	1.7	2.5	3.5	11.6	11.6	11.8	12.1	12.3	12.6	(0.4)	1.0	-
Fleet and Equipment	4.1	3.7	4.7	3.3	2.9	3.3	3.6	8.6	8.6	8.9	8.5	8.7	7.8	(0.4)	0.3	-
IT/OT Systems	28.4	48.6	55.4	64.6	53.7	34.4	39.3	54.8	55.6	55.7	49.5	56.6	64.8	(10.9)	4.9	0.8
Control Operations Reinforcement	-	-	-	-	-	-	-	3.9	3.9	17.4	18.9	-	-	-	-	-
Operating Centers Consolidation Plan	31.6	48.3	32.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Program Support	-	0.0	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant Total	**79.4**	**109.5**	**98.9**	**70.0**	**58.4**	**40.2**	**46.4**	**78.8**	**79.6**	**93.7**	**89.0**	**77.7**	**85.2**	**(11.6)**	**6.2**	**0.8**
AFUDC	10.8	12.5	9.8	6.0	8.9	4.0	4.0	6.0	6.0	8.2	8.7	8.9	7.7	2.9	-	-
Miscellaneous	0.8	(8.8)	0.9	0.3	3.8	(1.6)	(5.3)	1.0	1.0	0.8	1.2	0.6	1.0	3.6	(3.7)	-
Other Total	**11.6**	**3.7**	**10.7**	**6.3**	**12.7**	**2.4**	**(1.3)**	**7.0**	**7.0**	**9.0**	**9.8**	**9.5**	**8.7**	**6.5**	**(3.7)**	**-**
Subtotal	**491.4**	**511.6**	**497.8**	**447.8**	**435.6**	**434.9**	**443.0**	**518.4**	**521.6**	**581.8**	**587.1**	**565.7**	**574.4**	**(12.2)**	**8.1**	**3.2**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.8)	(3.2)	(1.2)	(13.1)	(0.7)	(9.3)	(17.7)	(4.4)	(4.4)	(3.1)	(3.2)	(3.3)	(3.5)	12.4	(8.4)	-
Total	**490.6**	**508.4**	**496.6**	**434.7**	**434.9**	**425.7**	**425.3**	**514.0**	**517.2**	**578.8**	**583.9**	**562.4**	**570.9**	**0.3**	**(0.4)**	**3.2**

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 72:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 4-6;**
3-VECC-18

Preamble:

The response to 3-VECC-18 and the accompanying Appendix A suggest that for the Residential and GS 50-999 customer classes the linear trend models were based on historical data dating back to 2004.

a) Table 3 in the Exhibit U indicates that historical data back to 2002 was used for these classes for purposes of the Update. Please indicate if this is correct.

b) If so, please explain the reason for the change.

c) If so, please re-estimate the forecast 2019-2024 customer counts for these two classes using historical data back to 2004 (i.e. 2004-2018 data).

RESPONSE:

a) Correct.

b) The response to question 3-VECC-18 indicated a 2004 start date in error. The trends for the Residential and GS 50-999kW classes were estimated beginning in 2002 for both the original pre-filed evidence and the update.

c) Although both the original and the evidence update are based on 2002 as the starting year, as requested, Table 1 shows a customer forecast for Residential and GS 50-999 kW using only 2004-2018 historical data.

Table 1: Customer Forecast based on 2004-2018 linear trend

Rate Class	2019	2020	2021	2022	2023	2024
Residential	613,457	614,862	616,268	617,673	619,079	620,484
GS 50-999 kW	10,425	10,350	10,275	10,200	10,125	10,050

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 73:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 4-6;**
3-VECC-18

<u>Preamble:</u>

The response to 3-VECC-18 and the accompanying Appendix A suggest that for the GS<50 customer classes the linear trend models were based on historical data dating back to 2004.

a) Table 3 in the Exhibit U indicates that historical data back to 2014 was used for this class for purposes of the Update. Please indicate if this is correct.

b) If yes, please explain the reason for the change.

c) If so, please re-estimate the forecast 2019-2024 customer counts for this class using historical data back to 2004 (i.e. 2004-2018 data).

RESPONSE:

a) Correct.

b) There was no change in starting point for GS<50 kW class historical data. In both the pre-filed evidence and the evidence update, the starting point for the linear trend is 2014.

c) Table 1 shows a Customer forecast for GS < 50 kW using 2004-2018 historical data adjusted for FIT additions. FIT customers were adjusted from the historical data in order to be consistent with Toronto Hydro's forecast approach. Please refer to IR response 3-VECC-18, part (b) for more details. Toronto Hydro does not believe that using 2004 as the starting point produces a reasonable forecast for these classes, as a linear trend over the indicated period does not reflect the most recent data.

Table 1: Customer Forecast Based on 2004-2018 Data

Rate Class	2019	2020	2021	2022	2023	2024
GS <50 kW	71,572	71,917	72,261	72,605	72,950	73,294

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 74:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 4-6;**
3-VECC-18

Preamble:

The response to 3-VECC-18 and the accompanying Appendix A suggest that for the GS 1,000-4,999; Large Use and USL customer classes the linear trend models were based on historical data dating back to 2004.

a) Table 3 in the Exhibit U indicates that the latest actual data was used for these classes for purposes of the Update. Please confirm that this was the value as of December 2018 and explain the basis for the change in approach.

b) Please re-estimate the forecast 2019-2024 customer counts for these classes using a trend model based on historical data back to 2004 (i.e. 2004-2018 data).

RESPONSE:

a) Confirmed. For the update, December 2018 was used for these classes forecast. There was no change in the approach. In both the original pre-filed evidence and the update, the latest actual was used for forecast.

b) Table 1 shows a customer forecast for GS 1000-4,999 kW, Large Use and USL using 2004-2018 historical data. Toronto Hydro does not believe this methodology produces a reasonable forecast for these classes, as a linear trend over the indicated period does not reflect the most recent data.

Table 1: Customer Forecast Based on 2004-2018 Data

Rate Class	2019	2020	2021	2022	2023	2024
GS 1000-4999 kW	427	420	413	407	400	394
Large Use	38	38	38	37	37	36
USL	802	755	709	662	616	569

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 75:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 4-6;**
3-VECC-18

Please update 3-VECC-18 - Appendix A to include the 2018 actual values by month for each class up to the most recent month available.

RESPONSE:

Please see Appendix A to this interrogatory response, which includes 2018 actual values and historical data back to May 2002.

U-VECC-75 Appendix A

Date	Residential Historic	CSMUR Historic	GS<50 Historic	50-1000 kW Historic	1000-4999 kW Historic	Large Use Historic	Street Lighting Devices Historic	Scattered Load Connections Historic	Scattered Load Customers Historic
May-02	584,657		67,062	10,596	486	46			
Jun-02	584,553		67,120	10,604	487	46			
Jul-02	583,094		66,908	10,576	484	46			
Aug-02	583,832		66,827	10,586	480	46			
Sep-02	584,677		66,826	10,619	482	46			
Oct-02	585,527		66,859	10,669	485	46			
Nov-02	586,027		66,838	10,680	485	46			
Dec-02	586,714		66,934	10,708	486	46			
Jan-03	587,234		66,987	10,732	487	46		13,358	1,516
Feb-03	588,021		67,139	10,786	487	46		11,643	1,371
Mar-03	588,436		67,113	10,794	485	46		14,561	1,520
Apr-03	588,797		67,040	10,809	487	46		13,359	1,471
May-03	588,927		67,126	10,828	491	46		13,861	1,523
Jun-03	589,308		66,958	10,845	489	46		13,370	1,470
Jul-03	589,431		67,046	10,848	492	46		13,814	1,515
Aug-03	589,695		67,040	10,850	491	46		16,289	1,506
Sep-03	589,243		66,964	10,851	492	46		12,910	1,471
Oct-03	589,569		67,018	10,892	493	46		13,391	1,521
Nov-03	589,645		66,892	10,874	496	46		12,946	1,471
Dec-03	590,109		67,064	10,908	497	47		13,094	1,508
Jan-04	590,973		66,973	10,939	497	47		13,486	1,559
Feb-04	591,378		67,046	10,971	497	47		13,069	1,475
Mar-04	591,576		67,001	10,986	499	47		13,981	1,562
Apr-04	591,585		66,920	11,007	498	47		13,322	1,502
May-04	591,293		66,875	11,018	498	47		14,141	1,567
Jun-04	591,523		66,789	11,038	494	47		13,860	1,541
Jul-04	591,374		66,753	11,045	495	47		14,123	1,604
Aug-04	590,996		66,715	11,076	494	47		14,243	1,600
Sep-04	590,899		66,658	11,104	494	47		13,708	1,526
Oct-04	590,303		66,496	11,097	495	47		14,385	1,709
Nov-04	591,275		66,585	11,119	498	47		14,467	1,509
Dec-04	594,976		66,505	11,146	498	47		14,450	1,557
Jan-05	592,297		66,464	11,167	501	47		13,831	1,455
Feb-05	593,094		66,628	11,184	501	47		14,170	1,219
Mar-05	593,950		66,630	11,198	504	47		12,856	1,835
Apr-05	599,920		66,556	11,426	523	48		13,906	1,671
May-05	593,982		66,482	11,185	506	47		13,660	1,771
Jun-05	594,499		66,668	11,214	507	47		9,167	1,296
Jul-05	594,652		66,741	11,233	507	47		18,315	1,436
Aug-05	594,858		66,807	11,242	509	47		13,882	1,093
Sep-05	595,630		66,885	11,255	510	47		13,708	1,592
Oct-05	595,500		66,923	11,267	514	47		20,306	1,116
Nov-05	596,783		67,066	11,286	515	47		20,733	1,410
Dec-05	597,469		67,147	11,498	517	47		20,676	1,475
Jan-06	597,795		67,209	11,349	519	47		20,944	1,447
Feb-06	598,290		67,183	11,358	504	46		18,869	1,314
Mar-06	598,190		67,145	11,358	517	47		20,196	1,449
Apr-06	597,720		67,108	11,375	519	47		20,470	1,446
May-06	597,691		67,030	11,377	512	46		21,137	1,476
Jun-06	597,435		67,004	11,397	521	48		19,811	1,240
Jul-06	597,281		67,009	11,389	520	48		20,407	1,250
Aug-06	597,724		67,089	11,417	522	49		19,776	1,108
Sep-06	597,887		67,095	11,430	519	49		19,744	1,100
Oct-06	598,144		67,051	11,441	521	49		20,452	1,155
Nov-06	598,636		67,068	11,426	515	49		19,682	1,124
Dec-06	599,041	39	67,017	11,444	516	49		20,369	1,143

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Date	Residential Historic	CSMUR Historic	GS<50 Historic	50-1000 kW Historic	1000-4999 kW Historic	Large Use Historic	Street Lighting Devices Historic	Scattered Load Connections Historic	Scattered Load Customers Historic
Jan-07	598,696	406	66,920	11,426	509	49	159,861	20,345	1,153
Feb-07	599,570	422	66,923	11,452	519	49	161,844	18,263	1,030
Mar-07	600,370	434	66,853	11,502	517	48	161,844	20,317	1,141
Apr-07	600,116	476	66,814	11,476	517	49	161,876	19,717	1,122
May-07	599,807	504	66,682	11,469	508	48	161,876	20,326	1,146
Jun-07	599,298	504	66,617	11,440	517	49	161,876	19,335	902
Jul-07	598,760	504	66,486	11,497	515	49	161,889	21,063	1,160
Aug-07	598,575	503	66,386	11,537	519	49	161,946	20,666	1,161
Sep-07	598,402	643	66,288	11,556	519	49	161,959	21,317	1,126
Oct-07	598,352	1,052	66,199	11,550	518	49	161,963	22,097	1,160
Nov-07	598,909	1,435	66,143	11,586	519	49	161,967	21,401	1,126
Dec-07	599,867	1,648	66,245	11,590	513	49	161,968	22,131	1,150
Jan-08	600,778	1,650	66,054	11,754	517	49	161,998	22,115	1,155
Feb-08	601,489	1,694	66,150	11,863	518	48	162,007	20,647	1,080
Mar-08	601,621	1,737	66,093	11,929	519	48	162,024	22,148	1,156
Apr-08	601,637	1,832	66,152	11,977	519	48	162,031	21,457	1,120
May-08	601,983	1,926	66,094	12,016	520	49	162,040	22,189	1,164
Jun-08	602,075	2,007	66,311	12,066	520	49	162,120	21,371	1,115
Jul-08	601,908	2,246	66,286	12,063	517	49	162,155	22,135	1,161
Aug-08	602,057	2,442	66,226	12,077	518	49	162,210	22,094	1,156
Sep-08	602,306	2,701	66,293	12,105	517	48	162,212	21,314	982
Oct-08	602,576	2,816	65,867	12,095	516	48	162,215	22,123	1,164
Nov-08	602,114	3,287	66,084	12,128	517	47	162,218	21,440	1,098
Dec-08	601,806	3,703	65,917	12,156	515	47	162,219	22,071	1,138
Jan-09	601,647	4,351	65,700	12,147	516	47	162,219	22,102	1,134
Feb-09	602,022	5,117	66,133	12,181	516	47	162,219	20,162	1,016
Mar-09	602,423	5,382	66,140	12,189	514	47	162,219	22,048	1,143
Apr-09	602,792	5,455	65,846	12,163	514	47	162,219	21,394	1,098
May-09	603,186	5,766	65,798	12,208	515	47	162,219	21,857	1,122
Jun-09	603,560	5,879	66,074	12,231	515	47	162,219	21,286	1,093
Jul-09	603,489	6,287	65,854	12,287	511	47	162,324	22,392	1,150
Aug-09	603,447	6,399	66,047	12,295	510	47	162,324	21,603	1,109
Sep-09	603,302	6,911	66,100	12,337	510	47	162,371	21,364	1,097
Oct-09	603,331	7,088	65,873	12,316	506	47	162,371	20,927	1,102
Nov-09	603,533	7,288	65,835	12,384	502	47	162,472	20,362	1,072
Dec-09	603,607	7,750	65,883	12,444	509	47	162,476	14,771	1,131
Jan-10	603,694	8,970	65,607	12,597	507	47	162,509	15,647	1,128
Feb-10	604,996	9,387	66,056	12,574	511	47	162,513	14,479	1,018
Mar-10	604,959	10,206	66,156	12,703	510	47	162,520	15,788	1,122
Apr-10	604,058	10,991	65,995	12,826	510	47	162,640	15,021	1,087
May-10	603,691	11,760	65,681	12,829	511	47	162,713	15,185	1,120
Jun-10	603,665	12,729	65,799	12,873	509	47	162,964	12,159	1,107
Jul-10	604,151	13,635	66,029	12,906	509	46	162,969	12,569	1,113
Aug-10	603,134	14,352	65,895	12,916	507	46	162,985	12,377	1,124
Sep-10	602,557	15,242	65,794	12,978	506	46	162,988	11,724	1,092
Oct-10	602,703	15,560	66,041	12,980	505	46	163,001	12,576	1,125
Nov-10	603,073	15,939	65,976	13,021	504	46	163,007	12,151	1,134
Dec-10	604,121	16,380	66,167	13,168	500	50	163,014	12,539	1,113
Jan-11	605,061	16,692	65,996	13,266	498	50	163,022	12,333	1,193
Feb-11	605,857	17,004	65,942	13,314	498	50	163,019	11,133	1,068
Mar-11	606,278	17,359	65,945	13,246	501	50	163,033	11,881	1,109
Apr-11	605,031	18,323	65,856	12,938	503	50	163,047	11,386	1,087
May-11	603,400	19,876	66,224	12,795	503	50	163,067	12,252	1,096
Jun-11	603,896	20,753	66,681	12,845	503	50	163,071	12,499	1,028
Jul-11	603,612	21,315	66,723	12,824	503	50	163,092	12,512	903
Aug-11	603,858	22,423	66,900	12,824	499	50	163,095	12,515	912
Sep-11	603,770	23,132	67,017	12,791	498	51	163,096	12,511	885
Oct-11	603,414	24,046	67,050	12,701	495	51	163,097	12,320	900
Nov-11	603,800	24,462	67,175	12,562	496	51	163,103	12,269	872
Dec-11	603,819	25,230	67,261	12,587	498	52	163,117	12,245	897

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Date	Residential Historic	CSMUR Historic	GS<50 Historic	50-1000 kW Historic	1000-4999 kW Historic	Large Use Historic	Street Lighting Devices Historic	Scattered Load Connections Historic	Scattered Load Customers Historic
Jan-12	604,189	25,787	67,460	12,357	497	52	163,128	12,228	896
Feb-12	603,857	26,615	67,536	12,195	498	51	163,139	11,720	834
Mar-12	603,465	27,317	67,538	12,125	498	51	163,166	11,711	899
Apr-12	603,052	27,843	67,538	12,037	497	52	163,190	11,703	869
May-12	603,834	28,128	67,506	12,116	497	52	163,210	11,696	897
Jun-12	603,644	28,503	67,401	12,129	496	52	163,210	11,697	868
Jul-12	604,573	28,910	67,410	12,159	496	52	163,224	11,679	897
Aug-12	604,163	29,715	67,513	12,175	495	52	163,225	11,703	894
Sep-12	605,280	30,187	67,661	12,183	495	52	163,226	11,768	864
Oct-12	606,087	30,491	67,903	12,184	494	52	163,226	11,713	891
Nov-12	606,133	31,331	67,986	12,205	497	52	163,265	11,709	861
Dec-12	605,815	32,095	67,970	12,225	504	52	163,265	11,712	890
Jan-13	606,091	32,806	67,994	12,259	508	53	163,287	11,728	884
Feb-13	606,422	33,407	68,018	12,262	507	53	163,364	11,714	799
Mar-13	605,599	34,810	68,091	12,206	510	53	163,376	11,794	882
Apr-13	606,232	35,038	68,106	12,199	511	53	163,377	11,771	847
May-13	605,972	35,811	68,117	12,074	512	53	163,380	11,778	873
Jun-13	606,350	36,156	68,312	11,885	516	52	163,426	11,784	873
Jul-13	606,559	36,777	68,405	11,924	516	51	163,450	11,774	870
Aug-13	606,817	37,407	68,481	11,913	517	51	163,458	11,745	867
Sep-13	607,376	37,871	68,566	11,923	517	51	163,492	11,719	836
Oct-13	608,372	38,174	68,661	11,890	519	51	163,505	11,705	863
Nov-13	609,147	38,253	68,692	11,904	521	51	163,689	11,760	895
Dec-13	609,778	38,602	68,702	11,914	521	51	163,689	11,707	898
Jan-14	610,338	39,542	68,728	11,904	520	51	163,810	11,720	898
Feb-14	610,539	40,438	68,683	11,913	516	52	163,810	11,713	898
Mar-14	610,446	41,224	68,753	11,970	436	50	163,810	11,707	895
Apr-14	610,519	42,022	68,840	11,931	442	45	163,810	11,699	893
May-14	610,224	42,409	68,976	11,886	446	48	163,810	11,701	890
Jun-14	609,928	43,022	69,078	11,852	447	47	163,810	11,754	888
Jul-14	609,803	43,554	69,186	11,767	447	46	163,923	11,761	889
Aug-14	609,363	44,190	69,132	11,779	447	46	163,923	11,729	877
Sep-14	609,499	44,785	70,029	10,845	446	45	163,923	11,772	874
Oct-14	609,999	45,725	70,330	10,622	440	46	163,946	11,882	873
Nov-14	610,227	46,681	70,329	10,632	446	43	163,954	11,935	872
Dec-14	610,617	47,754	70,496	10,537	448	43	163,968	11,938	871
Jan-15	611,127	48,980	70,531	10,502	446	44	164,000	11,995	869
Feb-15	611,348	49,914	70,501	10,492	446	44	164,000	11,991	869
Mar-15	611,362	50,816	70,543	10,478	444	44	164,001	11,966	868
Apr-15	611,223	51,933	70,531	10,435	441	44	164,001	11,946	867
May-15	610,995	53,094	70,595	10,380	440	44	164,001	11,934	866
Jun-15	610,961	54,516	70,628	10,364	432	44	164,008	11,942	866
Jul-15	610,575	57,061	70,595	10,368	434	44	164,008	11,957	866
Aug-15	610,268	58,994	70,536	10,376	434	44	164,008	11,943	865
Sep-15	610,311	60,600	70,543	10,388	436	44	164,009	11,943	866
Oct-15	610,758	61,353	70,565	10,425	438	44	164,009	11,941	865
Nov-15	611,167	62,050	70,586	10,446	440	44	164,045	11,955	864
Dec-15	611,554	62,647	70,576	10,475	441	44	164,045	11,936	865
Jan-16	612,055	63,370	70,577	10,496	442	44	164,081	11,936	865
Feb-16	612,347	63,732	70,570	10,510	442	44	164,146	11,983	867
Mar-16	611,533	64,294	70,533	10,510	443	44	164,163	12,024	867
Apr-16	611,584	64,680	70,531	10,508	444	44	164,168	12,038	867
May-16	611,309	64,917	70,517	10,502	443	44	164,281	12,056	867
Jun-16	611,021	65,685	70,499	10,475	443	42	164,296	12,056	866
Jul-16	610,430	65,758	70,566	10,359	441	44	164,332	12,051	866
Aug-16	610,265	66,456	70,544	10,310	431	44	164,369	12,079	867
Sep-16	610,423	66,796	70,527	10,318	431	44	164,383	12,090	867
Oct-16	610,575	67,351	70,508	10,333	431	44	164,389	12,084	867
Nov-16	611,012	67,985	70,497	10,343	430	44	164,403	12,102	865
Dec-16	611,245	68,472	70,539	10,352	430	44	164,419	12,148	865

U-VECC-75 Appendix A

	Residential	CSMUR	GS<50	50-1000 kW	1000-4999 kW	Large Use	Street Lighting Devices	Scattered Load Connections	Scattered Load Customers
Date	**Historic**	**Historic**	**Historic**	**Historic**	**Historic**	**Historic**	**Historic**	**Historic**	**Historic**
Jan-17	611,636	69,066	70,495	10,364	429	44	164,485	12,199	865
Feb-17	611,857	69,376	70,529	10,386	429	44	164,496	12,197	864
Mar-17	611,974	69,954	70,899	10,370	430	44	164,506	12,206	861
Apr-17	611,830	70,312	71,111	10,399	431	44	164,518	12,201	861
May-17	611,846	70,637	71,074	10,448	429	44	164,537	12,205	860
Jun-17	611,660	71,041	71,116	10,407	431	44	164,537	12,196	860
Jul-17	611,153	71,093	71,140	10,413	430	44	164,545	12,194	859
Aug-17	611,011	71,591	71,163	10,418	430	44	164,550	12,191	859
Sep-17	611,147	71,834	71,187	10,424	430	43	164,551	12,171	859
Oct-17	611,277	72,231	71,211	10,430	430	44	164,552	12,237	857
Nov-17	611,652	72,683	71,235	10,436	430	44	164,587	12,260	858
Dec-17	611,852	73,031	71,258	10,441	430	44	164,622	12,272	857
Jan-18	612,188	73,455	71,282	10,447	430	44	164,636	12,274	854
Feb-18	612,188	73,465	71,284	10,463	430	44	164,640	12,265	852
Mar-18	612,032	73,919	71,279	10,489	430	44	164,655	12,274	849
Apr-18	612,305	74,037	71,275	10,486	429	44	164,659	12,270	848
May-18	612,223	74,081	71,285	10,463	432	44	164,661	12,257	841
Jun-18	612,169	74,523	71,170	10,515	432	44	164,662	12,245	837
Jul-18	611,976	75,000	71,216	10,530	422	44	164,662	12,237	835
Aug-18	612,075	75,635	71,176	10,506	422	38	164,667	12,225	835
Sep-18	611,987	76,188	71,223	10,422	420	38	164,667	12,198	833
Oct-18	612,479	76,449	71,250	10,419	424	38	164,668	12,187	832
Nov-18	612,768	76,776	71,348	10,439	425	38	164,698	12,186	826
Dec-18	612,754	76,806	71,400	10,462	430	38	164,698	12,180	825

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 76:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 4-6;**
Technical Conference Transcript, Day 4, pages 113-115

At the Technical Conference THESL indicated that it would be providing, as part of the Update, the linear trend models used to forecast the customer counts for each class. Exhibit U describes the models but does not provide the actual linear trend models. Please provide.

RESPONSE:

Table 1 below outlines model equations for rate classes where a linear trend model was used. The trend line is applied to the last actual value.

Table 1: Customer Forecast Models

Rate Class	Linear trend models	Data Period Used
Residential	y = 131.32x + 589366	May 2002-Dec 2018
GS <50 kW	y = 11.059x + 70125	Sep 2014-Dec 2018
GS 50-999 kW	y = -2.4925x + 11683	May 2002-Dec 2018
Street Lighting	y = 21.747x + 161800	Feb 2007-Dec 2018

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 77:

Reference(s): **Exhibit U, Tab 3, Schedule 1, p. 2;**
3-VECC-21;
Technical Conference Transcript, Day 4, p. 111

a) At the Technical Conference, THESL was uncertain as to the extent to which it would be “updating” its load forecast models. For purposes of the Update did THESL: i) re-valuate each of its load forecast models (per VECC 21 a)) in terms of what were the appropriate explanatory variables to use, including the testing of variables not used in the original models or ii) simply re-estimate the models using the same variables as in the original models?

b) Please provide a schedule that sets out the “weather normal” HDD and CDD values as used in the original load forecast and those used in the Update.

c) Please provide a schedule that sets out the historical and forecast unemployment rates and GDP values as used in the original load forecast and the Update.

RESPONSE:

a) Toronto Hydro revaluated all models for the Load Forecast update using up-to-date information. Different input variables were retested to determine the best fit based on statistics and professional evaluation. As noted in Exhibit U, Tab 3, Schedule 1, page 2, lines 13-17, all model specifications remained unchanged except for the GS

1000-4999 kW class, where the unemployment rate variable was dropped.

b) The historical and forecast values for all driver variables, including HDD, CDD, unemployment and GDP, as appropriate, are provided in Appendix F of Exhibit U, Tab 3, Schedule 1, for both the original and updated load forecasts.

c) See part b.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 78:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 2-3;**
Exhibit U, Tab 3, Schedule 1, Appendix B and Appendix D

a) Are the 2018-2020 planned CDM results (per Appendix B) comparable (in terms of definition) to the values set out in Appendix D, Tables 1-7?
   i) If yes, please reconcile the savings values shown in Table 7 for program years 2019 and 2020 with the total savings shown in Appendix B for the same years
   ii) If no, please provide a schedule that reconciles the savings values shown in Table 7 for program years 2019 and 2020 with the total savings shown in Appendix B for the same years and that explains the sources of the differences.

b) What is the source/basis for the non-verified 2018 CDM results?

c) Please provide a schedule that compares by customer class the non-verified 2018 CDM results (per Appendix D, Tables 1-6) with the 2018 planned results as set out in the THESL's latest CDM Plan (Appendix B). In doing so, please adjust the results as set out in the CDM Plan (as required) so that they are comparable, in terms of definition, with the unverified CDM results as shown in Tables 1-6 of Appendix D and explain the basis/reasons for the adjustments.

d) How does THESL deliver each of the CDM programs set out in its CDM plan – as submitted to the IESO (i.e., does it use third party contractors and/or other contracts with third parties)?

e) With respect to the 2019-2020 CDM programs set out in Appendix B, please indicate which ones THESL already has third-party contracts in place to deliver and outline whether or not there are any penalties for terminating the contracts.

RESPONSE:

a)

i) The 2018-2020 planned CDM results (per Appendix B) are not comparable to the values set out in Appendix D, Tables 1-7 because the values provided by the IESO in the originally filed Appendix B as part of the Application Update were incorrect. Please refer to a corrected version of Exhibit U, Tab 3, Schedule 1, Appendix B, appended to this response. The corrected Appendix B is the source of the 2018-2020 data for Appendix D.

ii) Please refer to Table 1 for a reconciliation between the savings values in Table 7 and the update to Appendix B.

Table 1: Reconciliation between the savings values shown in Table 7 for program years 2019 and 2020 and the total savings in Appendix B

	CDM Load Forecast (MWh) (Appendix D)	Persistence Removed (MWh)	CDM Load Forecast (Persistence from Previous Years Removed)	Net-to-Gross Ratios	CDM Planned Savings (Net MWh) (Appendix B)
2019	1,034,023	726,232	307,791	88%	269,609
2020	1,483,703	1,046,450	437,253	87%	381,414

b) Toronto Hydro tracks all project completions and savings results per program and uses them as the basis for the estimated 2018 savings. This includes adjustments for net to gross ratios based on historical values.

c) Please refer to Table 2 for a schedule that compares the non-verified 2018 CDM results (Appendix D) with the total savings in the corrected Appendix B.

Table 2: Comparison between the non-verified 2018 CDM results (per Appendix D, Tables 1-6) with the total savings in Appendix B

	CDM Load Forecast (MWh) (Appendix D)	Persistence Removed (MWh)	CDM Load Forecast (Persistence from Previous Years Removed)	Net-to-Gross Ratios	CDM Planned Savings (Net MWh) (Appendix B)
Residential	201,939	149,145	52,794	115%	60,912
CSMUR	8,898	6,410	2,488	120%	2,982
GS<50 kW	56,196	17,945	38,251	91%	34,773
GS50 -999 kW	302,606	146,150	156,456	86%	134,818
GS1,000 – 4,999 kW	100,405	39,247	61,158	84%	51,524
LU	56,187	23,554	32,633	84%	27,513
Total	**726,232**	**382,450**	**343,782**	**91%**	**312,521**

d) Toronto Hydro delivers all of the programs noted in its CDM plan while using third parties to support varying portions of the work depending on the requirements of the program and to supplement the skill of the Toronto Hydro CDM team. For example, for direct install programs Toronto Hydro contracts the installation of the work to a contractor due to the specialized work involved.

e) In accordance with the OEB rules requiring accounting separation between CDM costs and rate regulated distribution costs, Toronto Hydro ratepayers are insulated from any costs or penalties associated with CDM contract termination that are not recovered from the IESO.

Toronto Hydro-Hydro Electric System Limited
EB-2018-0165
Interrogatory Responses
U-VECC-78
Appendix A
FILED: June 11, 2019
(2 pages)

Toronto Hydro-Hydro Electric System Limited
EB-2018-0165
Exhibit U
Tab 3
Schedule 1
Appendix B
UPDATED: June 11, 2019
(2 pages)

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (including	Agriculture	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	SAVE ON ENERGY AUDIT FUNDING PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$101,902	251	$589,927	2,063	$1,407,090	9,604	$843,810	10,627	$807,212	10,000	$515,146	5,000	$4,265,087	37,545
	SAVE ON ENERGY BUSINESS REFRIGERATION INCENTIVE PROGRAM			01-Sep-2016			Yes	Yes		Yes		$0	0	$0	0	$974,837	3,481	$2,002,425	8,695	$1,333,283	4,986	$1,325,886	4,945	$5,636,430	21,729
	SAVE ON ENERGY COUPON PROGRAM			01-Jul-2015	Yes	Yes						$2,198,647	15,589	$6,325,639	84,732	$16,876,770	154,798	$11,246,773	57,485	$2,319,530	10,000	$1,211,169	4,104	$40,178,528	277,560
	SAVE ON ENERGY ENERGY MANAGER PROGRAM			01-Jul-2015						Yes	Yes	$13,666	0	$710,398	15,534	$1,975,785	6,776	$2,366,450	3,941	$2,409,850	4,022	$2,164,050	3,561	$9,640,199	29,665
	Save on Energy Energy Performance Program for Multi-Site Customers			01-Jan-2015				Yes		Yes	Yes	$0	0	$0	0	$0	1,725	$194,000	0	$194,000	0	$194,000	0	$582,000	1,725
	SAVE ON ENERGY EXISTING BUILDING COMMISSIONING PROGRAM			01-Feb-2016				Yes		Yes	Yes	$0	0	$539,587	730	$374,486	788	$239,661	1,910	$106,086	0	$109,269	0	$1,369,089	3,428
	SAVE ON ENERGY HEATING & COOLING PROGRAM			01-Jul-2015	Yes	Yes						$2,535,528	4,023	$4,444,112	9,408	$4,650,863	7,328	$3,901,906	4,067	$2,720,318	3,000	$2,043,949	2,163	$20,296,676	29,990
	SAVE ON ENERGY HIGH PERFORMANCE NEW CONSTRUCTION PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$122,493	77	$1,604,652	8,929	$3,797,751	2,610	$2,029,841	3,111	$2,436,056	4,000	$1,962,732	2,964	$11,953,525	21,691
	SAVE ON ENERGY HOME ASSISTANCE PROGRAM			01-Sep-2015		Yes						$2,220	283	$1,119,803	1,171	$1,094,833	774	$196,222	302	$3,249,977	5,000	$3,314,981	5,100	$8,978,036	12,605
	SAVE ON ENERGY MONITORING & TARGETING PROGRAM			01-May-2016						Yes	Yes	$0	0	$0	0	$3,995	0	$20,000	0	$20,000	0	$20,000	0	$63,995	0
	SAVE ON ENERGY NEW CONSTRUCTION PROGRAM			01-Jul-2015	Yes							$456	39	$54,294	237	$232,341	236	$441,084	491	$443,689	500	$529,859	787	$1,701,723	2,291
	SAVE ON ENERGY PROCESS & SYSTEMS UPGRADES PROGRAM			01-Jul-2015				Yes		Yes	Yes	$32,086	0	$426,596	18,831	$2,020,513	2,544	$4,571,778	18,090	$5,136,078	21,060	$30,748,416	155,790	$42,935,467	216,315
	SAVE ON ENERGY RETROFIT PROGRAM			01-Jul-2015			Yes	Yes		Yes	Yes	$3,244,135	39,246	$26,507,778	213,504	$28,216,341	146,419	$31,465,524	182,017	$31,217,416	180,000	$30,579,363	175,000	$151,230,557	936,983
	SAVE ON ENERGY SMALL BUSINESS LIGHTING PROGRAM			01-Jul-2015			Yes					$1,385	0	$166,782	69	$1,581,395	5,306	$2,465,191	8,305	$1,910,606	6,000	$1,447,998	4,077	$7,573,357	23,178
	SAVE ON ENERGY SMART THERMOSTAT PROGRAM			01-Jan-2015	Yes	Yes						$0	0	$0	0	$0	0	$441,789	0	$0	0	$0	0	$441,789	0
		ADAPTIVE THERMOSTAT LOCAL PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$26,672	0	$477,696	0	$380,388	755	$379,099	750	$384,984	750	$1,648,838	750
		DATA CENTRE PILOT		14-Jul-2016								$0	0	$0	0	$0	0	$0	0	$0	0	$0	0	$0	0
		DIRECT INSTALL - HYDRONIC PILOT		01-Jul-2015								$0	668	$0	0	$0	0	$0	0	$0	0	$0	0	$0	668
		DIRECT INSTALL - RTU CONTROLS PILOT		01-Jul-2015		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	370	$0	0	$0	0	$0	0	$0	0	$0	370
		ELECTRONICS TAKEBACK PILOT PROGRAM		15-Apr-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	1,145	$0	0	$0	0	$0	0	$0	0	$0	1,145
		HOME DEPOT HOME APPLIANCE MARKET UPLIFT CONSERVATION FUND PILOT PROGRAM		01-Jan-2015	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	9	$0	0	$0	0	$0	0	$0	0	$0	9
		MURB In-Suite Direct Install Lighting Program		01-Jan-2018								$0	0	$0	0	$0	0	$1,142,587	430	$2,711,299	6,000	$2,722,220	6,000	$6,576,106	12,430
		OPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$0	2,864	$191,927	0	$502,285	1,459	$662,347	6,541	$633,130	5,422	$1,989,688	16,287
		PUMPSAVER 2.0		01-Sep-2016								$0	0	$0	0	$0	0	$1,846,013	6,762	$1,273,427	4,000	$871,519	2,000	$3,990,959	29,319
		PUMPSAVER LOCAL PROGRAM		01-Sep-2016								$0	0	$100,075	988	$2,112,372	15,569	$0	0	$0	0	$0	0	$2,212,447	0
		RTUSAVER		01-Jan-2017		Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$69,316		$2,068,149	3,297	$1,903,332	3,000	$1,903,332	3,000	$5,944,129	9,297
		SOCIAL BENCHMARKING LOCAL PROGRAM		01-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$4,078,842	10,476	$2,586,817	0	$2,586,817	0	$2,586,817	0	$11,839,293	10,476
		SWIMMING POOL EFFICIENCY LOCAL PROGRAM		01-Apr-2017	Yes							$0	0	$0	0	$271,149	1,402	$419,626	778	$411,598	750	$411,598	750	$1,513,971	3,680
		TRUCKLOAD EVENT PILOT PROGRAM		01-Sep-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	3,296	$498,428	0	$0	0	$0	0	$0	0	$498,428	3,296
		Toronto Hydro – Enbridge Joint Low-Income Program LDC Innovation Fund Pilot Program		30-Jan-2017		Yes						$0	0	$0	0	$0	373	$0	0	$0	0	$0	0	$0	373
		WHOLE HOME PILOT		30-Jan-2017	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	0	$0	0	$0	1,132	$51,600	0	$51,600	0	$51,600	0	$154,800	1,132
		EnerNOC Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	199	$0	0	$0	0	$0	0	$0	0	$0	0	$0	0
		Loblaw P4P Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	2,469	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	2,469
		Strategic Energy Group Conservation Fund Pilot Program		01-Jan-2015				Yes		Yes	Yes	$0	2,577	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0
FCR TOTAL												**8,252,518**	**65,421**	**42,616,315**	**363,882**	**70,906,730**	**371,342**	**71,423,919**	**312,521**	**64,283,619**	**269,609**	**85,732,016**	**381,414**	**343,215,117**	**1,706,407**
Pay for Performance Programs																								$0	
P4P TOTAL												**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0.0**	**$0**	**0**

CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	CDM-000409

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program						
					Residential	Low-income	Small business	Commercial (including	Agriculture	Institutional	Industrial
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) ***(Not funded through 2015-2020 CDM Framework)***	Appliance Retirement Initiative										
	Coupon Initiative										
	Bi-Annual Retailer Event Initiative										
	HVAC Incentives Initiative										
	Residential New Construction and Major Renovation Initiative										
	Energy Audit Initiative										
	Efficiency: Equipment Replacement Incentive Initiative										
	Direct Install Lighting and Water Heating Initiative										
	New Construction and Major Renovation Initiative										
	Existing Building Commissioning Incentive Initiative										
	Process and Systems Upgrades Initiatives - Project Incentive Initiative										
	Process and Systems Upgrades Initiatives - Energy Manager Initiative										
	Low Income Initiative										
	Program Enabled Savings										

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Program	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Appliance Retirement Initiative		316												**0**
Coupon Initiative		2,536												**2,516**
Bi-Annual Retailer Event Initiative		4,243												**4,097**
HVAC Incentives Initiative		3,399												**3,399**
Residential New Construction and Major Renovation Initiative		0												**0**
Energy Audit Initiative		7,005												**7,005**
Efficiency: Equipment Replacement Incentive Initiative		160,765												**160,879**
Direct Install Lighting and Water Heating Initiative		6,891												**7,189**
New Construction and Major Renovation Initiative		25,472												**25,461**
Existing Building Commissioning Incentive Initiative		522												**243**
Process and Systems Upgrades Initiatives - Project Incentive Initiative		5,327												**5,327**
Process and Systems Upgrades Initiatives - Energy Manager Initiative		8,403												**5,013**
Low Income Initiative		1,680												**1,248**
Program Enabled Savings		311												**311**
2011-2014 CDM Framework (and 2015 extension) TOTAL	**$0**	**226,869**											**0.0**	**222,687**
TARGET GAP TOTAL													**$0**	
CDM PLAN TOTAL	**$8,252,518**	**292,289.6**	**$42,616,315**	**363,881.9**	**$70,906,730**	**371,341.9**	**$71,423,919**	**312,521.1**	**$64,283,619**	**269,609.3**	**$85,732,016**	**381,414.5**	**$343,215,117**	**1,929,095**
MINIMUM ANNUAL SAVINGS CHECK		**True**		**True**		**True**		**True**		**True**		**True**		

Option
Yes
No

Program Types
Regional
Local
Provincial

2011-2014 Province Wide Programs
Aboriginal Program
Audit Funding
Bi-Annual Retailer Event
Conservation Instant Coupon Booklet
Direct Install Lighting
Energy Manager (PSUI)
Existing Building Commissioning
Heating and Cooling Initiative
High Performance New Construction
Low Income Home Assistance Program
Monitoring and Targeting (PSUI)
Other
peaksaverPLUS
Process and Systems Upgrades Program
Program Enabled Savings
Residential New Construction
Retrofit Initiative

2015-2020 CDM Programs
Audit Funding Program
Energy Manager Program
Existing Building Commissioning
High Performance New Construction
Home Assistance Program
Process and Systems Upgrades Program
Monitoring and Targeting Program
Coupon Program
New Construction Program
Heating and Cooling Program
Retrofit
Small Business Lighting
Whole Home Pilot Program

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 79:

Reference(s): Exhibit U, Tab 3, Schedule 1, pp. 2-3;
Exhibit U, Tab 3, Schedule 1, Appendix C and Appendix D

a) With respect to Appendix C, Table 2, please add rows that indicate the Cumulative Annual Gross CDM savings from 2006-2016 programs in each of the years 2017-2024.

b) With respect to Appendix C, Table 3, please add rows that reconcile the total values reported for each year 2017-2024 in the response to part (a) with the values for 2017-2024 are reported in Appendix C, Table 1.

c) Please confirm that, for each customer class, the values reported in part (a) for the years 2017-2024 are equal to the values reported for 2006-2016 in Appendix D, Tables 9-15. If not confirmed, please explain why.

RESPONSE:

a) Please see Table 1.

Table 1: Cumulative Annual Gross CDM Savings (MWh)

Year	Residential	CSMUR	GS<50 kW	GS50 – 999 kW	GS1,000 – 4,999 kW	LU	Total
2006	23,311	0	0	0	0	0	**23,311**
2007	103,758	0	15,342	16,418	15,360	15,176	**166,054**
2008	235,152	0	68,853	72,194	70,403	69,562	**516,164**
2009	278,982	82	99,383	103,820	108,691	118,935	**709,892**
2010	337,794	339	172,007	177,242	187,203	205,179	**1,079,763**
2011	374,635	599	222,968	240,000	225,696	221,152	**1,285,051**
2012	412,941	913	279,602	329,834	262,093	250,368	**1,535,750**
2013	431,024	967	324,436	407,657	280,159	261,249	**1,705,493**
2014	457,816	1,225	369,622	502,026	324,608	283,352	**1,938,649**
2015	497,648	1,931	412,922	653,204	425,570	353,433	**2,344,707**
2016	555,301	4,081	435,450	811,045	525,668	420,890	**2,752,435**
2017	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2018	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2019	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2020	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2021	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2022	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2023	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**
2024	593,313	5,682	443,161	881,384	572,936	444,020	**2,940,497**

b) Please see Table 2 below for the updated Table 3: Reconciliation of CDM Verified Results and Cumulative CDM Savings Used in Load Forecast. 2015 and 2016 persistent savings were not revised in the update to 3-VECC-25. Please refer to a corrected version of Exhibit U, Tab 3, Schedule 1, Appendix C, appended to this response. The revised persistent savings for those years are shown in the corrected Appendix C.

Table 2: Reconciliation of CDM Verified Results and Cumulative CDM Savings Used in Load Forecast (MWh)

Year	CDM Verified Results	Persistence Variance	Realization Rates Variance	Line Loss Variance	CDM in Load Forecast Appendix A-1
2006	56,010	0	-33,367	668	23,311
2007	381,928	0	-220,454	4,580	166,054
2008	492,314	88,040	-78,164	13,973	516,164
2009	686,443	101,199	-96,695	18,945	709,892
2010	1,028,306	151,343	-128,417	28,530	1,079,763
2011	1,282,183	151,350	-182,707	34,225	1,285,051
2012	1,236,660	344,677	-86,653	41,066	1,535,750
2013	1,410,555	355,618	-106,482	45,802	1,705,493
2014	1,671,655	395,250	-180,480	52,223	1,938,649
2015	1,936,239	534,933	-189,500	63,036	2,344,707
2016	2,199,818	661,635	-182,944	73,927	2,752,435
2017	2,037,727	823,726	0	79,044	2,940,497
2018	1,951,115	910,338	0	79,044	2,940,497
2019	1,804,198	1,057,255	0	79,044	2,940,497
2020	1,684,035	1,177,418	0	79,044	2,940,497
2021	1,582,947	1,278,506	0	79,044	2,940,497
2022	1,542,040	1,319,413	0	79,044	2,940,497
2023	1,469,789	1,391,664	0	79,044	2,940,497
2024	1,134,031	1,727,422	0	79,044	2,940,497

c) Toronto Hydro confirms that the values reported in part (a) for the years 2017-2024 are equal to the values reported for 2006-2016 in Appendix D, Tables 9-15.

UPDATE TO 3-VECC-25

Table 1: Verified Gross CDM Savings per IESO/OPA Reports

Program Year	Verified Gross CDM Savings per IESO/OPA Reports (MWh) — Calendar Year 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	
2006	56,010	56,010	56,010	56,010	9,964	9,964	9,138	9,138	8,604	8,604	8,145	8,145	8,145	8,145	7,400	6,206	6,206	6,206	3,341	**341,389**	
2007	-	325,918	237,877	226,833	226,833	226,824	40,551	40,551	40,551	18,405	15,514	12,062	12,062	12,062	12,062	5,774	1,403	1,256	1,256	**1,457,795**	
2008	-	-	198,427	196,101	195,318	195,318	189,358	182,963	161,114	132,580	118,377	89,579	87,072	87,072	85,420	85,153	85,032	82,365	16,808	**2,188,058**	
2009	-	-	-	207,499	183,543	183,543	183,487	182,023	177,457	170,241	157,083	106,015	74,958	58,123	36,220	26,986	26,976	26,616	23,866	**1,824,635**	
2010	-	-	-	-	412,648	376,505	376,497	376,461	374,876	319,471	253,239	236,281	209,686	99,652	24,345	24,345	24,176	24,160	24,160	**3,156,503**	
2011	-	-	-	-	-	290,029	289,158	287,288	280,372	278,421	274,558	263,083	262,934	243,971	238,509	208,193	207,404	206,173	35,115	**3,365,210**	
2012	-	-	-	-	-	-	148,470	146,814	144,960	139,327	134,919	123,593	117,465	117,404	114,059	77,560	67,968	62,334	49,951	**1,444,823**	
2013	-	-	-	-	-	-	-	185,316	182,084	175,009	169,472	155,245	147,549	147,471	143,269	138,920	120,027	93,232	88,365	**1,745,959**	
2014	-	-	-	-	-	-	-	-	301,636	289,914	280,742	257,174	244,424	244,296	237,336	237,336	231,486	198,351	161,708	**2,684,402**	
2015	-	-	-	-	-	-	-	-	-	404,267	397,489	396,534	396,750	396,287	395,720	395,697	395,599	393,356	355,578	**3,927,277**	**/c**
2016	-	-	-	-	-	-	-	-	-	-	390,281	390,017	390,072	389,714	389,694	376,778	375,764	375,742	373,883	**3,451,943**	**/c**
	56,010	**381,928**	**492,314**	**686,443**	**1,028,306**	**1,282,183**	**1,236,660**	**1,410,555**	**1,671,655**	**1,936,239**	**2,199,818**	**2,037,727**	**1,951,115**	**1,804,198**	**1,684,035**	**1,582,947**	**1,542,040**	**1,469,789**	**1,134,031**	**25,587,994**	**/c**

Table 2: Cumulative Annual Gross CDM Savings (MWh)

Year	CUMULATIVE ANNUAL GROSS CDM SAVINGS (MWh) — Residential	CSMUR	GS<50 kW	GS50 -999 kW	GS1,000 – 4,999 kW	LU	Total
2006	23,311	0	0	0	0	0	**23,311**
2007	103,758	0	15,342	16,418	15,360	15,176	**166,054**
2008	235,152	0	68,853	72,194	70,403	69,562	**516,164**
2009	278,982	82	99,383	103,820	108,691	118,935	**709,892**
2010	337,794	339	172,007	177,242	187,203	205,179	**1,079,763**
2011	374,635	599	222,968	240,000	225,696	221,152	**1,285,051**
2012	412,941	913	279,602	329,834	262,093	250,368	**1,535,750**
2013	431,024	967	324,436	407,657	280,159	261,249	**1,705,493**
2014	457,816	1,225	369,622	502,026	324,608	283,352	**1,938,649**
2015	497,648	1,931	412,922	653,204	425,570	353,433	**2,344,707**
2016	555,301	4,081	435,450	811,045	525,668	420,890	**2,752,435**

Table 3: Reconciliation of CDM Verified Results and Cumulative CDM Savings Used in Load Forecast

Year	CDM Verified Results	Persistence Variance	Realization Rates Variance	Line Loss Variance	CDM in Load Forecast Appendix A-1
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2006	56,010	0	-33,367	668	23,311
2007	381,928	0	-220,454	4,580	166,054
2008	492,314	88,040	-78,164	13,973	516,164
2009	686,443	101,199	-96,695	18,945	709,892
2010	1,028,306	151,343	-128,417	28,530	1,079,763
2011	1,282,183	151,350	-182,707	34,225	1,285,051
2012	1,236,660	344,677	-86,653	41,066	1,535,750
2013	1,410,555	355,618	-106,482	45,802	1,705,493
2014	1,671,655	395,250	-180,480	52,223	1,938,649
2015	1,936,239	534,933	-189,500	63,036	2,344,707
2016	2,199,818	661,635	-182,944	73,927	2,752,435

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 80:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pages 2-3; Appendix C**
3-VECC-25 d)
3-VECC-28 a)

a) With respect to Appendix C, Table 1, it is noted that while the impact of 2015 programs in 2015 matches the results reported by the IESO per VECC-28 a) (i.e., 404,267 MWh); the impacts set out in Table 1 of 2015 programs in the years 2016 through 2024 do not match the IESO reported results (For example, for 2016 Table 1 shows 389,832 MWh whereas the IESO report shows 397,489 {based on initial results plus subsequent adjustments}). Please reconcile.

b) With respect to Appendix C, Table 1, it is noted that while the impact of 2016 programs in 2016 matches the results reported by the IESO per VECC-28 a) (i.e., 390,281 MWh); the impacts set out in Table 1 of 2016 programs in the years 2017 through 2024 do not match the IESO reported results base on initial results plus subsequent adjustments. Please reconcile.

c) With respect to Appendix C, Table 3, it is noted that the values in 2006-2014 for the Line Loss Variance adjustment are different than those in VECC-25 d) even though the CDM Verified Results values are the same in both references. Please explain why the value for the adjustment has changed.

RESPONSE:

a) Please refer to Toronto Hydro's response to interrogatory U-VECC-79 (b).

b) Please refer to Toronto Hydro's response to interrogatory U-VECC-79 (b).

c) The line loss variance values in 3-VECC-25 part (d) were calculated using a loss factor that was incorrectly rounded at the 4th decimal level for certain classes (CSMUR, GS<50, GS 50-1000 kW, GS1-5 MW). The updated CDM values use the correct loss factor adjustment.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 81:

Reference(s): **Exhibit U, Tab 3, Schedule 1, pp. 2-3;**
Exhibit U, Tab 3, Schedule 1, Appendices B, D & E
Technical Conference Transcript, pp. 117-118, 3-VECC-29 (d)

a) Please confirm that the difference between the Load Forecast Energy Impacts values set out in Appendix D and the totals for Gross Annual CDM savings set out in Appendix D (Tables 9-15) is that the values in Appendix C include losses whereas the values in Appendix D do not.

b) If not confirmed, please explain the basis for the differences (e.g. 2020 total in Appendix C is 4,242,251 kWh versus the 2020 total in Appendix D of 4,127,767 kWh).

c) Given that the impact of the 2018 programs is not yet verified, why are they not also included in the calculation of the LRAMVA threshold (per Appendix E)?

d) If the impact of 2020 CDM programs is based on THESL's most recent CDM Plan (Appendix B), please explain why LRAM value for 2020 programs (381,441.46 MWh per Appendix E) does not equal the planned results for 2020 programs (403,627 MWh per Appendix B).

e) With respect to Appendix E, please provide the derivation of the impact of 2019 programs on the 2020 forecast CDM (per column J). In doing so, please also reconcile the savings attributed to 2019 programs with the 2019 CDM planned savings per Appendix B.

RESPONSE:

a) Assuming the question is in reference to the Load Forecast Energy Impacts values set out in Appendix C, then Toronto Hydro confirms that the values in Appendix C include losses whereas the values in Appendix D do not.

b) Not Applicable. Please see part (a).

c) Toronto Hydro has been informed by the IESO that the IESO will not be issuing verified results for 2018 CDM savings. For this reason, and consistent with past practice prior to the IESO/OPA's involvement in verifying CDM savings, Toronto Hydro relies on its own verification of the program savings. Based on this verification, 2018 program results are not included as part of the LRAMVA calculations for the 2020-24 period.

d) The LRAM value for 2020 programs (381,414.46 MWh per Appendix E) does not equal the planned results for 2020 programs (403,627 MWh per Appendix B) because the values provided in the originally filed Appendix B as part of the Application Update were incorrect. Please refer to the corrected version of Exhibit U, Tab 3, Schedule 1, Appendix B, appended to the response to interrogatory U-VECC-78. The LRAM value for 2020 programs equals the values provided in the corrected Appendix B.

e) The impact of 2019 programs on the 2020 forecast CDM (per column J) was derived by using the 2020-2024 persistent savings from 2019 program savings. The savings persistence was calculated based on historical program savings persistence from the 2017 IESO verified results.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 82:

Reference(s): Exhibit U, Tab 3, Schedule 2, p. 1 and Appendix A

It is noted that the 2018 revenue from pole and duct rental in the Update has increased by almost $8.7 M and costs have increased by roughly $6.7 M. Please provide the reasons for the change in both revenue and costs.

RESPONSE:

The increase for pole and duct rental revenue and costs resulted from an increased demand for pole attachment accommodations in 2018. Toronto Hydro incurs make-ready costs to accommodate attachments on its poles. These non-recurring costs depend on the particular circumstances relating to the attachment (i.e. the type of attachment and field conditions), and Toronto Hydro recovers these costs from the third party requesting the pole attachment through one-time or non-recurring charges. The plan for 2019 and 2020 assumes that the demand will stabilize to historical levels.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 83:

Reference(s): **Exhibit U, Tab 3, Schedule 2, p. 2 and Appendix A;**
Exhibit 8, Tab 3, Schedule 2, p. 11
OEB Decision EB-2015-0304, February 14, 2019

a) Please confirm that neither the original Application nor the Update include the increase in Retail Service Charges approved by the Board in February 2019.

b) Please provide an updated version of Appendix 2-H that reflects the increase revenues from this decision.

RESPONSE:

a) Confirmed.

b) Please refer to Appendix A to this response for an updated version of Appendix 2-H.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
		2015	2016	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
4225	Late Payment Charges	$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
4082	Retailers' Fixed charge	$5,320	$5,280	$5,520	$5,280	$10,840	$10,840
4082	Retailers' Variable Charge	$257,269	$225,343	$178,662	$146,005	$342,772	$324,840
4082	Distributor Consolidated Billing (DCB) Charges	$143,718	$125,603	$106,118	$87,079	$198,415	$188,134
4082	Retail Consolidated Billing (RCB) Credit	-$9,072	-$8,351	-$635	$0	$0	$0
4084	Retailer Service Transaction Request	$13,764	$12,656	$10,350	$8,302	$18,563	$17,632
4084	Retailer Service Transaction Processing	$6,344	$5,722	$4,485	$3,190	$8,542	$8,162
4090/4086	SSS Admin Charge	$2,196,126	$2,317,539	$2,269,960	$2,313,558	$2,389,560	$2,407,409
4210	Parking Rental	$3,790	$1,200	$1,200	$4,408	$0	$0
4210	Property Rental	$41,516	$46,854	$53,414	$47,228	$0	$0
4215	TTC Rectification	$253,250	$303,900	$303,900	$303,900	$303,900	$303,900
4215	Settlement Discounts Taken	$404,384	$381,359	$523,847	$340,755	$389,382	$389,382
4215	Stale Dated Cheques	$453,706	$417,078	$736,416	$462,171	$533,368	$533,368
4220	Street Lighting	$7,055,723	$8,200,259	$9,229,601	$8,035,739	$8,536,375	$8,076,074
4325	Merchandise and Jobbing Revenue	$23,108,588	$32,769,384	$45,929,144	$47,400,242	$36,014,502	$37,732,615
4330	Merchandise and Jobbing Costs	-$14,047,565	-$19,805,704	-$29,913,621	-$27,406,949	-$15,651,688	-$15,991,089
4335	Gain/Loss on disposals	$211,338	$0	$0	$0	$0	$0
4375	Shared Services Recovery[1]	$2,927,027	$3,212,613	$4,829,010	$5,670,327	$5,494,615	$5,507,706
4355	Gain on Disposition of Utility and Other Property	$4,062,681	$2,132,160	$515,158	$576,205	$1,630,000	$0
4398	Foreign Exchange Gain/(Loss)	-$1,500,430	$162,383	$54,784	-$128,336	$0	$0
4405	Investment Interest Income	$1,298,537	$186,388	$9	$0	$120,000	$120,000
Specific Service Charges		$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
Late Payment Charges		$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
Other Operating Revenues		$10,825,837	$12,034,443	$13,422,839	$11,757,613	$12,731,715	$12,259,740
Other Income or Deductions		$16,060,177	$18,657,224	$21,414,483	$26,111,488	$27,607,430	$27,369,233
Total		**$37,799,149**	**$44,729,912**	**$45,720,340**	**$47,158,636**	**$49,179,335**	**$47,070,553**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Appendix 2-H
Other Operating Revenue

Account Breakdown Details

Account 4235 -Specific Service Charges

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Account Set Up Charge	$3,163,196	$3,315,852	$3,132,490	$2,686,465	$3,010,922	$3,027,508
NSF Collection Charges	$59,445	$111,704	$106,825	$116,209	$107,980	$108,541
Collection Service Charges	$2,986,342	$5,165,058	$3,130,010	$2,495,315	$1,437,643	$0
Connection-Reconnection Charge	$554,565	$873,835	$644,708	$516,900	$550,698	$553,890
Easement Letter	$24,978	$29,773	$39,955	$37,168	$0	$0
Misc Revenue	-$1,700	$1,625	$132,834	$114,046	$0	$0
Total	**$6,786,826**	**$9,497,848**	**$7,186,822**	**$5,966,102**	**$5,107,243**	**$3,689,939**

Account 4325 -Merchandise and Jobbing Revenue

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	$88,900	$1,722,500	$5,447,129	$2,899,790	$2,200,000	$2,200,000
Isolation	$779,822	$1,110,436	$3,245,726	$3,559,037	$3,205,922	$3,184,384
Customer and Temp Services	$4,433,778	$5,325,404	$4,771,188	$6,251,865	$4,465,678	$4,681,016
MicroFIT	$93,500	$71,060	$157,066	$69,000	$50,000	$62,500
Scrap Sales	$2,351,600	$3,264,400	$3,198,906	$2,955,541	$2,988,600	$3,048,400
Accident Claims	$2,422,022	$1,683,500	$3,281,539	$3,648,653	$2,502,500	$2,562,600
Pole & Duct Rental	$11,145,300	$18,051,800	$23,106,399	$26,147,228	$19,236,165	$20,624,017
Streetlighting[1]	$520,678	$459,415	$332,279	$377,304	$669,103	$669,103
Other[2]	$1,272,988	$1,080,869	$2,388,913	$1,491,825	$696,534	$700,595
Total	**$23,108,588**	**$32,769,384**	**$45,929,144**	**$47,400,242**	**$36,014,502**	**$37,732,615**

Account 4330 -Merchandise and Jobbing Costs

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Inventory Sales	-$110,700	-$1,661,500	-$5,240,465	-$2,954,604	-$2,000,000	-$2,000,000
Isolation	-$663,612	-$915,208	-$3,681,121	-$4,968,289	-$3,672,322	-$3,654,584
Customer and Temp Services	-$3,638,181	-$4,372,001	-$3,751,142	-$4,683,780	-$4,051,478	-$4,260,816
MicroFIT	-$47,007	-$78,191	-$25,354	-$3,061	-$50,000	-$62,500
Scrap Sales	-$1,131,000	-$863,200	-$1,048,740	-$1,557,885	-$1,300,500	-$1,326,500
Accident Claims	-$2,267,530	-$2,321,000	-$3,026,630	-$761,183	-$265,600	-$320,800
Pole & Duct Rental	-$4,771,400	-$8,416,600	-$10,670,064	-$11,047,712	-$3,502,950	-$3,553,027
Streetlighting[1]	-$476,270	-$380,939	-$302,663	-$336,850	-$569,180	-$569,180
Other[2]	-$941,865	-$797,065	-$2,167,442	-$1,093,585	-$239,658	-$243,681
Total	**-$14,047,565**	**-$19,805,704**	**-$29,913,621**	**-$27,406,949**	**-$15,651,688**	**-$15,991,088**

Account 4405 - Investment Interest Income

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Investment Interest Income	$1,298,537	$0	$9	$0	$120,000	$120,000
Regulated Assets Charges-Revenue	$0	$186,388	$0	$0	$0	$0
Total	**$1,298,537**	**$186,388**	**$9**	**$0**	**$120,000**	**$120,000**

Notes

1 The amounts reported as shared services recovery in account 4375 do not include the cost recovery associated with fleet, occupancy and IT services provided by THESL to THESI, THESU and THC presented as part of Appenix 2N. The recovery of these costs is included in the OM&A evidence as part of the Allocation and Recoveries program for an average annual value of $1.1M for the period 2015-2020.
Streetlighighting recoveries and costs related to emergency response, engineering and planning included in Appendix 2N are shown under the merchandising and jobbing section (4325 & 4330).

2 The "Other" category is composed of IT services related to Hydro One Telecom and other various adhoc services.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 84:

Reference(s): Exhibit U, Tab 3, Schedule 2, p. 2;
Exhibit 3, Tab 2, Schedule 1, p. 5

a) Will the $1.6 M gain on disposition of property in 2019 be treated the same of other property sale gains (per Exhibit 3, Tab 2, Schedule 1, page 5) and returned to customers? If not, why not?

b) If yes, please explain how and when this will occur.

RESPONSE:

a) The $1.6 million gain on disposition of utility property in 2019 is part of Other Revenue. The other property sale gains referenced in Exhibit 3, Tab 2, Schedule 1, page 5, namely 50/60 Eglinton and 5800 Yonge, are not recorded in Other Revenue because those gains are being returned to customers as part of the Operational Centers Consolidation Program (OCCP). The OCCP was a targeted facilities strategy initiative that the utility undertook starting in 2013. The OCCP business case was predicated on the disposition of the surplus properties and returning the sale gains to customers to offset the capital investment costs associated with the initiative. By contrast to the OCCP, the property sales captured in Other Revenue are part of the utility's normal activities that generate non-distribution revenue. As articulated in the response to undertaking JTC 4.21, Toronto Hydro's position is that the net gains on sales of properties should be subject to the same treatment as the other sources of non-distribution revenue included in Other Revenue.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 85:

Reference(s): **Exhibit U, Tab 4A, Schedule 2, p. 2**

Please clarify – is the entire $1 million increase in Customer-Drive work related to the facilitation for safe entry into customer owned vaults? If not what amount is related only to this activity. What is the offsetting revenue increase related to this change?

RESPONSE:

For the purposes of this response, Toronto Hydro assumes that the correct reference is Exhibit U, Tab 4A, Schedule 1, p. 2.

Yes, the entire increase in Customer Driven Work is related to the facilitation for safe entry into customer owned vaults. There is no offsetting revenue related to this change as the increase is related to the facilitation of the first free safe entry into customer owned vaults.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 86:

Reference(s): **Exhibit U, Tab 4A, Schedule 2, p. 1**

With respect to the sole sourced procurement with Bell Canada ($2.226,000) please explain what "*Purchase of demand reduction services for capacity management*" means.

RESPONSE:

Toronto Hydro is implementing the 2015-2019 Local Demand Response (DR) program at Cecil TS to reduce about 9.5 MVA of capacity during peak periods and defer $30 million in station expansion upgrades. Bell Canada has two facilities fed from Cecil TS, representing a combined average peak monthly load of about 10 MW. Bell has committed to providing 7 MW of load curtailment capacity to Toronto Hydro by 2019, at a cost of $2,226,000 to Toronto Hydro. There is no other customer load supplied by this station that can provide this quantity of demand response.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 87:

Reference(s): Exhibit U, Tab 4A, Schedule 3, Appendix A – OEB Appendix 2-K

a) Please explain the variance in the 2018 actuals amounts for Management (including Executive) of 72 FTEs and $20,025,575 in total compensation as compared to the original estimate of 68 FTEs and compensation of $19,592,344.

b) THESL explains a large part of the variance in 2018 compensation is due to the inability to negotiate a harmonized Power Line Technician role with the Power Workers Union. In the original application THESL had forecast it would have an FTE compliment for non-management positions of 1,431 by the end of 2018. In the event it has 1,353. This would appear to mean that rather than needing to hire 24 FTE positions to meet its forecast in 2019, the Company now needs to hire 102 positions. Please explain how this will be done. In doing so please explain how many positions on average are hired each year at the Utility and how many new positions have been hired since January 1, 2019.

RESPONSE:

a) The FTE and compensation variances in 2018 actual versus the original estimate are due to changes in the timing of hires and exits within the management group.

b) Toronto Hydro relies on both internal and external resources to deliver its work plans and offer safe and reliable service to customers. This approach provides Toronto

Hydro the resourcing flexibility and scalability to execute work efficiently and to manage the operational challenges that the utility may face in a given year.

The majority of the FTE variance in 2018 is attributed to the delay in hiring certified and skilled trades and designated and technical professional positions due to the inability to negotiate a settlement with the Power Workers Union regarding the Power Line Technician (PLT) role. The recruitment process for these roles is currently underway. In the meantime, Toronto Hydro plans to rely on third-party service providers to perform the work that is necessary to keep the system in good working order and continue to serve customers.

Between 2015 and 2018, approximately 150 new external employees were hired each year. Between January and May 2019, 59 new external employees were hired.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 88:

Reference(s): **Exhibit U, Tab 7, Schedule 1, p. 1 and Appendix A, p. 2; Exhibit 7, Tab 1, Schedule 3, p. 2**

It is noted that the number of Streetlight Bills (CNB) has changed from 139 to 120. Please explain why.

RESPONSE:

The number of Streetlight Bills (CNB) has decreased from 139 to 120 as a result of the closure of two Streetlight billing accounts.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 89:

Reference(s): Exhibit U, Tab 8, Schedule 1, p. 3

What would be the LU class revenue to cost ratio if all of the revenue shortfall arising from setting the CSMUR ratio at 100% and the USL ratio at 120% was recovered from the LU class?

RESPONSE:

The resulting Large Use class revenue to cost ratio would be 91.7 percent.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

INTERROGATORY 90:

Reference(s): **Exhibit U, Tab 9, Schedule 1, pp. 4-5**

There are small changes to the CRRRVA balances from the original filing to the update for 2016 (5.9 vs. 5.8) and 2017 (14.5 vs. 14.3). Please explain why?

RESPONSE:

The balances did not change from the original filing to the update. The 2016 and 2017 balances of $5.8 million and $14.3 million in the original filing, respectively, do not include carrying charges. These same balances can be found in Table 4: CRRRVA Balance on page 5 of the updated evidence in the same line labeled “Sub-account 1508 – CRRRVA”. The 2016 and 2017 balances $5.9 million and $14.5 million on this same page, represent the total balances including carrying charges in the line labeled “Total”.