ONTARIO ENERGY BOARD

File No. EB-2018-0165
Exhibit No. K1.3
Date June 27, 2018 jfs

Toronto Hydro-Electric System Limited

EB-2018-0165

OEB Staff Compendium

Panel 1

TAB 1

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME:	**Technical Conference**
DATE:	**February 19, 2019**

MR. LYBEROGIANNIS: The fan behind us is still fairly loud, and it is a little challenging. If I could ask for the IR number again.

MR. RUBENSTEIN: 2B-SEC-32.

MR. LYBEROGIANNIS: 32.

MR. RUBENSTEIN: In this interrogatory we had asked you about the status of the study. My review of the previous rate case was the expectation of this project was either --was supposed to begin or be completed in 2015. I don't recall exactly which one.

Can you help me explain why it was delayed?

MR. LYBEROGIANNIS: Mr. Rubenstein, you are correct that within the 2015 to 2019 period Toronto Hydro did plan to undertake a CIC study. I don't have the specific reference in front of me. However, it is Toronto Hydro's intent to complete that study before the end of this year.

MR. RUBENSTEIN: Okay. But my question is why was it delayed? I had read -- or understood from the previous proceeding that the point of the study was going to help inform the next plan. Obviously because of where we are right now it hasn't. I want to understand why it was delayed.

MR. LYBEROGIANNIS: The reason that we have not completed the CIC study sooner is simply a matter of available resources. The particular survey is being undertaken by resources within our asset and program management function or within the engineering team.

Over the past three years, that particular team has been working diligently on other types of tools. For example, one particular tool that we have in front of us and we just spoke about was improvements to our asset condition assessment methodology.

We also spent a considerable amount of time embracing the outcomes framework and implementing the outcomes framework within our planning environment, and the CIC study specifically was simply at that point in time determined to be one that, with limited resources, is one that we could defer into, into 2019.

MR. RUBENSTEIN: Can I ask you to turn to 2B-SEC-50. Sorry, SEC 37. My mistake. And we asked you in this interrogatory to provide a step-by-step explanation of how you cost out the programs.

As I understand it, the first step there is sort of the high-level scope of work. And as I read it, do I take it that it is essentially a desktop exercise based on a preliminary plan, you know, I need to replace ten poles, you know, a kilometre of conductor. You have a cost for that at the high-level stage and you know how much labour would be needed for that amount of work? And so you come up with a high-level cost estimate at that point?

Am I reading that generally correct?

MR. LYBEROGIANNIS: It would be what would typically be considered to be in the industry a sort of a planning-level scope of work associated with a planning high-level estimate.

In terms of whether it is simply a desktop exercise,

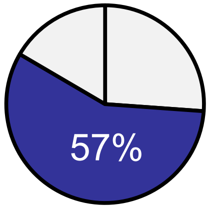
Toronto Hydro: 2020-2024

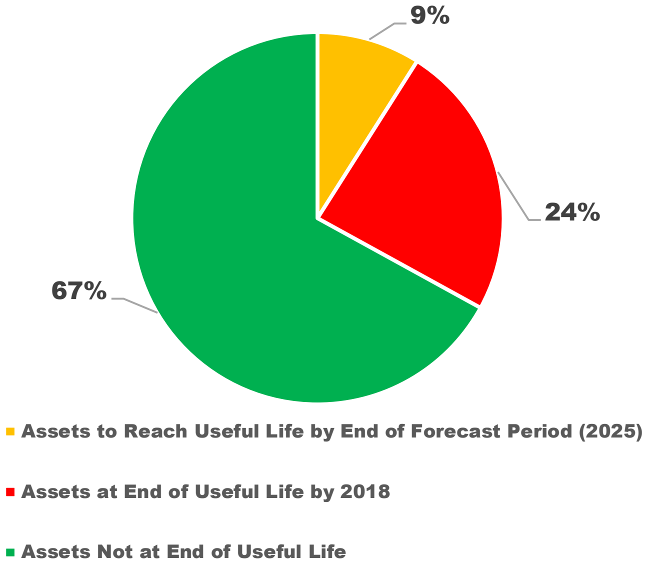
Distribution Rates Application

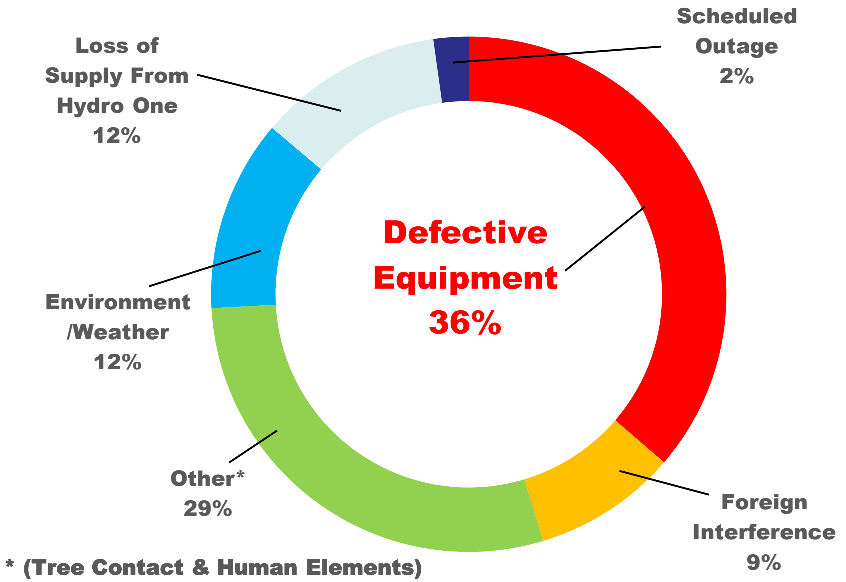
Overview

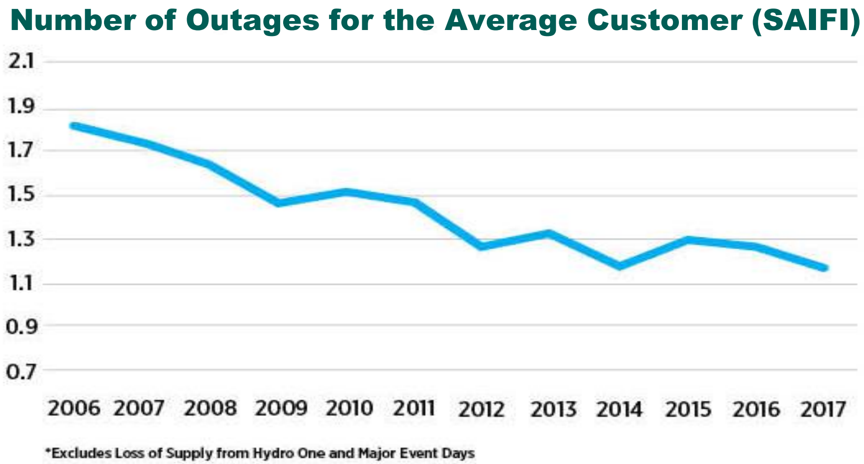
Renewing the System

Our Operating Context









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ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME:	**Evidence Overview Presentation**	
DATE:	**May 3, 2019**	
BEFORE:	**Lynne Anderson**	**Presiding Member**
	Michael Janigan	**Member**
	Susan Frank	**Member**

every year our assets age, and more assets move into that red quadrant on that pie chart of assets past their useful life.

Renewal of assets is, for Toronto Hydro, a large problem. It requires billions of dollars, sustained effort, and many years. Improving demographics is important because for Toronto Hydro deteriorated equipment is the single largest cause for unreliability; that is shown on the chart to the right.

Our plan is to continue to focus in on deteriorating equipment and defective equipment outages. As shown on the chart to the bottom right, you will see that in recent years, and as Toronto Hydro has invested consistently in its system improved demographics, what we have actually been able to achieve is an improvement in reliability. That chart is of SAIFI, and demonstrates the average customer experience when it comes to the number of outages that customers experience in a given year. You will notice considerable improvement over the last decade and a half.

The plan that we have before the Board is aimed at maintaining the gains that we have achieved. What we want to do is we do not want to fall back, and our plan is designed to do that. However, there are significant pressures that continue to exist. Our equipment inspections continue to find high levels of deficiencies. We have neighbourhoods and pockets on our system that continue to experience poor reliability, and the need for reactive and unplanned replacements continues to be high.

OEB Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	40	3%	40	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95	1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	30	3%	30	3%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices (Streetlighting Assembly)	40	3%	40	3%	Yes	No
								1835	Overhead Conductors and Devices	50	2%	50	2%	No	No
								1855	Services (Overhead & Underground)	50	2%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	30	3%	30	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	3%	32	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	3%	32	3%	No	No
	14	Station Grounding Transformer			30	40	40	1820	Distribution Station Equipment - Normally Primary Below 50 kV	25	4%	25	4%	Yes	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
			Charger		20	20	30	1820	Distribution Station Equipment - Normally Primary Below 50 kV	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	50	2%	50	2%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	Yes	No
	18	Station Switch			30	50	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	30	3%	30	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	3%	30	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	10%	10	10%	No	No
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
	23	Steel Structure			35	50	90	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	3%	35	3%	No	No
								1820	Distribution Station Equipment - Normally Primary Below 50 kV	35	3%	35	3%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	1845	Underground Conductors and Devices	60	2%	60	2%	No	No
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	Underground Conductors and Devices	20	5%	20	5%	Yes	No
								1855	Services (Overhead & Underground)	20	5%	20	5%	Yes	No
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	40	3%	40	3%	No	No
								1855	Services (Overhead & Underground)	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50	1850	Line Transformers	20	5%	20	5%	No	No
			Protector		20	35	40	1850	Line Transformers	20	5%	20	5%	No	No
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	30	3%	30	3%	No	No
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	30	3%	30	3%	No	No
	36	UG Foundation			35	55	70	1840	Underground Conduit	50	2%	50	2%	No	No
	37	UG Vaults	Overall		40	60	80	1840	Underground Conduit	40	3%	40	3%	No	No
			Roof		20	30	45	1840	Underground Conduit	20	5%	20	5%	No	No
	38	UG Vault Switches			20	35	50	1845	Underground Conductors and Devices	30	3%	30	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors and Devices	20	5%	20	5%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	30	3%	30	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80	1840	Underground Conduit	50	2%	50	2%	No	No
								1840	Underground Conduit (Cable Chamber Roof)	20	5%	20	5%	Yes	No
S	43	Remote SCADA			15	20	30	1835	Overhead Conductors & Devices	30	3%	30	3%	No	No
								1980	System Supervisory Equipment	15	7%	15	7%	No	No
								1980	System Supervisory Equipment	30	3%	30	3%	No	No

OEB Appendix 2-BB
Service Life Comparison

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
							Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	8	13%	No	No
		Trailers	5	20	1930	Transportation Equipment	5	20%	5	20%	No	No
		Vans	5	10								
3	Administrative Buildings		50	75	1908	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1908	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1908	Buildings and Fixtures	50	2%	50	2%	No	No
					1908	Buildings and Fixtures	75	1%	75	1%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold Improvements	5	20%	5	20%	Yes	Yes
5	Station Buildings	Station Buildings	50	75	1808	Buildings and Fixtures	20	5%	20	5%	Yes	No
					1808	Buildings and Fixtures	30	3%	30	3%	Yes	No
					1808	Buildings and Fixtures	36	3%	36	3%	Yes	No
					1808	Buildings and Fixtures	75	1%	75	1%	No	No
		Parking	25	30	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Fence	25	60	1808	Buildings and Fixtures	30	3%	30	3%	No	No
		Roof	20	30	1808	Buildings and Fixtures	20	5%	20	5%	No	No
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	4	25%	4	25%	No	No
					1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
					1920	Computer Equipment - Hardware	6	17%	6	17%	No	Yes
		Software	2	5	1611	Computer Software	4	25%	4	25%	No	No
					1611	Computer Software	5	20%	5	20%	No	No
					1611	Computer Software	10	10%	10	10%	No	Yes
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	6	17%	6	17%	No	No
					1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
					1950	Service Equipment	8	13%	8	13%	No	No
					1960	Miscellaneous Equipment	10	10%	10	10%	No	No
					1930	Transportation Equipment	8	13%	8	13%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	10	10%	No	No
					1970	Load Management Controls - Customer Premises	10	10%	10	10%	No	No
					1975	Load Management Controls - Utility Premises	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	5	20%	5	20%	No	No
					1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	25	4%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	40	3%	40	3%	No	No
13	Smart Meters		5	15	1860	Meters (Smart Meters)	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Additional Notes

The useful life of Toronto Hydro handwells is twenty years. The streetlighting handwells is fourty years

The useful life of the IT related data centre is ten years.

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.

See pages 17-19 of Kinetrics Report

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%

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**

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 175:

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

Preamble:

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.”

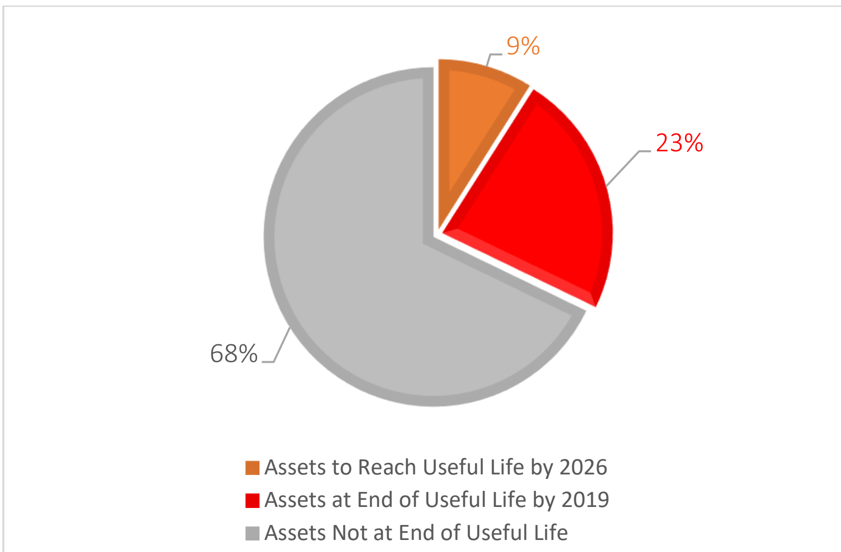


Figure 1: Percentage of Assets Past Useful Life (Updated)

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).

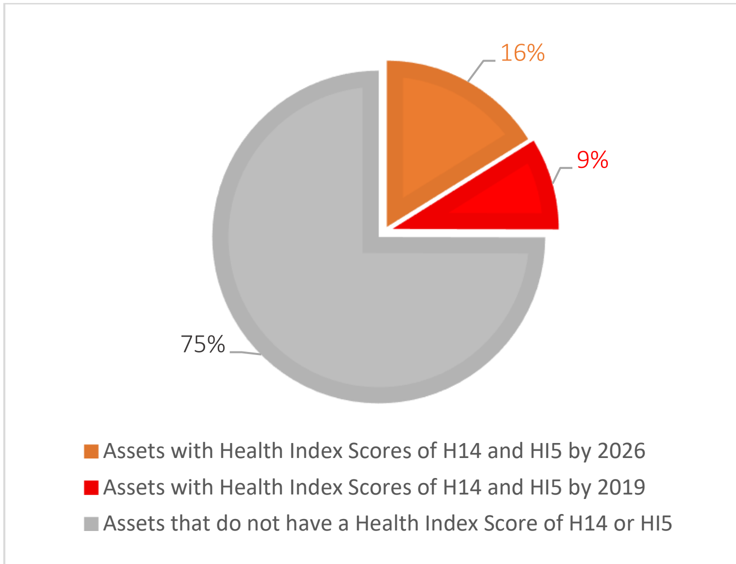


Figure 2: Percentage of Assets with Health Index Scores of HI4 and HI5 (Updated)

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.

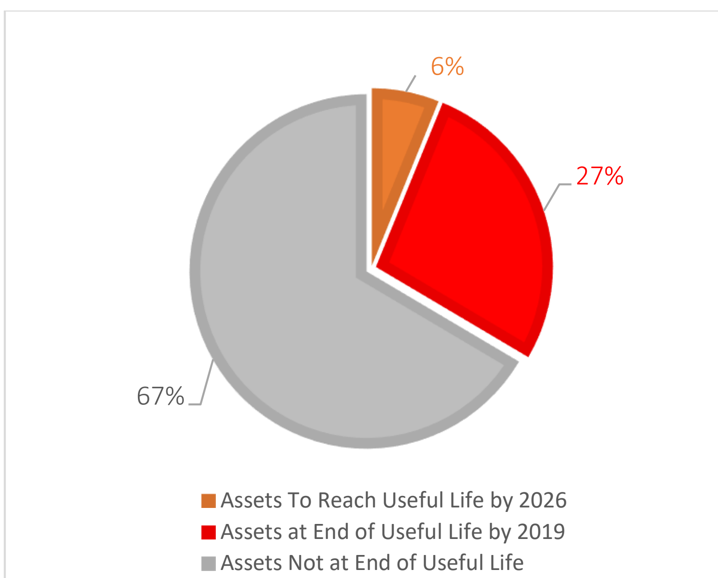


Figure 3: Percentage of Assets Past Useful Life (Excluding Asset with No ACA)

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 21:

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

THESL indicates that as of the end of 2017, approximately 24 percent of assets will be in-service past their useful life, as shown in Figure 3 below.

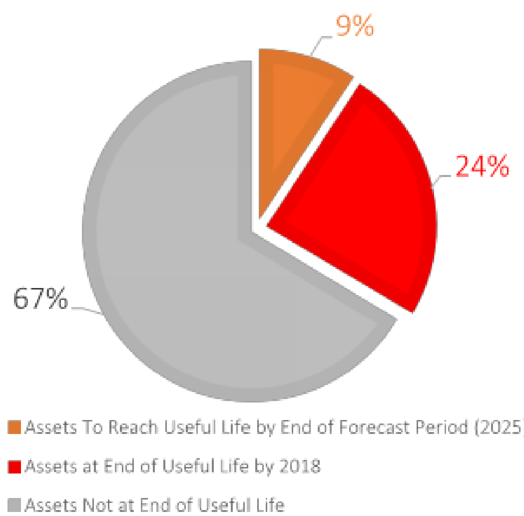


Figure 3: Percentage of Assets Past Useful Life

a) Please provide the calculation that underpins the percentages in Figure 3.

b) Please provide a pie chart that shows the Percentage of Assets with Health Index Scores of H14 and HI5 by 2018; Percentage of Assets with Health Index Scores of H14 and HI5 at the end of Forecast Period (2025); and Percentage of Assets that do not have a Health Index Score of H14 or HI5.

c) Please provide the calculation that underpins part b).

RESPONSE:

a) Please refer to Toronto Hydro's response to interrogatory 1B-CCC-12.

b) The following figure shows the percentage of assets in HI4 or HI5 condition as of the end of 2017 and the percentage of additional assets forecasted to be in HI4 or HI5 condition by 2025. Please note that this chart pertains only to the subset of asset classes for which Toronto Hydro calculates Health Scores (i.e. assets for which Toronto Hydro does not calculate health scores (e.g. cables; pole-top transformers) are excluded from the chart.

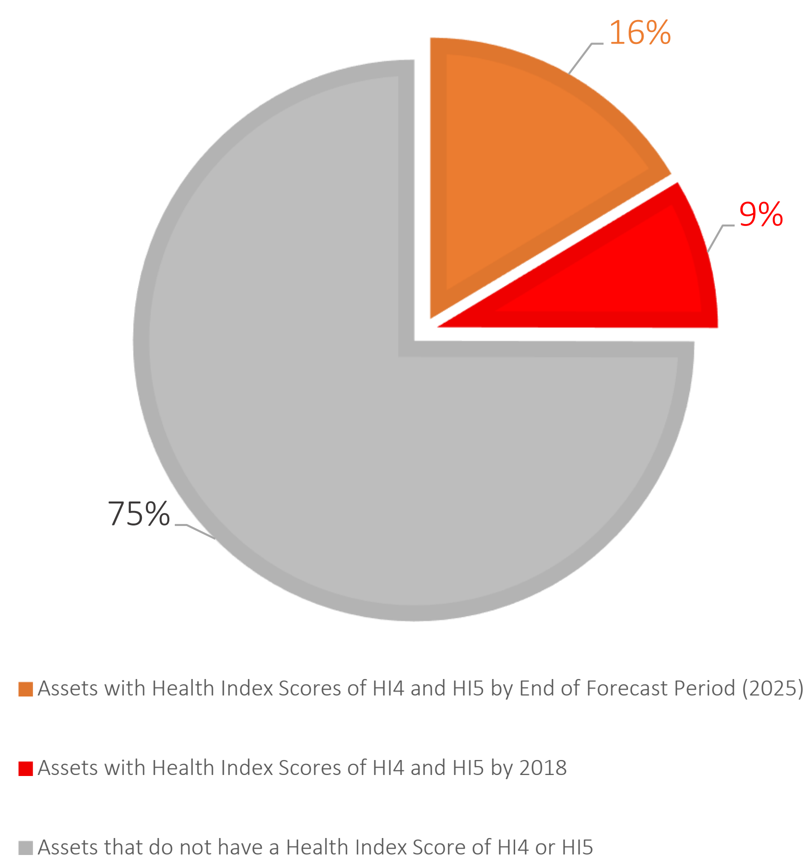


Figure 1: Percentage of Assets with Health Index Scores of HI4 or HI5

c) The data used to produce Figure 1 in part (b) above is based on the Current Health Index distribution (as of the end of 2017) provided in Exhibit 2B, Section D, Appendix C, Table 2 and the Future Health Index distribution (by 2025), provided in Exhibit 2B, Section D, Appendix C, Table 3. The 9 percent value is the current proportion of assets in HI4 and HI5. The 16 percent value is the additional proportion projected to be in HI4 and HI5 by 2025.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

UNDERTAKING NO. JTC2.14:

Reference(s): Exhibit 2B, Section E2, page 12

To provide the calculation of the denominator or, in other words, the total number of the asset population used to derive the pie chart.

RESPONSE:

Toronto Hydro follows the approach outlined in the response to interrogatory 1B-CCC-12 to calculate the percentage at and past the Mean Useful Life for each asset class or type. The total asset population is translated to a replacement value in order to establish a system level metric for use as a strategic indicator.[1]

The denominator used to calculate the percentage of assets past useful life is approximately $9.5 billion. The value of assets at end of useful life (numerator) is approximately $2.3 billion. This results in the 24% of assets at end of useful life by 2018.

[1] Note that this addresses the question from Dr. Lowry on page 77 of the transcript from Day 4 of the Technical Conference (EB-2018-0165 THESL Technical Conference Friday, February 22, 2019).

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME:	**Evidence Overview Presentation**	
DATE:	**May 3, 2019**	
BEFORE:	**Lynne Anderson**	**Presiding Member**
	Michael Janigan	**Member**
	Susan Frank	**Member**

at a least material deterioration. The methodology that we have adopted is an industry leading one. We are always looking for ways to improve our engineering analytics, and we devoted considerable effort over the last couple of years to move from a former ACA methodology to this new one.

This new one is used by Ofgem in the United Kingdom. For station assets, our circuit breakers and power transformers, the analysis shows that the number of assets in HI4 and HI5 are expected to significantly increase if we do not invest from 200 assets to 900. Given that stations are the backbone of a reliable system and given that station assets and renewal in the station environment can be challenging, challenging because often station assets are customized to a very particular location, they require significant design work before they can be replaced, and they often require coordination with other entities such as Hydro One. There is a strong need for us to increase expenditures in station renewal in the coming rate period.

Moving now from stations to the needs for our distribution lines, the next program I will speak to you about is area conversions. Area conversions funds the renewal of legacy installations. It is a continuation of efforts from recent rate periods.

One type of legacy installation is box construction. The picture on the bottom left is of Gerrard Street near Hastings Avenue in Toronto. That picture is from 1919. You will see on the right of that picture the very distinct

TAB 2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.11:

Reference(s): 2B-Staff-86, Page 2

To show how THESL will ensure there is no double-counting in the capital budget.

RESPONSE:

Approximately 10 to 20 percent of Reactive Capital Work Requests involve an intervention on an asset that is part of an existing planned capital scope of work. These requests result in less than $5 million in capital expenditures annually. For the reasons outlined in the table below, only a fraction of this work results in opportunities to reduce planned capital.[1] Where opportunities exist, Toronto Hydro has accounted for these, usually by reducing planned volumes of work. The table below provides further details on the relationship between reactive asset replacement and planned capital for each System Renewal program.

[1] Toronto Hydro estimates this fraction to be less than $2 million, or less than one percent of the total System Renewal category of expenditures.

Table 1: Effect of Reactive Replacement on Planned Capital Expenditures

Program	Effect of Reactive Replacement on Planned Capital Budget
Area Conversions	• Minimal, if any, opportunity to reduce planned capital as area conversions involve voltage conversions that necessitate changes to all transformers (due to different voltages), poles, and conductors (due to relocation from rear lots or necessary changes to pole framing). • Forecasts for planned capital are based on historical expenditures and are captured in a manner that inherently considers any available opportunities (e.g. on a per pole or per customer basis). For example, please see Exhibit 2B, Section E6.1, page 25 at line 14.

**Underground System Renewal – Horseshoe
&
Underground System Renewal - Downtown**
	• Opportunity to reduce planned capital is predominantly in the "spot replacement" of transformers (described at Exhibit 2B, Section E6.2, page 29 at line 11) and cable chambers (described at Exhibit 2B, Section 6.3, page 2, beginning at line 27). Toronto Hydro has reduced forecast units for planned capital in anticipation of reactive replacements. An example is the fact that Toronto Hydro is proposing to reconstruct only a subset of cable chambers with at least material deterioration (i.e. HI4 and HI5). (Please see Exhibit 2B, Section 6.3, page 3, lines 9-14.)
	• Other opportunities to reduce planned capital are limited due to:
	   ○ Considerable work (i.e. 11 of 69 feeders) is for voltage conversions (as noted in Exhibit 2B, Section E6.2, page 29 at line 7), which is similar in nature to Area Conversions, presenting the limitations described above; and
	   ○ The majority of the work is in areas with legacy direct buried cables or Paper Insulated Lead Cables ("PILC") and Asbestos Insulated Lead Cables ("AILC"), which are replaced in duct according to current standards, and in a manner that minimizes the number of cable splices and associated failure risks.

Program	Effect of Reactive Replacement on Planned Capital Budget
Network System Renewal	• Toronto Hydro has reduced the planned capital budget as a result of anticipated reactive capital. For example, planned capital will only address: ○ 33 Network Vaults (relative to a total of 114 that are forecasted to have at least "material deterioration" (i.e. be in HI4 or HI5 condition) by 2024 (as noted in Exhibit 2B, Section E6.4, page 2, lines 29-32); and ○ 243 Network Units (relative to a total of 267 that are forecasted to have at least "material deterioration" (i.e. be in HI4 or HI5 condition) by 2024 (as noted in Exhibit 2B, Section E6.4, page 2, lines 13-18). • Minimal, if any, opportunities exist with the Network Circuit Reconfiguration segment as this work does not benefit from Reactive Capital. This segment reconfigures and re-cables grid networks into more robust spot vaults and enhanced grids.
Overhead Circuit Renewal	• Opportunities to reduce planned capital are available for some area rebuild projects and spot replacements. Those opportunities have been considered and incorporated in the planned budget. • Considerable work (i.e. approximately half of feeders being worked on for area rebuilds) is for voltage conversions (as noted in Exhibit 2B, Section E6.5, page 19, lines 12-14), which is similar in nature to Area Conversions, presenting the limitations described above.
Stations Renewal	• Reactive Capital expenditures on Stations equipment are very limited (i.e. approximately $1 million annually) as noted in 2B-AMPCO-64. By its nature, renewal work at stations requires considerable planning and lead time. When assets fail at a station, Toronto Hydro does only minimal work reactively (i.e. only restoration and the placement of the system in a contingency state) and instead plans and executes work as part of its planned Stations Renewal Program.

failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power interruptions for customers on feeders that are experiencing especially poor reliability performance.

E6.7.4 Expenditure Plan

Table 6 provides the Historical (2015-2017), Bridge (2018-2019) and Forecast (2020-2024) expenditures for the Reactive and Corrective Capital program.

Table 6: Historical and Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Reactive Capital	39.0	50.2	52.5	54.4	52.6	56.4	57.5	58.5	59.4	60.7
Worst Performing Feeder	3.0	4.1	3.0	4.0	4.5	4.8	4.9	5.0	5.0	5.2
Total	**42.0**	**54.3**	**55.5**	**58.4**	**57.1**	**61.2**	**62.4**	**63.5**	**64.4**	**65.8**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $141.7 million in reactive capital work between 2015 and 2017, and projects to invest $248.7 million by the end of 2019 (approximately $83 million more than the 2015 -2019 forecast of $165.5 million).

The expenditures for Reactive Capital are forecasted based on historic trends in work requests volume and types, equipment failures and reliability. Given the nature of the Reactive Capital segment, actual work volumes and costs vary from year to year. The forecasts for 2015-2019 were developed in early 2014 and represented Toronto Hydro's forecast based on best available information at the time.

The predominant driver for the variance for the 2015-2019 period is that the actual volume and type of assets requiring non-discretionary replacement differed from forecast. This was unavoidable given the unpredictable nature of asset failures and volatile swings in the type and number of equipment failures from year to year. More specifically:

- The increase in reactive capital spending from 2015 to 2016 was driven by a higher number of replacements of underground transformers due to deficiencies such as oil leaks and corrosion. In 2016, Toronto Hydro replaced 601 underground transformers compared with

Project Documentation

Date Posted: 27-Apr-16 **Date Revised:** 22-Aug-17

Project Title: **Project #:** X18256

X18256 Danforth 4kV Conversion Phase 1 - B4DA, B1DA TOB1DA

Prioritization Score: 100 **Construction by** Q1-Q4 2018

AM Estimated Cost: $2,468,821 **Estimate # :** 38914

Design Work Order #

Objective:

To convert 4.16kV feeders B4DA and B1DA to 13.8kV standards with new feeders A260DA and A274DA, respectively. Ties between A200E and A260DA as well as between A260DA and A274DA will be created for contingency scenarios.

This project is the first phase of a multi-phase plan to convert all 4kV load to 13.8kV with the eventual goal of decommissioning the B1-2DA 4kV bus.

Category: System Renewal **Activity Code** 154

Program: Box Construction Conversion

Sub Program

Project Boundaries (Where Applicable) **Multiple Locations :** Yes

East: West Lynn Ave **West:** Coxwell Ave

North: Danforth Ave **South:** GO Train Tracks

Related Projects:

The Following Projects Must Be Completed Prior To This Project

X16328 MAIN TS A1-2MN Bus Repl. PHASE 2 (Civil),S18279 Danforth TS Prepare Cells #3 & 8 "Dis Sup"

The Following Projects Must Be Completed Following This Projec

Planner Nikola Dimiskovski **Engineer:** Matthew Yee

Business Units/
External Utility

- [x] **Distribution Services Eas**
- [ ] **Distribution Services Wes**
- [ ] **CCM East**
- [ ] **CCM West**

- [ ] **Stations Distribution Automation**
- [ ] **Building Facilities**
- [ ] **Coordinate with City/ Bell/ Roger/TTC/HO**
- [ ] **Easement Require**
- [ ] **Cost Sharing/Recoverable** ____ **%**

SCOPE

Background:

Box construction feeders, such as B4DA and B1DA, are a functionally obsolete legacy construction standard with numerous safety concerns and capacity limitations.

Assumptions:

Assume 4kV poles will be replaced at the same location by 13.8kV poles.

Description of Work:

SEE ATTACHED MAPS FOR MORE DETAIL

NOTES:
- This scope will follow the civil reinforcement work around Danforth Station with scope X16328
- The B6DA feeder will continue to operate as the standby for the 4kV areas until they are converted

1. CONNECT A260DA AND A274DA FROM THE A1-2DA 13.8kV BUS AT DANFORTH STATION

- Connect new feeders A260DA to cell no. 3 and A274DA to cell no. 8 on the A1-2DA bus. These cells should be prepped with scope S18279.
- Extend A260DA and A274DA to conversion areas using 500 kcmil triplexed TRXPLE cable and 1 neutral cable using the routes defined below. The S18279 scope will ensure that there is a neutral at the A1-2DA bus.
- Conduct civil inspections and rebuild cable chambers and ducts if necessary.

2. EXTEND A260DA AND NEUTRAL (1460m of cable)

- Use the following cable chamber route for A260DA and neutral: 8000, 8002, 8003, 8025, 8012, 8013, 8014, 7347, 8015, 8016, 5846, 8017, 5845, 5973, 5375, 5975, 5374, 5977, 5373, 5979, 5372, 5991, 5371, 5994, 5370, 5998, 5369, 6040.
NOTE: Going immediately north to CC8011 from CC8002 is not recommended since CC8011 would require a rebuild which cannot be done due to a moratorium on Danforth Ave.

- Rise up on or near pole P167 on Hillingdon Ave and convert B4DA as described in step 4.

3. EXTEND A274DA (1100m of cable)

- Use the following cable chamber route for A274DA: 8000, 8002, 8003, 8025, 8012, 8013, 8014, 7347, 8015, 8016, 5846, 8017, 5845, 5973, 5375, 5975, 5374, 5977, 5373, 5979, 5372, 5991, 5371, 5994, 5995.
NOTE: Going immediately north to CC8011 from CC8002 is not recommended since CC8011 would require a rebuild which cannot be done due to a moratorium on Danforth Ave.

- Rise up on or near pole P169 on Bastedo Ave and convert B1DA as described in step 6.

4. CONVERT B4DA 4KV OVERHEAD WITH A260DA

A) OH CONDUCTOR: Approximate length to convert is 1379m (primary) and 2500m (secondary). Remove all 4.16kV OH conductors. Replace main trunk with 13.8kV 336 kcmil OH treeproof. Replace laterals with 13.8kV 3/0 OH treeproof. Replace all secondary conductors with 266 kcmil XLPE.

B) POLES: Replace 54 poles with 45ft cedar poles using appropriate anchoring.

C) OH SWITCHES: Replace lateral fuses and load break switches with 13.8kV standards.

D) TRANSFORMERS: Replace 4.16kV units with 13.8kV standard transformers. The number of transformers to be used as replacements will depend on the voltage drop limitations. Designer to conduct voltage drop calculations.

Replace the following with like-for-like 13.8kV OH transformers in accordance with voltage drop limitations:
- One 50kVA (2-phase, 600V Delta) OH transformer
- Two 100kVA (1-phase, 120/240V) OH transformers
- Two 167kVA (1-phase, 120/240V) OH transformers

The following OH transformers will need to be upgraded when replaced to 13.8kV standards because they are overloaded or highly loaded. Voltage drop calculations will dictate the number, size and configuration of the replacements:
- OT20639 (1-phase, 120/240V), size: 50 kVA, peak load: 39 kVA
- OT92636 (1-phase, 120/240V), size: 100 kVA, peak load: 82 kVA
- OT64174 (1-phase, 120/240V), size: 100 kVA, peak load: 275 kVA
- OT61967 (1-phase, 120/240V), size: 50 kVA, peak load: 96 kVA
- OT40887 (1-phase, 120/240V), size: 100 kVA, peak load: 102 kVA

Replace the following with like-for-like 13.8kV padmount transformers:
- One 112kVA (3-phase, 120/208V) padmount transformer
- One 225kVA (3-phase, 120/208V) padmount transformer
- One 300kVA (3-phase, 600/347V) padmount transformer

Replace the following padmount transformer will need to be upgraded when replaced to 13.8kV standards:
- Replace padmount transformer 5927 (3-phase, 120/208V, size: 150kVA) with a 300kVA 13.8kV replacement

5. CREATE FEEDER TIE BETWEEN A260DA AND A200E

- Create feeder tie between newly converted A260DA area and A200E (Carlaw feeder) at Hanson St and Coxwell Ave using a SCADA switch. Ensure to connect to main trunk (336kcmil) of A200E. This tie will be used during contingency scenarios.

6. CONVERT B1DA 4KV OVERHEAD WITH A274DA

A) OH CONDUCTOR: Approximate length to convert is 1283m (primary) and 2500m (secondary). Remove all 4.16kV OH conductors. Replace main trunk with 13.8kV 336 kcmil OH treeproof. Replace laterals with 13.8kV 3/0 OH treeproof. Replace all secondary conductors with 266 kcmil XLPE.

B) POLES: Replace 52 poles with 45ft cedar poles using appropriate anchoring.

C) OH SWITCHES: Replace lateral fuses and load break switches with 13.8kV standards.

D) TRANSFORMERS: Replace 4.16kV units with 13.8kV standard transformers. The number of transformers to be used as replacements will depend on the voltage drop limitations. Designer to conduct voltage drop calculations.

Replace the following with like-for-like 13.8kV OH transformers in accordance with voltage drop limitations:
- Three 100kVA (1-phase, 120/240V) OH transformers
- One 501kVA (3-phase, 600V Delta) OH transformer bank

The following OH transformers will need to be upgraded when replaced to 13.8kV standards because they are overloaded or highly loaded. Voltage drop calculations will dictate the number, size and configuration of the replacements:
- OT94193 (1-phase, 120/240V), size: 100 kVA, peak load: 92 kVA
- OT98849 (1-phase, 120/240V), size: 50 kVA, peak load: 75 kVA
- OT22206 (1-phase, 120/240V), size: 50 kVA, peak load: 125 kVA
- OT58961 (1-phase, 120/240V), size: 100 kVA, peak load: 80 kVA
- OT94081 (1-phase, 120/240V), size: 50 kVA, peak load: 54 kVA
- OT4422 (1-phase, 120/240V), size: 50 kVA, peak load: 66 kVA
- OT18360 (1-phase, 120/240V), size: 50 kVA, peak load: 125 kVA
- OT81266 (1-phase, 120/240V), size: 50 kVA, peak load: 90 kVA
- OT90333 (1-phase, 120/240V), size: 50 kVA, peak load: 58 kVA

7. CREATE FEEDER TIE BETWEEN A274DA AND A260DA

- Create feeder tie between newly converted A260DA and A274DA at Hanson St and Hillingdon Ave using a SCADA switch. This tie will be used during contingency scenarios.

8. REMOVE ALL UG PORTIONS OF B4DA and B1DA

Additional Notes:

Note-1: Please apply latest Standard Design Practices (SDP).
Note-2: Please abide by ESA Requirements referring to Ontario Regulation 22/04 Section 11. This section relates to the disconnection of unused lines.
Note-3: Designers are to ensure that all leaking PILC cables (leakers) and Raychem lead repair kits that may exist within the limits of this project be identified, documented and repaired/replaced in conjunction with this project.
Note -4: Designers to include all necessary equipment nomenclature and cable tagging in the design for field implementation. [This is applicable mainly for downtown Toronto]
Note-5: For horseshoe area, if the replacement of the feeder cables for a vault is in the scope, upgrade vault to current standards by replacing all existing devices, cables and any other component that may prove unreliable due to age and/or conditions.
Note-6: Related to UG TX replacement, instructions for contractors must include specifications that vaults be cleaned and drains proven before installing the equipment.
Note- 7: all grounding deficiencies within the proposed project area be identified in the design and corrected during construction
Note-8: During the replacement of a pole mount transformer having a Transformer Monitor already installed on it, designer is to leave proper instruction for the construction crew that the existing Transformer Monitor is re-installed with the newly replaced transformer. Similarly

during the replacement of a pole and the connected conductor, designer is to instruct construction group to reinstall the monitoring devices [Power Line Monitors are clamped to the conductors and the Data Collectors are mounted approximately half way up on the pole] back to the replaced pole and conductor. Note-9: Designer to check City Program and Moratorium. Note-10: Foreign Attachment (check with Kate Parkinson). Note-11: Design hours= , Site visit hours = .

TPUCC

Project Boundar

Street #:	Major Street Name:	Street Type:	Direction:
	DANFORTH	Avenue	

From:	Street Type:	Direction:
COXWELL	Avenue	

To:	Street Type:	Direction:
WEST LYNN	Avenue	

Type of Work:	Project Status:

Timing

Start Year:	End Year	Construction Contact:
2017		

Unit of Measure:

OH		OH UG	UG - Civil	OH and UG	UG Feeder
# of Poles	# of Spans	SCADA Switches	Per meter of roadway	# of Services	Route meters

TRANSFORMERS						
U/G Primary	Dry Transforme	Network Transform	Padmount Transforme	Polemount Transforme	Submersible	Vault Transforme

Resources Type (Hours)

Power Cable Person (TCBLP)	Certified Power Line Person	Jointer (TJOIN)	Electrical Mechanic (TMECE)	Crew Leader (TLDRC)	F39Cable Installer (TINST)	Certified Crew Leader (TCRWL)	Dist and Design Technician (TTECD)	Civil Design (TDESG)

TAB 3

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Rear-Lot Conversion	26.7	14.5	8.2	5.7	10.0	18.8	26.3	25.2	28.3	14.9
Box Construction Conversion	19.6	13.6	18.7	34.3	34.4	22.7	20.8	21.1	22.0	20.7
Total	**46.3**	**28.1**	**26.9**	**40.0**	**44.4**	**41.4**	**47.2**	**46.3**	**50.4**	**35.6**

E6.1.4.1 Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $49.4 million in rear lot conversion projects between 2015 and 2017, resulting in the conversion of 2,090 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest $65.1 million by the end of 2019 to convert approximately 2,400 customers over the 2015-2019 period. Spending was approximately $16 million higher than forecast for 2015 and 2016 due to a higher than expected number of projects carried over into the 2015-2019 period and due to project costs variances that occurred as projects progressed from high level estimates to detailed designs (e.g. changes in the design configuration required by the actual conditions at the project site or project scope[5]).

Toronto Hydro plans to invest $113.5 million over the 2020-2024 period to convert approximately an additional 2,350 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed above (including the risk of prolonged outages, ranging from 5 to more than 40 hours). This rate of spending reflects the need to keep up with the pace of rear lot aging and the substantial amount of rear lot plant remaining. Over the long-term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. Figure 13 shows the estimated rate of conversion from 2015 to 2025.

[5] Project scope changes occurred as designers conducted site visits, identifying that additional or fewer assets and labour were required to execute the job based on asset condition and configuration.

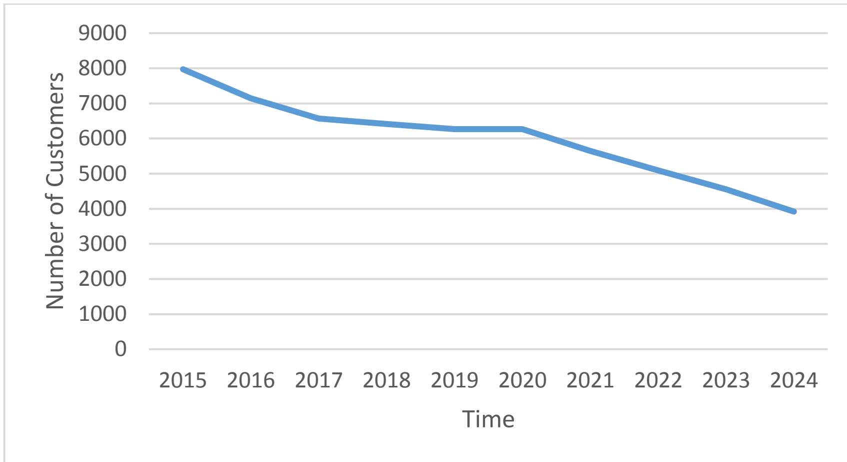


Figure 13: Rate of Conversion of Rear Lot Customers (2015-2024)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used a historical average cost per customer to parametrically estimate 2020-2024 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro examined three major rear lot areas, consisting of eight projects completed in recent years.

Toronto Hydro applied an average cost of $0.036 million per customer plus inflation and engineering and support costs in developing the segment cost forecasts for the 2020-2024 period. Note that costs for 2018-2019 are based on estimates for the projects proposed over that period and not the aforementioned average cost per customer. The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Thorncrest with 600 customers involved three phases with 200 customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 200-customer phase rear lot conversion construction project is approximately 13 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.8:

Reference(s): 2B-Staff-80(b)

With reference to IR response 2B-Staff-80, part b, the calculation of the rear lot construction program, to provide a table that proves the $36,000 is the appropriate number to use as the base cost for the forecast.

RESPONSE:

The $36,000 cost per customer for rear-lot conversion projects is based on an average of the cost per customer for the three projects listed in the table below carried out over the 2013-2017 period. More specifically, the average of $33,500, $35,300, and $39,500 is $36,100.

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

Projects Area	Number of Customers Converted	Average Cost per Customer[1]
Markland Woods	806	$33,500
Thorncrest	297	$35,300
Forest Hill	135	$39,500

Note 1: Costs include both civil and electrical work.

Toronto Hydro selected these projects to determine the average cost per customer for the 2020-2024 program because these were the most recently completed projects at the time and as such, provided the most accurate information at the time of fling.

Rear-lot projects typically have multiple phases and span multiple years. This is highlighted by Table 10 in Exhibit 2B, Section E6.1.4.1 at page 23 of 32, where civil work is executed in one year and electrical in the next. The utility incurs the resulting costs in different years. Therefore, the cost per customer can only be determined by using the total cost of a completed project divided by the number of customers converted.

Please note that in preparing this response, Toronto Hydro discovered an error in its response to 2B-Staff-80(b). Toronto Hydro states: "The cost is based on average costs from rear lot projects constructed in 2015-2017." As noted in the paragraph prior to the table above, project costs used to determine the cost per customer were over the 2013-2017 period.

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.

Rear-Lot Conversion

Toronto Hydro invested $5.0 million in Rear Lot Conversion projects in 2018 and is forecasting an additional $5.5 million in 2019. The utility anticipates completing conversion projects for 257 customers over the two-year period. Overall, Toronto Hydro is on pace to invest $59.9 million in Rear Lot Conversion projects during the 2015-2019 period, which is aligned with the original forecast in the 2015-2019 DSP and about 8 percent less than the amount previously forecast in this application.

Lower than forecast expenditures in 2018-2019 is the result of project reprioritization between years. Toronto Hydro advanced a portion of the Jamestown rear lot project (originally scheduled for 2021-2022 as noted in Exhibit 2B, Section E6.1.4.1) as the urgency of the work increased following a significant decline in reliability performance in the area. To resource this work and the continuation of the multi-phase Thorncrest rear lot project, Toronto Hydro deferred other rear lot work, including a large scope of work ($4.2 million) in the Forest Hill rear lot area. The net result of these project timing changes was a $5.2 million deferral of expenditures to the 2020-2024 period. This deferral also facilitated the allocation of resources to urgent, incremental work in the Overhead System Renewal program.

Box Construction Conversion

Toronto Hydro invested $29.4 million in Box Construction Conversion projects in 2018 and forecasts an additional $30.5 million in 2019. The utility anticipates the conversion of 1,646 poles over the two year period. Overall, Toronto Hydro is on pace to invest $111.7 million in Box Construction Conversion projects during the 2015-2019 period, which is about 9 percent more than the $102.9 million initially forecast in the utility's

TAB 4

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.

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	32.6	39.6	22.1	44.8	37.6	42.9	43.9	44.8	45.6	46.3
Generation Connection	(0.9)	0.4	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**31.7**	**40.1**	**21.9**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Connection	*Gross*	68.3	67.1	58.6	82.1	78.6	73.6	75.3	76.9	78.2	79.6
	CC[A]	(35.7)	(27.4)	(36.5)	(37.2)	(41.0)	(30.8)	(31.4)	(32.0)	(32.7)	(33.3)
	Net	**32.6**	**39.6**	**22.1**	**44.8**	**37.6**	**42.9**	**43.9**	**44.8**	**45.6**	**46.3**

[A] *CC: Customer Contributions*

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, and provincial and municipal policies regarding infrastructure and community revitalization projects. As described below, Toronto Hydro's 2020-2024 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations from various industries (such as technology,[19] design,[20] food & beverage,[21] film, financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures.

[19] Toronto is North America's fastest growing technology market - https://www.toronto.ca/business-economy/industry-sector-support/
[20] Toronto employs the largest design workforce in Canada and third largest in North America - https://www.toronto.ca/business-economy/industry-sector-support/
[21] Toronto is a major decision-making centre for the food industry in Canada, with half of Canada's top ranked food and beverage manufacturers being headquartered in the city https://www.toronto.ca/business-economy/industry-sector-support/food-beverage/

Customer Connections (Updated)	2020	2021	2022	2023	2024	Total
Gross	$ 73.60	$ 75.30	$ 76.90	$ 78.20	$ 79.60	$ 383.60
Capital Contribution	$ (35.33)	$ (36.14)	$ (36.91)	$ (37.54)	$ (38.21)	$ (184.13)
Net	$ 38.27	$ 39.16	$ 39.99	$ 40.66	$ 41.39	$ 199.47

Customer Connections (Pre-filed)	2020	2021	2022	2023	2024	Total
Gross	$ 73.60	$ 75.30	$ 76.90	$ 78.20	$ 79.60	$ 383.60
Capital Contribution	$ (30.80)	$ (31.40)	$ (32.00)	$ (32.70)	$ (33.30)	$ (160.20)
Net	$ 42.80	$ 43.90	$ 44.90	$ 45.50	$ 46.30	$ 223.40

Ref: 2B / E5.1 / p. 14 & U-Staff-166.5 / p. 3

TAB 5

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 95:

Reference(s): Exhibit 2B, Section E7.4, pp. 22-23, p. 25

a) Please advise whether the Copeland TS – Phase 1 project is now completed and the assets are in-service. If not, please provide the most recent forecast in-service date (Exhibit 2B / Section E7.4 / pp. 22-23).

b) Please provide a more detailed explanation of the events and factors (adverse weather, challenging site conditions, logistical challenges, contractor performance, etc.) that resulted in schedule and spending delays on the Copeland TS – Phase 1 project. Specifically, discuss the impact that contractor performance had on the overall budget (Exhibit 2B / Section E7.4 / pp. 22-23).

c) Please explain the statement "… the overall Copeland TS – Phase 1 budget from project inception to project completion in 2018 has not materially changed." Please provide the response in the context that the station is projected to cost $15.1 million more than the cost forecasted in the 2015-2019 rates proceeding (Exhibit 2B / Section E7.4 / p. 23).

d) Toronto Hydro states that the Copeland TS – Phase 2 project is expected to be completed by late 2023 or early 2024 (Exhibit 2B / Section E7.4 / p. 23). Please provide the forecast in-service date for the Copeland TS – Phase 2 project that was used for rate base calculation purposes.

e) Toronto Hydro states that it intends to update the Copeland TS – Phase 2 project budget in late 2018 or early 2019 (Exhibit 2B / Section E7.4 / p. 23). Please advise whether Toronto Hydro intends to update its rate base forecast (used in the C-factor calculation) to reflect the updated budget for the project.

f) Please provide breakdown between labour and material costs for the Copeland TS – Phase 2 project (Exhibit 2B / Section E7.4 / p. 25).

RESPONSE:

a) As of December 2018, one of two Hydro One transmission lines and associated HV Switchgear and one Toronto Hydro power transformer (T3) have been energized. Transformer T1, along with all remaining Toronto Hydro and Hydro One equipment is anticipated to be energized in Q1 2019.

b) The following events and factors resulted in schedule and spending delays in Copeland TS – Phase 1:

- **Unusually adverse weather events**: Copeland TS – Phase 1 was under construction (concrete and reinforcing steel placement) when the GTA experienced the ice storm of 2013-14. As well, sustained wind speeds in excess of 50 km/h required suspension of tower crane operations several times during civil construction.

- **Challenging site conditions**: Proximity to the heritage Roundhouse required special care and protection of the adjacent historic building.

- **Logistical challenges**: There was an inability to secure a large amount of road space for laydown and material delivery. Two constructors (tunnel and station) shared one live lane of Rees St. and were permitted an additional lane of Rees St. outside of rush hour traffic. This required twice daily “bump-out” of perimeter fence. Further, the delivery of two 155 tonne transformer tanks from the port of Toronto to Copeland site required 6 months of planning and engineering studies of the integrity of the structures along the route.

- **Contractor performance**: The general contractor’s UK parent company entered into compulsory liquidation on January 15, 2018. In Canada, the general contractor entered into creditor protection on January 26, 2018. The contractor’s pace of work in the first half of 2018 was thereafter significantly curtailed. This adversely impacted the project schedule, requiring Toronto Hydro to mobilize another general contractor to complete the required work. This incurred additional cost and time. In addition, Hydro One encountered failures with some of the critical components of their HV switchgear near the final stages of their commissioning. Hydro One was initially forecasted to complete their work by Q3 2018. However, as a result of this issue, they are now expected to finish in Q1 2019. Furthermore, the Copeland project will suffer incremental costs due to energization occurring in two separate phases (2018 and 2019) and requiring remobilization of various parties.

c) The latest forecast for the Copeland TS Phase 1 project is $204 million, compared against a $195 million initial budget (EB-2012-0064), or approximately a 4.7 percent increase of total budget, which is not unanticipated for a project of this size and complexity.

The $15.1 million differential arises when the Copeland forecast cited in EB-2014-0116 of $51.6 million in the 2015-2019 period is compared to the budget referenced in EB-2018-0165 of $66.7 million. Approximately $6.1 million of the 2014 spend initially forecasted in EB-2014-0116 was deferred to the 2015-2019 period because of the delay in project progress in the latter half of 2014. The remainder of the $15.1 million differential (i.e. $9 million) is noted in Table 1 below as an increase in spend on Copeland TS – Phase 1 over the original EB-2014-0116 plan. This differential is the result of the factors described in Toronto Hydro's response to part (b) above.

Table 1: OEB Approved Cost versus Current Cost Forecast

Item	Description	OEB Approved Cost ($M)	Current Forecast – 2018 ($M)
Station Cost	**Land**	5.6	5.6
	Building	53.3	66.7
	Substation Equipment	52.6	45.5
	Distribution Modification	2.3	2.3
	Design & Construction PM – Substation	6.2	26.1
Tunnel	**Design & Construction PM**	0.6	3.5
	Construction	14	14.4
Hydro One	**Capital Contribution**	60.4	39.9
	Total Cost:	195.0	204.0

d) For the purpose of rate base calculation as it applies to Copeland TS – Phase 2 "In-Service Attainments" (ISA), the following financial years were used:
- ISA of MV Switchgear (A5-6CX and A7-8CX, A9CX – Transfer Bus) in 2022;
- ISA of Power Transformers (T2, T4 and T5) in 2023; and
- ISA of remainder spending required for Phase 2 project closing in 2024.

e) At this time, there is no expectation of any significant variances in the 2019 forecast for Copeland TS – Phase 2 project as compared to what was filed. Accordingly, no updates are expected to be made to the 2019 rate base calculation.

f) Toronto Hydro does not have a cost breakdown between labour and materials for Copeland TS – Phase 2. However, cost breakdown is available based on type of work and asset type as illustrated in Figure 1 below:

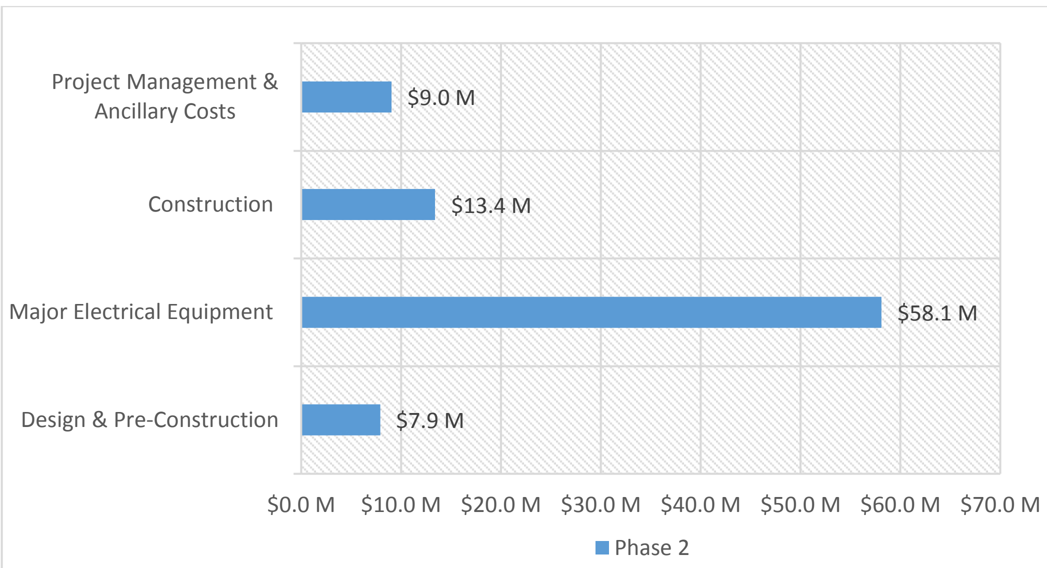


Figure 1: Copeland TS –Phase 2 Cost Breakdown

TAB 6

Toronto Hydro-Electric System Limited
EB-2018-0165
Technical Conference
Schedule JTC1.18
Appendix A
FILED: March 29, 2019
(21 pages)

Copeland TS Phase 2 Briefing

September 5, 2017

Tom Odell

Budget Forecast

- Forecast estimated using comparable (actual) phase 1 costs, impact of time, key lessons learned, and unique difficulties inherent in phase 2 (energized station, public access, etc)
- Budget and ISA forecast anticipated to be revised with more accurate figures from RFP bid responses by early next year
  - Final OEB filing expected to be based on this revised budget
- Budget based on assumption that OEB decision by end of 2019
- Timing and budget to be validated/updated based on schedules/costs from RFP responses

	Current (approved)				Future OEB Filing					
	2017	2018	2019	2015-2019	2020	2021	2022	2023	2020-2024	Total
CAPEX Forecast ($M)	$ 0.5	$ 1.8	$ 7.8	$ 10.0	$ 8.9	$ 29.7	$ 38.8	$ 1.0	$ 78.5	$ 88.5

Major Activities:	Major Activities:
RFP Development, Selection & Contract	Procurement & Installation of Electrical Equipment and Cable
Design & Pre-Construction	Construction
	Testing/Commissioning
	Third-party Review/Verification/Payment Verification
	THESL Project Management

- Assets are expected to be ISA between 2021 to 2024 (depends on construction schedule)

E7.4.3.1 Copeland TS – Phase 2

The Copeland TS – Phase 2 is required to address capacity constraints in the downtown core, which continues to experience a high degree of densification and growth as identified in the most recent Regional Planning Needs Assessment report (i.e. IRRP, see Table 5 and Table 32). The Copeland TS - Phase 2 project is incremental to Phase 1 and is intended to make full use of potential capacity at the Copeland TS site. This will: (i) reduce loading on highly loaded buses at surrounding stations, allowing Toronto Hydro to continue to connect customers efficiently within the station service areas; and (ii) create 40 spare feeder positions, enabling load transfers through switching operations and new customer connections. Copeland TS - Phase 2 will provide an additional 144 MVA in the downtown area by 2024. This includes the installation of two additional 72 MVA busses, three gas insulated power transformers (two load-serving and one back-up) and the installation of a transfer bus.

Based on Toronto Hydro's most recent 10-year station load forecast[7] three downtown stations will require capacity relief in the 2020-2024 period: Windsor TS, Cecil TS, and Terauley TS. Figure 1 below provides a visual overview of these stations with an indication of when the busses are projected to require capacity relief. Typically, load relief on a 13.8 kV downtown station bus is required when the forecasted peak load of the bus reaches 95 percent of the bus firm capacity.

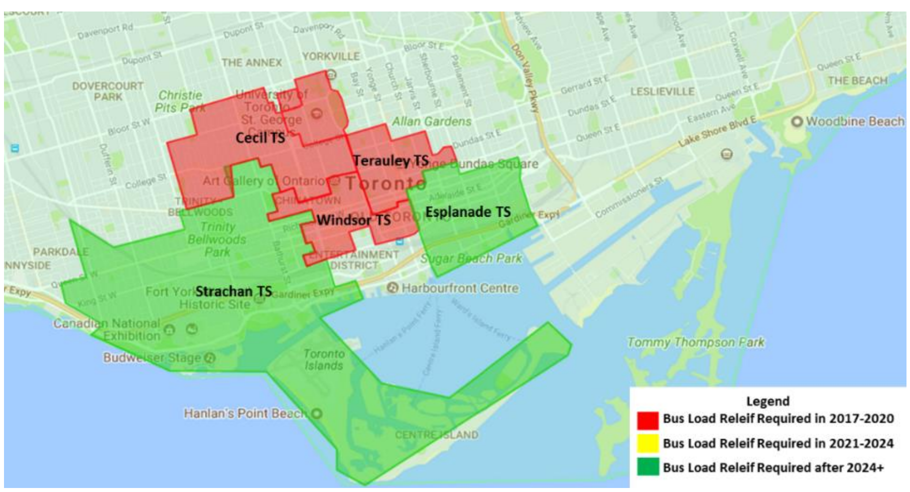
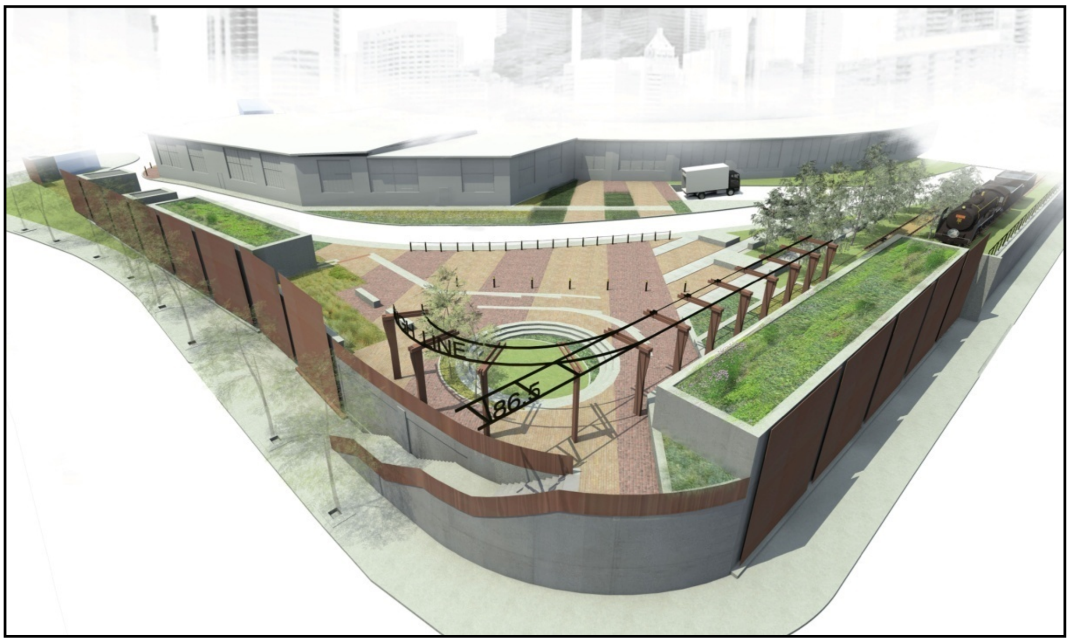


Figure 1: Geographical spread of Downtown Core Stations with a visual overview of bus load relief requirements

[7] Described in Exhibit 2B, Section D2.3 System Utilization

ICM Business Case Evaluation

Bremner TS



Toronto Hydro-Electric System Limited (THESL)

III NEED

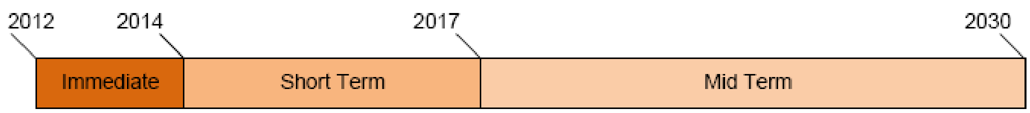


Figure 4: Immediate, Short Term and Mid-Term need timeline

1. Immediate Need (By 2014)

Windsor TS is currently using end-of-life air blast switchgear to supply key customers in Toronto's financial district. This 13.8 kV air blast switchgear, which was installed in 1956, needs to be replaced in stages (one bus at a time). In order to do so, existing loads served by the affected equipment will need to be transferred to another supply source, with 72 MVA capacity. This is an immediate need and action should be taken to complete this transfer as soon as is physically possible. The Windsor TS switchgear upgrade work has been included separately in the Stations Switchgear segment found at Tab 4, Schedule B13.2, Section II, 4.

2. Short-term need (2014 to 2017)

In the short-term, additional capacity will be required to avoid overloading at three of the five key downtown stations.

THESL completes load forecasts for each of the 35 stations in downtown Toronto on a yearly basis. The methodology associated with these forecasts has been summarized in Appendix 2 to this narrative.

Based on THESL's load forecast, Table 2 below summarizes the anticipated load increases for the five downtown stations to 2017. As indicated in Table 2, overloading at Windsor TS is expected to occur by 2017. In addition, overloads at Esplanade TS, Terauley TS, and Cecil TS are expected

TAB 7

customer-specific reliability, such as power quality enhancements, momentary outage avoidance, and increased resiliency. As such, the customer can derive both financial and reliability benefits from the same ESS asset. The costs of the investment are presumptively fully allocated to that customer, as discussed above.

Customer reliability needs can be met regardless of whether the ESS is located "in front of the meter" (i.e. traditionally thought of as "grid side") or "behind the meter" (i.e. traditionally thought of as "customer side"). That is, the physics of ESS confers distribution service benefits to the customer in either scenario. For this reason, if reliability were the only customer need that Toronto Hydro needed to address, the distribution asset would typically be located in front of the meter.

However, to meet the customer's financial need, Toronto Hydro has to site the ESS behind the meter, so that it can draw electricity during non-peak hours (for which the customer would incur the associated charges) and discharge during potential peak hours to achieve peak-shaving.

Customers generally prefer to meet both their reliability need and financial need through a single, economically efficient investment. In response, Toronto Hydro proposes to meet that need with Customer-Specific ESS projects that are located where customer benefits can be maximized.

E7.2.4.3 Expenditure Plan

Table 19 shows the gross capital expenditures for the Customer-Specific ESS segment, which is entirely funded by capital contributions from the beneficiary customers. The net impact to Toronto Hydro rate base is $0 over the 2015-2024 period.

Table 19: Bridge & Forecast Customer-Specific ESS ($ Millions)

	Bridge		Forecast					Total
	2018	2019	2020	2021	2022	2023	2024	
Metrolinx ECLRT	9.6	17.7						**27.3**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC Arrow Garage			12.3					**12.3**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**9.6**	**17.7**	**24.3**	**12.1**	**5.9**	**0.0**	**0.0**	**69.6**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.13:

Reference(s): 2B-Staff-87(d)

To provide the calculation used to calculate the capital contribution amount.

RESPONSE:

Toronto Hydro applies the OEB's economic evaluation model to determine the capital contribution for a customer-specific Energy Storage System (ESS). This model takes into consideration the capital construction and the operation and maintenance costs associated with the ESS, and ensures that these costs are appropriately borne by the customer. To illustrate, Table 1 below provide a breakdown of the capital contribution made by Metrolinx under the Offer to Connect for the Metrolinx Eglinton Crosstown Light Rail Transit ESS project, filed in response to interrogatory 1C-EP-19 at Appendix A.

Table 1: Metrolinx ECLRT Cost Breakdown ($ Millions)

Cost Description	Cost
Toronto Hydro (Labour & Material)	1.59
EPC Designer Builder Contractor (Labour & Material)	26.27
OM&A[1]	4.64
TOTAL	**32.5**

[1] The OM&A costs cover a ten year period and include, but are not limited to, preventive/predictive maintenance; management of third-party work related to third-party warranties; and 24/7 remote monitoring.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 90:

Reference(s): **Exhibit 2B, Section E7.2, pp. 29-42**
Exhibit 2B, Section E7.2, p. 32
Exhibit 2A, Tab 4, Schedule 1, p. 2
EB-2011-0004, Report of the Board: Supplemental Report on Smart Grid
Affiliate Relationships Code for Electricity Distributors and Transmitters

Preamble:

Toronto Hydro noted that customer reliability needs can be met regardless of whether the ESS is located "in front of the meter" or "behind the meter" and that the physics of ESS confers distribution service benefits to the customer in either scenario. Toronto Hydro further noted that if reliability were the only customer need that Toronto Hydro needed to address, the distribution asset would typically be located in front of the meter. However, to meet the customer's financial need, Toronto Hydro has to site the ESS behind the meter to achieve peak-shaving (Exhibit 2B / Section E7.2 / p. 32).

Toronto Hydro confirmed that no non-distribution activities are included in its proposed capital plan (Exhibit 2A / Tab 4 / Schedule 1 / p. 2).

The OEB reaffirmed that the provision of behind the meter services and applications that fall within the parameters set out in sections 71(2) or 72(3) of the OEB Act is a non-utility activity (EB-2011-0004 / Report of the Board – Supplemental Report on Smart Grid / p. 5). In accordance with the OEB's policies related to activities under those sections, such activities must be accounted for separately from utility activities and be undertaken on a full cost recovery basis (i.e. not recovered in rates).

The Affiliate Relationships Code for Electricity Distributors and Transmitters sets out requirements to prevent a utility from cross-subsidizing affiliate activities and prevent a utility from acting in a manner that provides an unfair business advantage to an affiliate that is an energy service provider.

a) Please confirm Toronto Hydro's intention to own behind the meter storage units as distribution assets.

b) In light of the OEB's determination on behind the meter activities (EB-2011-0004 / Report of the Board – Supplemental Report on Smart Grid / p. 5), and Toronto Hydro's statement that no non-distribution activities are included in its proposed capital plan (Exhibit 2A / Tab 4 / Schedule 1 / p. 2), please explain why Toronto Hydro believes providing behind the meter ESS services is a distribution activity.

c) Please explain why Toronto Hydro is not delivering these services through an affiliate given that it is a competitive activity.

d) Please advise whether the customers that are being provided behind the meter ESS are aware that this is not a distribution service and, therefore, they are not required to procure this service from Toronto Hydro.

e) Please provide a breakdown of the cost estimates in Table 19 (Exhibit 2B / Section 7.2 / p. 32) assuming this service were provided through an affiliate instead as part of the regulated distribution business. The breakdown should include Toronto

Hydro's fully-allocated cost to provide services to the affiliate, as well as the estimated fair market value for the service provided by the affiliate to Toronto Hydro, as contemplated in section 2.3 of the Affiliate Relationships Code.

RESPONSE:

a) Confirmed.

b) The ESS infrastructure proposed provides varying degrees of benefit to the distribution system. On the basis that costs should follow benefits, the ESS infrastructure that provides benefits to customers beyond the host site customer are properly classified as part of the distribution system, irrespective of its location in relation to a meter.

The cited Report also states on page 9:
"The Board's intention is to provide guidance in a holistic manner, recognizing that the modernization of the electricity system is a continuous process with no specific endstate. The circumstances and needs of an electricity distributor's system and its customers vary significantly across the province. The Board has sought to provide as much guidance as possible to provide a long-term view of electricity network enhancement without prescribing specific investments, technologies, methodologies or standards, or applying procurement requirements and targets."

Toronto Hydro has pursued these ESS investments and proposes to continue to pursue them, mindful of the guidance in the Report, and in alignment with these core principles set out in the Report. Further, Toronto Hydro respectfully notes that over the past five years since the Report was prepared, there have been significant changes to technology, customer preferences, and other variables that the sector need to be responsive to. The OEB's *Strategic Blueprint: Keeping Pace with an Evolving Energy Sector*, issued in December 2017, reflects these changes and the need to innovate to keep pace with them.

c) Toronto Hydro's ESS program provides benefits to customers through "non-wires" investments (i.e. energy storage systems) that it would otherwise provide using "wires" investments to the distribution system. Accordingly, Toronto Hydro's view is that these are distribution activities and a distributor is eligible to carry them out. Toronto Hydro recognizes that in some instances customers will choose other means of receiving those benefits, including contracting with non-utility energy services providers. Toronto Hydro facilitates those connections per the normal course in accordance with its obligation to provide access to the system.

d) Where there is a host site customer, it is nearly always if not always the case that the customer contacts Toronto Hydro requesting in general a solution to a desire for greater service quality or more specifically an energy storage system. These large sophisticated customers are aware that Toronto Hydro is not the only option for meeting these needs with respect to behind-the-meter solutions.

e) Toronto Hydro does not have an affiliate that provides energy storage systems to customers.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 88:

Reference(s): **Exhibit 2B, Section E7.2, p. 2, p. 17, p. 25, p. 29, p. 38**

Preamble:

Toronto Hydro proposed three categories of ESS investments: (a) grid performance; (b) renewable enabling investments; and (c) customer-specific ESS (Exhibit 2B / Section E7.2 / p. 2).

For ESS, Toronto Hydro stated that one of the benefits would be the deferral of conventional infrastructure investments (Exhibit 2B / Section E7.2 / pp. 17, 29).

Toronto Hydro notes “ESS is not always the most economic REI option” and has planned wires solutions in most instances as a result (Exhibit 2B / Section E7.2 / p. 25).

a) Please explain how Toronto Hydro determines the value of deferred capital investment for the purpose of comparing the costs and benefits of its investment options.

b) Please provide a table showing the amounts of deferred capital investment as a result of the ESS projects by category and project.

c) Please provide a table showing the expected timeframe for each deferred investment (i.e. the estimated amount of time until the deferred investment must be made).

d) Please indicate the difference in the estimated costs of the conventional infrastructure investments if those investments were made now versus if they are made later on (having deferred the need for investment with the proposed storage projects).

e) Please indicate whether any results from Toronto Hydro's existing storage projects were used to estimate the costs and benefits of the storage projects proposed in this application. If yes, please summarize.

f) Given that energy storage is not always the most economic option, please elaborate on how Toronto Hydro determined that energy storage was appropriate in some instances but not other instances, where different forms of grid performance or REI investments are proposed.

g) Please explain the basis for the estimates of the cost of ESS, which appear to be CAD$526 per kWh for deployments in 2018 through 2024, and reconcile with the statement that ESS costs "continue to decline…from US$300 per kWh in 2015 to an expected US$110/kWh in 2024" (Exhibit 2B / Section E7.2 / p. 38).

RESPONSE:

a) Toronto Hydro's evidence is that ESS investments have the general benefit of deferring investments in generation, transmission, and distribution infrastructure. As set out in the evidence cited in this interrogatory, one of the benefits of ESS projects is that they present a future opportunity for demand response and grid capacity relief, thereby avoiding and/or deferring the need for distribution infrastructure investments. The importance of doing so is highlighted in the Load Demand Program at Exhibit 2B, Section E5.3, though that approach has historically been "poles and wires" solutions, whereas ESS is expected to increasingly offer a feasible "non-wires" alternative. The Local Demand Response initiative set out at Exhibit 2B, Section E7.4.3.3 is an example where this deferral has occurred using a non-wires approach at Cecil TS. In assessing the deferral of capital expenditures, both the amount of the deferral and the duration of the deferral are key considerations, as well as engineering and operational considerations related to the suitability of the technological alternatives.

b) This information is not yet known.

c) Please see the response to part (b).

d) Please see the response to part (b).

e) Learnings from Toronto Hydro's current energy storage projects have helped Toronto Hydro plan the energy storage projects proposed in this segment. Please refer to Exhibit 2B, Section E7.2.3.3, page 24.

f) For proposed energy storage projects, Toronto Hydro evaluates the costs and benefits of the investment. This allows Toronto Hydro to assess the appropriateness of ESS. Please refer to Toronto Hydro's response to interrogatory 2B-SEC-65 for an example of this analysis. For further information on instances where Grid Performance and Customer-Specific ESS would be chosen, please also refer to pages 14-16 and 26-28 of Exhibit 2B, Section E7.2.

g) The referenced cost of ESS outlined in Bloomberg New Energy Finance (July 5, 2017) is for lithium-ion batteries only. The cost estimates reflected in this program represent the all-in cost of deploying ESS, which includes design and construction, installation, other equipment, and overheads.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.12:

Reference(s): **2B-Staff-90(c)**
Exhibit 2B, Section E7.2, p. 31

To clarify the reference to codes and rules in the response to IR 2B-Staff-90, part c.

RESPONSE:

In reviewing the transcript Toronto Hydro notes that there are two parts to this undertaking. The first part is to provide the source of Toronto Hydro's obligations to facilitate energy storage connections per the normal course in accordance with obligations to provide access to the system. The second part is to provide references to the OEB's applicable codes and guidance that support the recovery of a capital contribution for behind-the-meter energy storage systems.

Toronto Hydro facilitates all customer requests for service, including requests for a customer-specific energy storage systems (ESS), in accordance with its obligation to provide access to the system, as outlined in applicable statues, codes, and regulations:

- Electricity Act, 1998
    - Section 26 (Obligation to Provide Non-Discriminatory Access)
    - Section 28 (Distributor's Obligation to Connect)
    - Section 29 (Distributor's Obligation to Sell Electricity)
- Distribution System Code
    - Section 6.2.4 (Generation Connections)

TAB 8

- Section 7.2 (Customer Connections); and
- Ontario Energy Board Act, 1998
    - Section 57 (Requirement to Hold Licence)
    - Section 70 (Licence Conditions)
- Toronto Hydro's Electricity Distribution Licence
    - Section 6 (Obligation to Provide Non-discriminatory Access)
    - Section 7 (Obligation to Connect)
    - Section 8 (Obligation to Sell Electricity)

Toronto Hydro applies the OEB's economic evaluation model to determine the appropriate capital contribution for an expansion of the distribution system to facilitate a customer's service request. The application of this methodology to a customer-specific ESS ensures that the costs are appropriately borne by the customer requesting the service. If the ESS provides a direct benefit to the distribution system, a detailed benefits assessment could be undertaken to determine a different apportionment of costs between the customer and the utility.

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

<u>Preamble:</u>

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 2020-2024 period which resulted 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 2020-2024 resulting from the above 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

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)	$ 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**

			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)	$ 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**

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)	$ 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

		2020 MIFRS		
OEB	**Description**	**Depreciation Expense**	**Derecognition**	**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

2. GROSS ASSETS

2.1 Breakdown by Function

Table 7: 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	39.1
Distribution Plant	3,047.0	3,471.1	3,803.4	4,196.4	4,551.0	4,996.0
General Plant	354.0	482.3	599.8	683.2	741.1	811.7
Gross Fixed Assets Before CWIP	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
CWIP	577.7	502.9	485.8	396.4	381.1	367.7
Total Including CWIP	**3,984.5**	**4,462.3**	**4,925.9**	**5,313.9**	**5,716.6**	**6,214.5**

Note: Variances due to rounding may exist

2.2 Breakdown by Major Plant Account

Appendix C presents the gross assets breakdown by major plant account based on the uniform system of accounts for 2015-2020.

3. WORKING CAPITAL ALLOWANCE

The Working Capital Allowance filed at Exhibit 2A, Tab 3, Schedule 1 was based on the updated Lead/Lag study applied to forecast revenue, cost of power and eligible expenses.

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. As noted in 2A-Staff-53, Toronto Hydro proposes to include the updated Cost of Power forecast, based on the OEB's Appendix 2-Z (with the most up-to-date forecasts of energy prices), during the Draft Rate Order process.

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. The utility requests that this change be approved by the OEB as part of the 2020 test year and in the calculation of the custom capital factor in the 2021-2024 rate years. However, as the net impact of this is expected to partially offset the change in WCA flowing from the updated Cost of Power, in the interest of efficiency, Toronto Hydro has not updated the 2020 revenue requirement and 2021-2024 custom capital factor at this time. If the change is approved by the OEB, the utility proposes to incorporate it during the Draft Rate Order process.

Rate Base	**2020**	**2021**	**2022**	**2023**	**2024**		Ref:	
Averge PP&E NBV	$ 4,369.70	$ 4,601.85	$ 4,844.40	$ 5,128.45	$ 5,393.19		2020 All	Table 3: U-Staff-168
WCA	$ 235.20	$ 239.10	$ 243.60	$ 248.20	$ 254.00		2021-2024	
Rate Base	$ 4,604.90	$ 4,840.95	$ 5,088.00	$ 5,376.65	$ 5,647.19		PP&E	U-Staff-168 / Appendix A
							WCA	2A-Staff-52 / Appendix A

Revenue Requirement	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**		
CRR	$ 541.40	$ 580.30	$ 596.50	$ 649.00	$ 690.20	$ 3,057.40	CRR	Table 4: U-Staff-168
Non-CRR	$ 231.30	$ 233.38	$ 235.48	$ 237.60	$ 239.74	$ 1,177.51	Non-CRR	Table 1: Exhibit U / T6 / S1
Base RR	$ 772.70	$ 813.68	$ 831.98	$ 886.60	$ 929.94	$ 4,234.91		(for 2021-2024 escalated for I-X)

CAPEX	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**		
U-IRR Net CAPEX Update	$ 521.60	$ 581.80	$ 587.10	$ 565.70	$ 574.40	$ 2,830.60	Update	U-Staff-168 / Appendix B / p. 8
Pre-Filed Net CAPEX	$ 518.40	$ 581.80	$ 587.10	$ 565.70	$ 574.40	$ 2,827.40	Pre-filed	JTC1.2
Variance	$ 3.20	$ -	$ -	$ -	$ -	$ 3.20		

In-Service Additions	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**		
U-IRR ISA Update	$ 539.90	$ 474.90	$ 587.40	$ 590.50	$ 583.60	$ 2,776.30	Update	U-Staff-168 / Appendix A
Pre-Filed ISA	$ 489.80	$ 483.70	$ 590.90	$ 593.00	$ 586.10	$ 2,743.50	Pre-filed	2A-Staff-52
Variance	$ 50.10	$ (8.80)	$ (3.50)	$ (2.50)	$ (2.50)	$ 32.80		

REVENUE REQUIREMENT

1. BASE REVENUE REQUIREMENT

Exhibit 6 presents the 2020 revenue requirement that Toronto Hydro is asking the OEB to approve in its application. As part of this application update, a number of relatively minor changes have been identified throughout Exhibit U that affect the 2020 revenue requirement. These changes are summarized in Table 1 below. The estimated net impact of the changes is an increase in revenue requirement of $0.9 million.

Table 1: Identified Changes to 2020 Forecast Revenue Requirement ($ Millions)

	2020 Test Year	Identified Changes	Reference
OM&A Expenses (incl. property taxes)	277.5	0.5	Exhibit U, Tab 4A, Schedule 1, page 1
Amortization/Depreciation	268.7	-	
Income Taxes (Grossed up)	34.7	(0.1)	Exhibit U, Tab 2, Schedule 1, section 3
Deemed Interest Expense	100.8	(0.2)	
Return on Deemed Equity	162.8	(0.3)	
Service Revenue Requirement	**844.5**	**844.4**	
Revenue Offsets	47.7	(1.0)	Exhibit U, Tab 3, Schedule 2, page 2
Base Revenue Requirement	**796.8**	**797.7**	

In the interest of efficiency, Toronto Hydro has decided not to flow these changes through the revenue requirement work form and cost allocation models. The utility requests that the OEB approve these changes as part of the 2020 test year, and proposes to make the updates as part of the Draft Rate Order process.

The 2020 Revenue Requirement Workform is attached as Appendix A to this schedule and reflects updates to the Load Forecast, Cost Allocation, and Rate Design.

Revenue Requirement	2020	2021	2022	2023	2024	Total
CRR	$ 541.40	$ 580.30	$ 596.50	$ 649.00	$ 690.20	$ 3,057.40
Non-CRR	$ 231.30	$ 233.38	$ 235.48	$ 237.60	$ 239.74	$ 1,177.50
Base RR	$ 772.70	$ 813.68	$ 831.98	$ 886.60	$ 929.94	$ 4,234.90
I		0.0120	0.0120	0.0120	0.0120	
X		0.0030	0.0030	0.0030	0.0030	
Cn		0.0503	0.0199	0.0631	0.0465	
Scap		0.7132	0.7170	0.7320	0.7422	
G		0.0020	0.0020	0.0020	0.0020	
CPCI		0.0488	0.0183	0.0613	0.0446	
RR Funded		$ 810.40	$ 825.23	$ 875.83	$ 914.86	

TAB 9

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 52:

Reference(s): **Exhibit 2A, Tab 1, Schedule 1, p. 2**
Exhibit 2A, Tab 4, Schedule 1, p. 3
Exhibit 1B, Tab 4, p. 9
Exhibit 4B, Tab 1, Schedule 1, pp. 3-4

<u>Preamble:</u>

In calculating rate base, Toronto Hydro takes an average of opening and closing PP&E NBV and adds the working capital allowance (Exhibit 2A / Tab 1 / Schedule 1 / p. 2).

In calculating depreciation expense, Toronto Hydro uses the month in which the asset comes into service (as opposed to the half-year rule). Similarly, Toronto Hydro calculates depreciation associated with assets that are retired or fully depreciated within a given year based on the month of transaction (Exhibit 4B / Tab 1 / Schedule 1 / pp. 3-4).

a) For the rate base calculation, in terms of capital in-service additions, does Toronto Hydro simply add all of the assets that went into service in a given year to the closing PP&E cost amount, with no adjustments to recognize when (which month) the asset came into service within the year?

b) For the rate base calculation, in terms of depreciation, does Toronto Hydro: (a) use the depreciation expense calculated based on its monthly approach and add that amount to the closing accumulated depreciation; and (b) then average opening and closing PP&E NBV?

c) Please advise whether Toronto Hydro agrees that there is a disconnect between the manner in which it includes capital in-service additions (annual average of annual capital additions) and depreciation expense (annual average of monthly depreciation expense) in the calculation of rate base. Please provide rationale supporting the current approach.

d) In the context of the manner that Toronto Hydro calculates depreciation expense, it seems that monthly forecast PP&E NBV data is available (Exhibit 4B / Tab 1 / Schedule 1 / pp. 2-3). Please advise whether this is true.

e) If monthly data is available, please provide Toronto Hydro's position on using the monthly data to calculate its annual rate base amounts for the 2020-2024 period.

f) Please provide the rate base amounts (including supporting documentation) for the 2020-2024 period that is based on using monthly data for the calculation of both capital additions and depreciation.

g) Please provide the rate base amounts (including supporting documentation) for the 2020-2024 period that is based on Toronto Hydro's current approach for including capital in-service additions in rate base but instead applying the half-year rule in the calculation of depreciation expense.

RESPONSE:

a) Toronto Hydro follows the OEB prescribed methodology to calculate the rate base.[1] The effect of this method is to include the sum of the annual in-service additions to the closing PP&E balance used to determine the rate base.

b) Except for derecognition,[2] Toronto Hydro calculates depreciation expense monthly based on when the assets come into service. Consistent with the OEB prescribed methodology noted above, depreciation expense for a given year is added to the closing PP&E NBV balance, which is then used in the average rate base calculation.

c) Toronto Hydro's approach to calculate rate base is consistent with the OEB prescribed methodology as noted above.

d) Yes, monthly forecast PP&E NBV data is available.

e) Please see response to part (c).

f) Please refer to Appendix A to this response for the monthly data and annual rate base amounts for the 2020-2024 CIR term. Supporting information related to the amounts forming part of rate base is included in Exhibit 2A, Tab 1, Schedule 1.

g) Please see table below for the rate base amounts resulting from the application of the half-year rule to calculate depreciation (i.e. depreciation at mid-year in the first year

[1] 2006 Electricity Distribution Rate Handbook, Section 4.0, on page 25.
[2] Please refer to Toronto Hydro's response to interrogatory 9-Staff-156 (d) for the process for forecasting derecognition, which is also part of depreciation expenses.

of assets placed into service).

Table 1: Rate Base Amounts

	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Opening PP&E NBV	4,270.4	4,488.6	4,686.8	4,979.1	5,257.5
Closing PP&E NBV	4,488.6	4,686.8	4,979.1	5,257.5	5,513.8
Average PP&E NBV	**4,379.5**	**4,587.7**	**4,832.9**	**5,118.3**	**5,385.7**
Working Capital Allowance	235.2	239.1	243.6	248.2	254.0
Rate Base	**4,614.7**	**4,826.8**	**5,076.6**	**5,366.6**	**5,639.6**

Appendix A: 2020-2024 Ratebase

in $ Millions	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Rate Base	
Opening NBV[1]	4,270.4	4,275.2	4,282.8	4,297.9	4,303.1	4,310.9	4,321.4	4,331.6	4,338.1	4,353.4	4,367.1	4,394.3	4,270.4	a
In Service Additions[2]	24.7	28.1	36.3	26.7	30.0	32.8	31.7	29.5	38.2	37.1	51.1	123.8	489.8	b
Depreciation (excluding allocated transportaion depreciation)[3]	- 20	- 21	- 21	- 22	- 22	- 22	- 21	- 23	- 23	- 23	- 24	- 28	- 270	c
Closing NBV[1]	4,275.2	4,282.8	4,297.9	4,303.1	4,310.9	4,321.4	4,331.6	4,338.1	4,353.4	4,367.1	4,394.3	4,489.8	4,489.8	d=a+b+c
Average NBV	**4,272.8**	**4,279.0**	**4,290.4**	**4,300.5**	**4,307.0**	**4,316.2**	**4,326.5**	**4,334.9**	**4,345.7**	**4,360.2**	**4,380.7**	**4,442.1**	**4,380.1**	e=(a+d)/2
WCA[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**235.2**	f
Rate Base[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**4,615.3**	g=e+f

in $ Millions	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Rate Base	
Opening NBV[1]	4,489.8	4,487.6	4,491.5	4,498.6	4,500.7	4,506.3	4,514.1	4,521.4	4,537.7	4,551.5	4,564.0	4,588.3	4,489.8	a
In Service Additions[2]	19.0	25.7	29.5	25.0	29.1	31.4	29.7	40.3	37.6	36.7	48.8	131.0	483.7	b
Depreciation (excluding allocated transportaion depreciation)[3]	- 21	- 22	- 22	- 23	- 23	- 24	- 22	- 24	- 24	- 24	- 25	- 29	- 284	c
Closing NBV[1]	4,487.6	4,491.5	4,498.6	4,500.7	4,506.3	4,514.1	4,521.4	4,537.7	4,551.5	4,564.0	4,588.3	4,689.9	4,689.9	d=a+b+c
Average NBV	**4,488.7**	**4,489.6**	**4,495.0**	**4,499.6**	**4,503.5**	**4,510.2**	**4,517.8**	**4,529.6**	**4,544.6**	**4,557.8**	**4,576.2**	**4,639.1**	**4,589.9**	e=(a+d)/2
WCA[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**239.1**	f
Rate Base[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**4,828.9**	g=e+f

in $ Millions	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Rate Base	
Opening NBV[1]	4,689.9	4,690.2	4,696.7	4,706.7	4,711.6	4,719.4	4,730.0	4,739.4	4,745.6	4,758.7	4,772.9	4,825.0	4,689.9	a
In Service Additions[2]	22.1	29.1	33.1	28.4	31.9	34.9	32.8	31.2	38.1	39.5	78.1	191.7	590.9	b
Depreciation (excluding allocated transportaion depreciation)[3]	- 22	- 23	- 23	- 24	- 24	- 24	- 23	- 25	- 25	- 25	- 26	- 31	- 295	c
Closing NBV[1]	4,690.2	4,696.7	4,706.7	4,711.6	4,719.4	4,730.0	4,739.4	4,745.6	4,758.7	4,772.9	4,825.0	4,986.1	4,986.1	d=a+b+c
Average NBV	**4,690.0**	**4,693.4**	**4,701.7**	**4,709.1**	**4,715.5**	**4,724.7**	**4,734.7**	**4,742.5**	**4,752.1**	**4,765.8**	**4,798.9**	**4,905.5**	**4,838.0**	e=(a+d)/2
WCA[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**243.6**	f
Rate Base[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**5,081.6**	g=e+f

in $ Millions	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Rate Base	
Opening NBV[1]	4,986.1	4,990.3	5,001.3	5,016.0	5,024.8	5,036.1	5,051.1	5,065.3	5,075.6	5,093.2	5,112.0	5,145.2	4,986.1	a
In Service Additions[2]	27.3	34.7	39.2	33.7	36.9	40.8	39.1	37.0	44.2	45.7	60.7	153.7	593.0	b
Depreciation (excluding allocated transportaion depreciation)[3]	- 23	- 24	- 24	- 25	- 26	- 26	- 25	- 27	- 27	- 27	- 28	- 32	- 313	c
Closing NBV[1]	4,990.3	5,001.3	5,016.0	5,024.8	5,036.1	5,051.1	5,065.3	5,075.6	5,093.2	5,112.0	5,145.2	5,266.5	5,266.4	d=a+b+c
Average NBV	**4,988.2**	**4,995.8**	**5,008.6**	**5,020.4**	**5,030.4**	**5,043.6**	**5,058.2**	**5,070.5**	**5,084.4**	**5,102.6**	**5,128.6**	**5,205.8**	**5,126.3**	e=(a+d)/2
WCA[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**248.2**	f
Rate Base[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**5,374.5**	g=e+f

in $ Millions	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Rate Base	
Opening NBV[1]	5,266.5	5,268.0	5,276.5	5,288.7	5,294.9	5,303.7	5,317.1	5,328.3	5,336.6	5,351.7	5,368.2	5,399.3	5,266.5	a
In Service Additions[2]	25.8	33.4	37.8	32.3	35.7	40.3	37.3	36.1	42.9	44.7	59.9	159.9	586.1	b
Depreciation (excluding allocated transportaion depreciation)[3]	- 24	- 25	- 26	- 26	- 27	- 27	- 26	- 28	- 28	- 28	- 29	- 34	- 327	c
Closing NBV[1]	5,268.0	5,276.5	5,288.7	5,294.9	5,303.7	5,317.1	5,328.3	5,336.6	5,351.7	5,368.2	5,399.3	5,525.5	5,525.5	d=a+b+c
Average NBV	**5,267.2**	**5,272.2**	**5,282.6**	**5,291.8**	**5,299.3**	**5,310.4**	**5,322.7**	**5,332.5**	**5,344.2**	**5,360.0**	**5,383.8**	**5,462.4**	**5,396.0**	e=(a+d)/2
WCA[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**254.0**	f
Rate Base[1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**5,650.0**	g=e+f

[1]EB-2018-0165, Exhibit 2A, Tab 1, Schedule 1, Table 1
[2]EB-2018-0165, Exhibit 2A, Tab 1, Schedule 2
[3]EB-2018-0165, Exhibit 4B, Tab 1, Appendix A

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.1:

Reference(s): 2A-Staff-52 (g)

To provide the depreciation expense associated with the rate base calculation provided in response to part g of 2A-Staff-52.

RESPONSE:

Table 1 below show the depreciation expense for 2020 to 2024 using the half-year approach, which was calculated for the purpose of the response to interrogatory 2A-Staff-52 (g). Toronto Hydro notes that using this approach results in a depreciation expense that is $11.7 million higher than what the utility has forecasted in its application.

Table 1: 2020-2024 Depreciation Expense using Half-Year Approach ($ Millions)

in $millions	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Depreciation	245.8	258.7	271.8	286.3	301.5
Derecognition	25.8	27.0	26.9	28.3	28.5
Total Depreciation	271.6	285.7	298.6	314.6	329.9
Less: *Fully Allocated Depreciation*					
Transportation	(1.8)	(1.8)	(1.8)	(1.8)	(1.8)
Net Depreciation	269.8	283.9	296.9	312.8	328.2

Toronto Hydro's historical depreciation expense is based on detailed calculations within its ERP (financial) system of monthly in-service additions, as presented in the response to interrogatory 4B-Staff-139 (c). Toronto Hydro uses the same approach to forecast depreciation, and believes that being aligned with the historical practice provides a more accurate forecast of depreciation expense than the half-year rule approach.

As indicated in the response to interrogatory 2A-Staff-52 part (a), Toronto Hydro's approach to calculating rate base takes an average of the opening and closing balances for gross fixed assets and accumulated depreciation. This approach is consistent with the 2006 Electricity Distributor Handbook,[1] the 2017 Filing Requirements[2], and the OEB's Revenue Requirement Work Forms.[3] Furthermore, the approach reflects an annual calculation rather than a monthly analysis, which aligns with the purpose of calculating rate base to determine the utility's annual return on its investments.

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[1] 2006 Electricity Distributor Handbook: Section 4.0, page 25.

[2] Filing Requirements For Electricity Distribution Rate Applications-2017 Edition for 2018 Rate Applications: Chapter 2, Exhibit 2, page 15.

[3] Filing Requirements For Electricity Distribution Rate Applications-2017 Edition for 2018 Rate Applications: Chapter 2, Exhibit 6, page 45.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME: **Technical Conference**

DATE: **February 19, 2019**

MR. GLUCK: Do you have that in front of you? Okay.

So my question for you is, can you confirm that the amounts set out in the spreadsheet that I provided use the information provided in Appendix A to 2A-Staff-52 to correctly calculate Toronto Hydro's rate base on an average of monthly averages basis?

MR. MUNDENCHIRA: Yes. The numbers are correct.

MR. GLUCK: Thank you. Does Toronto Hydro believe that this is a more accurate estimate of rate base in a given year as it relies on the best available forecast of both in-service additions and depreciation?

MR. MUNDENCHIRA: I would like to point to our response -- in my response here. So for the same interrogatory, 2A-Staff-52, we have described why we have used the approach we have used, and as such we believe the proposed approach is not the most appropriate.

MR. GLUCK: Are you referring to -- which part of the IR response are you referring to?

MR. MUNDENCHIRA: 2A-Staff-52A, sub-question A.

MR. GLUCK: Okay. So you are relying on the 2006 Electricity Rate Handbook as why this approach that you are using is more appropriate than the monthly average approach?

MR. GARNER: Sorry, just for the record can either one of you identify the distinction between the two approaches just so we can...

MR. GLUCK: Sure. Maybe you could describe your approach, and then I will describe the staff approach.

MR. MUNDENCHIRA: Sure, I can do that. So the approach we have used is in addition to the 2006 filing requirements, also in the 2017 filing requirements for 2017 rate applications. I don't have the exact reference in front of me. The same methodology was described.

So to explain it, it would be taking the opening rate base for the year, plus the closing rate base and divided by two, to calculate the rate base that would be used in the revenue requirement calculation.

MR. GARNER: We are talking the distinction here is just about using monthly averages versus year-end opening and closing averages?

MR. MUNDENCHIRA: Yes.

MR. GARNER: Thank you.

MR. GLUCK: Okay. So it is based on the 2006 handbook and also the 2017 handbook. And you are aware that the 2017 handbook does describe the option of using a monthly average approach?

Like, we could open it up or you can -- maybe it is helpful to open it up.

MR. MUNDENCHIRA: I don't have it in front of me, so I am not familiar.

MR. GLUCK: Maybe I could read it.

> "If an applicant uses an alternative method such as calculating the average in-service fixed assets based on the average of monthly or quarterly values, it must document the methodology used."

So it sort of speaks to the ability that there is an alternative that utilities could use, if appropriate.

MR. KEIZER: Is there a question, Mr. Gluck --

MR. GLUCK: No.

MR. KEIZER: -- other than that is what the handbook says?

MR. GLUCK: That is what the handbook says. I am just confirming that Toronto Hydro is aware that that is part of the handbook as well.

MR. KEIZER: I don't know if we want to argue about what the wording of the handbook is, although it does seem to imply if the applicant chooses to do so, which the applicant in this case has not chosen to do so.

MR. GLUCK: That's fair. Can I ask a question about why the in-service additions are so weighted towards the end of the year?

MR. MUNDENCHIRA: For this question, if I can point you to our response to -- interrogatory response 2A-SEC-31, SEC 31?

MR. GLUCK: Okay.

MR. MUNDENCHIRA: So if you go to page 2 of the response, and if you look at the lines at line 3 and line 7 -- especially in line 7, we describe the methodology that we use for forecasting in-service additions. And at lines 10, 11 and 12 specifically, it mentions that we look at historical rates of in-service additions to come up with the best estimate of how it has been in the prior years, and that is the methodology we use for forecasting.

MR. GLUCK: So if we were to go back in time, it would look for, you know, 2010 -- whatever year, 2013 to 2018, it would look like the majority of your asset in-service date is November and December, going back in time.

So going forward you're forecasting on the same basis as what has actually happened in the past. Is that correct?

MR. MUNDENCHIRA: Yes.

MR. GLUCK: And why would that be the case, that your assets on an actual basis historically go into service largely in November and December in a given year?

[Witness panel confers]

MR. TRGACHEF: So typically, when you review our construction cycle throughout the year, typically our construction does start winter-spring and carries out towards the end of the year.

It is heavily weighted to summer/fall seasons and with that, the completions typically take place late fall or November, early winter.

So we do have seasonality that we deal with, and that's when our in-service additions and projects are completed and attained. That's why you are seeing the rear end build up near the end of the year.

MR. GLUCK: Okay, thank you. So part G of 2A-Staff-52; I was hoping that you could take an undertaking to provide me with the depreciation expense for each year that's associated with the half-year rule calculation that you provided in response to that question.

Exhibit KTC 1.1

in $ Millions	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Applied Rate Base	Average of Monthly Average RB	RB Var
Opening NBV1	4,270.4	4,275.2	4,282.8	4,297.9	4,303.1	4,310.9	4,321.4	4,331.6	4,338.1	4,353.4	4,367.1	4,394.3	4,270.4		
In Service Additions2	24.7	28.1	36.3	26.7	30.0	32.8	31.7	29.5	38.2	37.1	51.1	123.8	489.8		
Depreciation (excluding allocated transportaion depreciation)3	- 20	- 21	- 21	- 22	- 22	- 22	- 21	- 23	- 23	- 23	- 24	- 28	- 270		
Closing NBV1	4,275.2	4,282.8	4,297.9	4,303.1	4,310.9	4,321.4	4,331.6	4,338.1	4,353.4	4,367.1	4,394.3	4,489.8	4,489.8		
Average NBV	4,272.8	4,279.0	4,290.4	4,300.5	4,307.0	4,316.2	4,326.5	4,334.9	4,345.7	4,360.2	4,380.7	4,442.1	4,380.1	$ 4,329.67	$ (50.43)
WCA1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	235.2	$ 235.20	
Rate Base1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	4,615.3	$ 4,564.87	$ (50.43)

in $ Millions	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Applied Rate Base	Average of Monthly Average RB	RB Var
Opening NBV1	4,489.8	4,487.6	4,491.5	4,498.6	4,500.7	4,506.3	4,514.1	4,521.4	4,537.7	4,551.5	4,564.0	4,588.3	4,489.8		
In Service Additions2	19.0	25.7	29.5	25.0	29.1	31.4	29.7	40.3	37.6	36.7	48.8	131.0	483.7		
Depreciation (excluding allocated transportaion depreciation)3	- 21	- 22	- 22	- 23	- 23	- 24	- 22	- 24	- 24	- 24	- 25	- 29	- 284		
Closing NBV1	4,487.6	4,491.5	4,498.6	4,500.7	4,506.3	4,514.1	4,521.4	4,537.7	4,551.5	4,564.0	4,588.3	4,689.9	4,689.9		
Average NBV	4,488.7	4,489.6	4,495.0	4,499.6	4,503.5	4,510.2	4,517.8	4,529.6	4,544.6	4,557.8	4,576.2	4,639.1	4,589.9	$ 4,529.31	$ (60.59)
WCA1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	239.1	$ 239.10	
Rate Base1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	4,828.9	$ 4,768.41	$ (60.49)

in $ Millions	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Applied Rate Base	Average of Monthly Average RB	RB Var
Opening NBV1	4,689.9	4,690.2	4,696.7	4,706.7	4,711.6	4,719.4	4,730.0	4,739.4	4,745.6	4,758.7	4,772.9	4,825.0	4,689.9		
In Service Additions2	22.1	29.1	33.1	28.4	31.9	34.9	32.8	31.2	38.1	39.5	78.1	191.7	590.9		
Depreciation (excluding allocated transportaion depreciation)3	- 22	- 23	- 23	- 24	- 24	- 24	- 23	- 25	- 25	- 25	- 26	- 31	- 295		
Closing NBV1	4,690.2	4,696.7	4,706.7	4,711.6	4,719.4	4,730.0	4,739.4	4,745.6	4,758.7	4,772.9	4,825.0	4,986.1	4,986.1		
Average NBV	4,690.0	4,693.4	4,701.7	4,709.1	4,715.5	4,724.7	4,734.7	4,742.5	4,752.1	4,765.8	4,798.9	4,905.5	4,838.0	$ 4,744.49	$ (93.51)
WCA1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	243.6	$ 243.60	
Rate Base1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	5,081.6	$ 4,988.09	$ (93.51)

in $ Millions	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Applied Rate Base	Average of Monthly Average RB	RB Var
Opening NBV1	4,986.1	4,990.3	5,001.3	5,016.0	5,024.8	5,036.1	5,051.1	5,065.3	5,075.6	5,093.2	5,112.0	5,145.2	4,986.1		
In Service Additions2	27.3	34.7	39.2	33.7	36.9	40.8	39.1	37.0	44.2	45.7	60.7	153.7	593.0		
Depreciation (excluding allocated transportaion depreciation)3	- 23	- 24	- 24	- 25	- 26	- 26	- 25	- 27	- 27	- 27	- 28	- 32	- 313		
Closing NBV1	4,990.3	5,001.3	5,016.0	5,024.8	5,036.1	5,051.1	5,065.3	5,075.6	5,093.2	5,112.0	5,145.2	5,266.5	5,266.4		
Average NBV	4,988.2	4,995.8	5,008.6	5,020.4	5,030.4	5,043.6	5,058.2	5,070.5	5,084.4	5,102.6	5,128.6	5,205.8	5,126.3	$ 5,061.43	$ (64.88)
WCA1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	248.2	$ 248.20	
Rate Base1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	5,374.5	$ 5,309.63	$ (64.88)

in $ Millions	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Applied Rate Base	Average of Monthly Average RB	RB Var
Opening NBV1	5,266.5	5,268.0	5,276.5	5,288.7	5,294.9	5,303.7	5,317.1	5,328.3	5,336.6	5,351.7	5,368.2	5,399.3	5,266.5		
In Service Additions2	25.8	33.4	37.8	32.3	35.7	40.3	37.3	36.1	42.9	44.7	59.9	159.9	586.1		
Depreciation (excluding allocated transportaion depreciation)3	- 24	- 25	- 26	- 26	- 27	- 27	- 26	- 28	- 28	- 28	- 29	- 34	- 327		
Closing NBV1	5,268.0	5,276.5	5,288.7	5,294.9	5,303.7	5,317.1	5,328.3	5,336.6	5,351.7	5,368.2	5,399.3	5,525.5	5,525.5		
Average NBV	5,267.2	5,272.2	5,282.6	5,291.8	5,299.3	5,310.4	5,322.7	5,332.5	5,344.2	5,360.0	5,383.8	5,462.4	5,396.0	$ 5,327.43	$ (68.57)
WCA1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	254.0	$ 254.00	
Rate Base1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	5,650.0	$ 5,581.43	$ (68.57)

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Filing Requirements For
Electricity Distribution Rate Applications
- 2018 Edition for 2019 Rate Applications -

Chapter 2

Cost of Service

July 12, 2018

Distributors should note that the requirement to file a distribution system plan every five years still applies even if a consolidation application has been filed or approved.

2.2 Exhibit 2: Rate Base

This exhibit includes information on rate base, capital expenditures and service quality.

2.2.1 Rate Base

This exhibit must include the following sections:

1) Overview
2) Gross Assets – Property, Plant and Equipment (PP&E) and Accumulated Depreciation
3) Allowance for Working Capital

2.2.1.1 Overview

The information outlined in Appendix 2-BA must be provided for each year, in both the application document and in working Microsoft Excel format.

For rate base, the applicant must include the opening and closing balances for each year, and the average of the opening and closing balances for gross fixed assets and accumulated depreciation. If an applicant uses an alternative method, such as calculating the average in-service fixed assets based on the average of monthly or quarterly values, it must document the methodology used. Rate base may also include an allowance for working capital (described below).

At a minimum, the information filed in support of the requested rate base must include data for the historical actuals, bridge year (actuals to date and balance of year as budgeted), and test year. Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include interest during construction and all overheads. Written explanations must be provided where there is a year-over-year variance greater than the applicable materiality threshold.

If continuity statements have been restated for the purposes of the application (e.g. changes in accounting standards or to reflect corrections in historical audited values), the utility must provide a thorough explanation for the restatement and also provide a reconciliation to the original statements.

The following comparisons must be provided:

TAB 10

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC1.4:

Reference(s): 2B-Staff-75

To provide an illustrative example of how capital expenditures are translated into in-service additions.

RESPONSE:

The process of converting capital expenditures to in-service additions consists of the steps described below, which are illustrated in Appendix A using a metering investment example. Appendix A also illustrates how a reduction to capital expenditures for the metering program would be flowed through to the in-service additions forecast.

1. Toronto Hydro first determines the percentage of capital expenditures expected to go in-service in a given year. It makes this determination in one of two ways:

    a) For distribution capital programs,[1] it applies a conversion factor to the forecasted capital expenditures to determine the expected in-service additions resulting from those capital expenditures. The conversion factor is derived using a historical four year average[2] ratio of actual distribution capital expenditures to actual in-service additions.

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[1] Distribution capital programs refers to programs in the System Access, System Renewal, and System Service investment categories.
[2] For the purpose of this application, the four year average was based on 2013 to 2016 actuals.

b) Where there is specific information available about the completion timeline for a particular capital project or program (e.g. major projects like Copeland TS and general plant programs like Fleet, Facilities and Information Technology), that information is used to forecast the in-service additions associated with that project or program.

2. Toronto Hydro then allocates the forecasted in-service additions to specific asset classes in its fixed asset ledger. It performs this allocation in one of two ways:

   a) For distribution capital programs, it applies historical assumptions about: i) which assets are generated by each program and ii) how the in-service dollars for the program should be allocated to those asset classes. The calculation to determine what percentage of the program's in-service additions are allocated to program's asset classes is based on a two year historical average[3] ratio of actual in-service additions in the program by asset class.

   b) Where there is specific information available about the assets being put in-service by a particular project or program (i.e. major projects like Copeland TS and general plant programs like Fleet, Facilities and Information Technology), that information is used to forecast the in-service additions by asset class for that project or program.

[3] For the purpose of this application, the two year average was based on 2015 and 2016 actuals.

For the purpose of forecasting the total in-service additions for a particular year, Toronto Hydro also applies a similar two step approach to its opening Construction Work in Progress (CWIP) balance. The steps are explained below and illustrated in Appendix A.

1. Toronto Hydro first determines what percentage of the opening CWIP balance is expected to go in-service in a particular year. It makes this determination in one of two ways:

    a) For distribution capital programs, it applies a conversion factor to the opening CWIP balance to calculate the forecasted in-service additions expected to result from the opening CWIP balance. The conversion factor is calculated using a four year historical average[4] ratio of actual CWIP to actual in-service additions.

    b) Where a CWIP amount can be tied to a particular capital project or program (i.e. major projects like Copeland TS and general plant programs like Fleet, Facilities, and Information Technology) that has a specific completion timeline, this information is used to forecast the in-service additions that can be expected to result from the CWIP amount.

2. Toronto Hydro then allocates the forecasted in-service additions resulting from the opening CWIP balance to specific asset classes. It performs this allocation in one of two ways:

[4] For the purpose of this application, the four year average was based on 2013 to 2016 actuals.

a) For distribution capital CWIP, Toronto Hydro applies historical assumptions: i) which assets are generated by distribution capital and ii) how the in-service dollars for distribution capital should be allocated to those asset classes. The calculation to determine what percentage of the distribution CWIP is allocated to the respective assets class is based on a two year historical average[5] ratio of actual in-service additions by asset class.

b) Where a CWIP amount can be tied to a particular capital project or program (e.g. Copeland or general plant programs), and there is specific information available about the assets that are being put in-service as part of project or program, that information is used to forecast the in-service additions by asset class for that project or program.

[5] For the purpose of this application, the two year average was based on 2015 and 2016 actuals.

ISA Illustration on System Access, System Renewal & System Service Capital Expenditures in 2020 (in $ Millions)

				Application			10% Capex Reduction Scenario[3]		
				A	B	C = A x B	A	B	C = A x B
Program	OEB Account	Description	Asset Class % of Capital Expenditures[2]	2020 Capex $	Capex Conversion %[1]	2020 ISA $	2020 Capex $ (-10%)	Capex Conversion %	2020 ISA $
Metering	1611	Computer Software (Formally known as Account 1925)	4%	$ 0.8	57%	$ 0.4	$ 0.7	57%	$ 0.4
Metering	1820	Distribution Station Equipment <50 kV	13%	$ 2.6	57%	$ 1.5	$ 2.4	57%	$ 1.4
Metering	1830	Poles, Towers & Fixtures	0%	$ 0.0	57%	$ 0.0	$ 0.0	57%	$ 0.0
Metering	1840	Underground Conduit	0%	$ 0.0	57%	$ 0.0	$ 0.0	57%	$ 0.0
Metering	1845	Underground Conductors & Devices	0%	$ 0.0	57%	$ 0.0	$ 0.0	57%	$ 0.0
Metering	1860	Meters	83%	$ 16.8	57%	$ 9.6	$ 15.1	57%	$ 8.6
Metering	1920	Computer Equipment - Hardware	0%	$ 0.1	57%	$ 0.1	$ 0.1	57%	$ 0.1
Metering	1945	Measurement & Testing Equipment	0%	$ 0.0	57%	$ 0.0	$ 0.0	57%	$ 0.0
Total			100%	$ 20.3	57%	$ 11.6	$ 18.3	57%	$ 10.5

Steps for Capital Expenditure Conversions to ISA:

[1]Conversion rate from historical ISA on current year capital expenditures for System Access/Service/Renewal investments with the exception of major projects.

[2]Allocation to Asset Classes based on historical assets generated for the program is used for System Access/Service/Renewal investments with the exception of major projects.

[3]Example of implication of a 10% reduction to capital, reducing capital expenditures in 2020.

ISA Illustration on Opening CWIP for System Access, System Renewal & System Service (in $ Millions)

	A	B	C = A x B
Categories	2020 Opening CWIP $	CWIP Conversion %[4]	Opening CWIP ISA $
System Access, System Renewal, System Service	$ 223.1	64%	$ 142.3

Opening CWIP ISA Details by Asset Class ($Millions)			Asset Class % of CWIP[5]	ISA $
	OEB Account	Description		
System Access, System Renewal & System Service[1]	1611	Computer Software (Formally known as Account 1925)	0.3%	$ 0.4
	1808	Buildings	0.1%	$ 0.1
	1815	Transformer Station Equipment >50 kV	0.0%	$ 0.0
	1820	Distribution Station Equipment <50 kV	5.3%	$ 7.5
	1830	Poles, Towers & Fixtures	7.3%	$ 10.4
	1835	Overhead Conductors & Devices	11.3%	$ 16.1
	1840	Underground Conduit	27.5%	$ 39.2
	1845	Underground Conductors & Devices	23.6%	$ 33.6
	1850	Line Transformers	18.6%	$ 26.5
	1855	Services (Overhead & Underground)	4.8%	$ 6.8
	1860	Meters	7.7%	$ 11.0
	1920	Computer Equipment - Hardware	0.0%	$ 0.0
	1940	Tools, Shop & Garage Equipment	0.3%	$ 0.5
	1945	Measurement & Testing Equipment	0.0%	$ 0.0
	1955	Communications Equipment	0.2%	$ 0.2
	1980	System Supervisor Equipment	1.8%	$ 2.6
	2440	Contributions & Grants (Formally known as Account 1995)	-8.9%	$ (12.7)
	Grand Total		100.0%	$ 142.3

Steps for CWIP to ISA:

[4]Conversion rate from historical ISA on Opening CWIP for System Access/Service/Renewal investments with the exception of major projects.

[5]Allocation to Asset Classes based on historical assets generated for the System Access/Service/Renewal category investments with the exception of major projects.

Note: Above is an illustration of the ISA calculation for a sub-set of the Capital Program

Toronto Hydro's 2020 rate base forecast is unchanged. The utility estimates that the impact of rate base variances in 2018 and 2019 on the forecast Net Fixed Assets component of 2020 opening rate base will be less than one percent. As discussed in Section 3 below, Toronto Hydro proposes to update its 2020 working capital allowance ("WCA") during the rate order process in this proceeding.

1.1 In-Service Additions ("ISAs") and Construction Work in Progress ("CWIP") Update

Appendix A to this schedule provides an update to Toronto Hydro's response to 2B-Staff-75, part (a) (ii). The utility projects its net total five-year in-service additions to be about one percent greater than the forecast amount which formed the basis of Toronto Hydro's approved capital-related revenue requirement for the 2015-2019 period.

Table 2 provides an update to CWIP values for the 2015-2019 period.

Table 2: 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	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

1.2 Fixed Asset Continuity Statements

The continuity statements (OEB Appendix 2-BA) are filed at Exhibit U, Tab 1, Schedule 1, Appendix B.

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2015-2018 Average	2019 Bridge	2020 Forecast
Opening CWIP	$ 522.10	$ 577.70	$ 502.90	$ 485.80	$ 522.13	$ 396.40	$ 381.10
Additions (CAPEX)	$ 490.60	$ 508.40	$ 496.60	$ 434.90	$ 482.63	$ 425.30	$ 517.20
Total	$ 1,012.70	$ 1,086.10	$ 999.50	$ 920.70	$1,004.75	$ 821.70	$ 898.30
Deductions (In Service Additions)	$ (435.30)	$ (584.30)	$ (520.30)	$ (524.40)	$ (516.08)	$ (440.60)	$ (539.90)
Conversion Factor	-42.98%	-53.80%	-52.06%	-56.96%	-51.36%	-53.62%	-60.10%

Ref:
U-Staff-168 / Appendix B / p. 9

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

UNDERTAKING NO. JTC3.1:

Reference(s):

Preamble:

So the first is just to address Board Staff's request to deal with ISAs by program. So currently Toronto Hydro does not do -- or does not create a forecast of ISAs by program, but for the two Board Staff's requests, what Toronto Hydro is prepared to do is to consider whether it can, and to the extent it can it will provide something. To the extent it cannot, it would describe as to why it cannot.

For the two board staff's requests to deal with ISAS by program, to consider whether it can, and to the extent it can it will provide something. To the extent it cannot, it would describe as to why it cannot.

RESPONSE:

Appendix A to this response includes the 2020-2024 forecasted in-service additions by program, as requested by Board Staff. Toronto Hydro's response to undertaking JTC1.4 provides a detailed explanation of Toronto Hydro's forecasting methodology for in-service additions.

As mentioned in the response to interrogatory 2A-SEC-31, Toronto Hydro's methodology generates forecasts of in-service additions by asset class as this information is necessary for financial and rate-making purposes to determine rate base and depreciation for the revenue requirement calculation. In applying this methodology to derive in-service additions by program, Toronto Hydro had to make certain assumptions and accept certain limitations which may undermine the veracity of these forecasts. The assumptions and limitations are described below.

1. Toronto Hydro applied historical conversion ratios of capital expenditures to in-service dollars to the programs, as described in the response to undertaking JTC1.4. The limitation of this approach is that the historical conversion rates are based on aggregate values for distribution capital, and may not be entirely aligned with program level assumptions (e.g. the amount of work to be completed in a particular year and project-specific characteristics such as size, complexity, and external factors that may influence project durations, and ultimately in-service additions).

2. Toronto Hydro allocated a portion of the opening CWIP balance related to distribution capital, to programs using the general assumption that the percentage of CWIP allocated to each distribution capital program would be the same as the percentage of total distribution capital expenditures by program based on the last three years of actuals (2015-2017). To illustrate, if Overhead Program was on average 20 percent of the total distribution capital expenditures plan over the 2015-2017 period, Toronto Hydro assumed that 20 percent of the 2018 distribution capital opening CWIP would be allocated to the Overhead Program. The limitation of this approach is that the CWIP balances may not necessarily have the same relationship to the programs as the capital expenditures because certain programs include projects that have longer durations and may be closer or further from completion, than others.

3. Once the CWIP was allocated to the programs, Toronto Hydro applied historical conversion rates to the CWIP balances to calculate the amount of CWIP that could be expected to come in-service in each program. As mentioned above, the limitation of this approach is that the historical conversion rates are based on aggregate values for distribution capital, and may not be entirely aligned with program level assumptions (e.g. the amount of carry-over work expected).

4. Where Toronto Hydro had specific information available about the completion timeline for a particular program or project (e.g. Copeland TS – Phase 2 or general plant programs), this information was directly reflected in the in-service additions forecast for the applicable program (e.g. Stations Expansion, Fleet, Facilities, Information Technology).

OEB In Service Addition
Capital Programs Table

Programs ($M)	2020	2021	2022	2023	2024
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer Connections Gross	73.5	77.2	79.1	81.8	83.8
Customer Connections Capital Contribution	(33.4)	(34.4)	(34.8)	(36.3)	(37.4)
Externally Initiated Plant Relocations & Expansion Gross	51.8	36.4	15.8	13.1	196.2
Externally Initiated Plant Relocations & Expansion Capital Contribution	(35.4)	(17.6)	(11.5)	(8.8)	(187.3)
Generation Protection, Monitoring, and Control	3.4	2.3	2.4	2.5	2.7
Load Demand	15.1	12.8	16.0	20.1	22.4
Metering	22.0	19.8	19.5	28.0	34.6
System Access Total	**97.1**	**96.4**	**86.6**	**100.4**	**115.1**
Area Conversions	42.1	45.1	46.1	48.8	41.6
Network System Renewal	21.7	20.2	19.2	18.4	18.4
Reactive and Corrective Capital	60.4	61.7	63.0	64.2	65.5
Stations Renewal	22.0	26.6	31.4	32.8	25.5
Underground System Renewal - Downtown	8.7	17.1	21.4	26.7	29.3
Underground System Renewal - Horseshoe	84.7	87.9	89.7	92.2	94.6
Overhead Infrastructure Relocation	0.2	0.1	0.0	0.0	0.0
SCADAMATE R1 Renewal	1.1	0.4	0.1	0.1	0.0
PILC Piece Outs & Leakers	0.7	0.3	0.1	0.0	0.0
Underground Legacy Infrastructure	2.2	0.8	0.3	0.1	0.0
Overhead System Renewal	38.3	46.2	49.6	53.9	56.6
System Renewal Total	**282.1**	**306.2**	**321.0**	**337.1**	**331.6**
Energy Storage Systems Gross	6.8	17.2	26.8	-	-
Energy Storage Systems Capital Contribution[1]	(6.6)	(14.7)	(21.0)	-	-
Network Condition Monitoring and Control	4.3	7.9	10.8	13.6	16.0
Overhead Momentary Reduction	-	-	-	-	-
Stations Expansion	50.4	4.0	27.3	64.9	44.6
Stations Expansion Capital Contribution	-	-	-	-	-
System Enhancements	6.6	6.3	5.9	5.3	5.1
Handwell Upgrades	0.1	0.0	0.0	0.0	0.0
Polymer SMD-20 Renewal	0.1	0.0	0.0	0.0	0.0
Design Enhancement	0.0	0.0	0.0	0.0	0.0
System Service Total	**61.9**	**20.8**	**49.8**	**83.8**	**65.7**
Facilities Management and Security	5.9	10.3	14.6	12.7	13.4
Fleet and Equipment	4.7	8.2	7.8	8.4	8.7
IT/OT Systems	40.1	43.5	72.8	52.0	53.3
Control Operations Reinforcement	-	-	41.2	-	-
Operating Centers Consolidation Plan	-	-	-	-	-
Program Support	-	-	-	-	-
General Plant Total	**50.7**	**62.1**	**136.4**	**73.1**	**75.4**
AFUDC					
Miscellaneous	1.6	1.3	1.1	1.0	1.0
Miscellaneous Capital Contribution					
Other Total	**1.6**	**1.3**	**1.1**	**1.0**	**1.0**
Subtotal	**493.3**	**486.8**	**594.9**	**595.4**	**588.7**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)[1]	(3.5)	(3.0)	(3.9)	(2.4)	(2.5)
Total	**489.8**	**483.8**	**591.0**	**593.0**	**586.2**

[1]The presentation of the capital contributions for Energy Storage Systems in Exhibit 2A, Tab 1, Schedule 2 and 1B-Staff-22 incorrectly presented the Customer Specific ESS (Exhibit 2B-Section E7.2, Table 19) as being exluded from rate base by deduction under the Renewable Generation Facilitiy Assets and Other Non Rate-Regulated Utility Assets line so as to exclude from rate base. Above shcedule shows capital contributions being applied to these costs, rather than being removed from rate base at the bottom line, which is the appropriate presentation, even though the rate base amount is the same in both cases. Updated Fixed Asset Continuity Schedules will be filed as part of the update.

TAB 11

In-Service Additions for the 2015-2019 Period

	Historical												Bridge			Historical/Bridge		
	2015			2016			2017			2018			2019			2015-2019		
In-Service Additions	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Forecast**	**Var.**	**CIR Filing (-10%)**	**Actual / Forecast**	**Var.**
Gross	526.8	465.4	-12%	635.6	617.1	-3%	474.4	549.0	16%	413.2	563.6	36%	493.2	519.7	5%	2,543.1	2,714.8	7%
Customer Contributions	(14.3)	(30.1)	110%	(14.4)	(32.8)	127%	(14.9)	(28.7)	93%	(15.5)	(39.2)	153%	(16.0)	(79.1)	394%	(75.1)	(209.9)	180%
Net	**512.5**	**435.3**	**-15%**	**621.1**	**584.3**	**-6%**	**459.5**	**520.3**	**13%**	**397.7**	**524.4**	**32%**	**477.2**	**440.6**	**-8%**	**2,468.0**	**2,504.8**	**1%**

Rounding variances may exist

Notes:

In-Service Additions excludes Other Non Rate-Regulated Utility Assets

TAB 12

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

UNDERTAKING NO. JTC3.27:

Reference(s): **1B-SEC-8**

To provide the basis for the distribution system plan investments in 2017 and 2018 and 2019.

RESPONSE:

In reviewing the transcript from the Technical Conference, Toronto Hydro interprets this undertaking as a request to provide an explanation of the capital related metrics on the utility's annual corporate scorecards, filed in the response to interrogatory 1B-SEC-8. There are three different capital related metrics on the corporate scorecards: THESL Regulated Capital (2016 and 2017); 1-Year Distribution System Plan Investment (2018); and 5-Year CIR Distribution System Plan Investment (2018 and 2019). Each of these metrics are explained below.

Table 1: Scorecard Measures Descriptions

Year	Scorecard Measure	Description
2015	THESL Regulated Capital	This metric tracked the capital expenditure plan for the 2015 fiscal year, gross of capital contributions received from customers, and excluding major projects (e.g. Operational Centers Consolidation Program), capital contributions to HONI, capital expenditures tracked in deferral and variance accounts (e.g. Externally Driven Capital), and certain grid modernization projects (e.g. Local Demand Response).

Year	Scorecard Measure	Description
2016 & 2017	THESL Regulated Capital	This metric tracked the capital expenditure plan for the 2016 and 2017 fiscal year, net of capital contributions received from customers, and excluding major projects (e.g. Copeland), capital contributions to HONI, capital expenditures tracked in deferral and variance accounts (e.g. Externally Driven Capital), and certain grid modernization projects (e.g. Local Demand Response).
2018	1 Year Distribution System Plan Investment	This metric tracked the execution of the 2018 capital expenditure plan that flowed from the capital-related revenue requirement approved by the OEB in Toronto Hydro's last rebasing application. It did not include capital expenditures reflected in deferral and variance accounts (e.g. Externally Driven Capital).
2018 & 2019	5 Year Distribution System Plan Investment	This metric tracked the execution of the 2015-2019 capital expenditure plan that flowed from the capital related revenue requirement approved by the OEB in Toronto Hydro's last rebasing application. It did not include capital expenditures reflected deferral and variance accounts (e.g. Externally Driven Capital).

TAB 13

3.3. Allowance for Funds Used During Construction (AFUDC)

The Accounting Procedures Handbook, Article 410, allows the utility to capitalize an allowance for funds used during construction ("AFUDC"). The AFUDC rate applied by Toronto Hydro for 2010 to 2013 actuals and 2014 forecast is based on the OEB-prescribed rate. The forecasted 2015 capital expenditures are based on MIFRS and thus include AFUDC calculated based on Toronto Hydro's weighted average cost of debt.

3.4. Inflation

From 2016 onwards to 2019, inflation costs at 2.07% per year, consistent with the Statistic Canada Consumer Price Index ("CPI") for Toronto[3], are also included within this category.

3.5. Miscellaneous

Miscellaneous capital expenditures primarily include pre-capitalized inventory and major tools. Capital expenditures related to pre-capitalized inventory is dependent on the change in capital inventory levels year over year. Toronto Hydro invests in major tools and testing equipment to allow employees to continue to complete work effectively and efficiently. The utility invests in major tools on an ongoing basis to replace worn or broken tools, and as required to install, commission and maintain new technologies. These are regular utility expenses that are essential to being able to perform necessary capital and maintenance work.

[3] Statistics Canada, *Consumer Price Index, by city (Index)*, (Ottawa: Statistics Canada, 2014), online: Statistics Canada <http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ45a-eng.htm>.

To maximize the usefulness of these appendices, Toronto Hydro mapped its historical and future capital expenditures to the investment categories and programs presented in the DSP, at Exhibit 2B. Variance explanations related to Toronto Hydro's capital expenditures are provided in Exhibit 2B, Section E4.

Toronto Hydro confirms that no non-distribution activities are included in the plan presented in this application.

2. ACCOUNTING TREATMENT FOR CWIP

Some of Toronto Hydro's capital projects may be in progress at the reporting cut-off date. In such cases, capital costs are recorded in a CWIP account until the project work is completed. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that necessarily take a substantial period of time (exceeding six months) to get ready for their intended use. Further information follows.

3. COMPONENTS OF CAPITAL EXPENDITURES

Toronto Hydro's capital expenditures under the Other Capital Expenditures category (in Appendix 2-AB) includes AFUDC and miscellaneous capital, which are described below.

3.1 Allowance for Funds Used During Construction (AFUDC)

The OEB's Accounting Procedures Handbook, Article 410, directs utilities to capitalize AFUDC. The AFUDC rate applied by Toronto Hydro under MIFRS for 2015 to 2017 actuals, 2018 to 2019 bridge, and 2020 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 55:

Reference(s): **Exhibit 2A, Tab 4, Schedule 1, p. 2**
Chapter 2 Appendices, Appendix 2-AA

Preamble:

Toronto Hydro notes that the AFUDC rate applied under MIFRS is based on the weighted average cost of borrowing.

a) Please confirm that Toronto Hydro uses its "actual" weighted average cost of borrowing for the historical period and its applied-for weighted average cost of borrowing for the forecast period (Exhibit 2A / Tab 4 / Schedule 1 / p. 2).

b) Please provide the AFUDC percentages (%) for each year (2015-2024) and the total capital to which the AFUDC is applied. Please reconcile to the total annual AFUDC amounts shown in Appendix 2-AA.

RESPONSE:

a) Confirmed.

b) Please see Table 1 below. Note that the amounts presented are an average of monthly amounts for each year. Toronto Hydro confirms that the total annual AFUDC ties back to the amounts shown in Appendix 2-AA.

1 **Table 1: 2015-2024 AFUDC**

Program ($M)	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
AFUDC	10.8	12.5	9.8	6.0	4.0	6.0	8.2	8.7	8.9	7.7
Average monthly CWIP	288.9	284.8	254.0	166.6	110.3	142.4	195.2	205.0	210.4	182.4
AFUDC Percentage	3.7%	4.4%	3.9%	3.6%	3.6%	4.2%	4.2%	4.2%	4.2%	4.2%

OEB Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2020 Test Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$2,584,564,841	3.71%	$95,887,356
2	Short-term Debt	4.00%	(1)	$184,611,774	2.61%	$4,818,367
3	**Total Debt**	60.0%		$2,769,176,616	3.64%	$100,705,723
	Equity					
4	Common Equity	40.00%		$1,846,117,744	8.82%	$162,827,585
5	Preferred Shares	0.00%		$ -		$ -
6	**Total Equity**	40.0%		$1,846,117,744	8.82%	$162,827,585
7	**Total**	100.0%		$4,615,294,360	5.71%	$263,533,308

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO OEB STAFF

UNDERTAKING NO. JTC4.4:

Reference(s): **2A-Staff-55(b)**

With reference to 2A-Staff-55, part b, to advise why you wouldn't use the regulated entity's weighted average cost of borrowing in the calculation.

RESPONSE:

Toronto Hydro believes that using actual interest rates that arise from debt that has been publicly issued by its parent company, Toronto Hydro Corporation (THC), reflects the most accurate cost of borrowing.

Toronto Hydro's treatment of the cost of borrowing is consistent with the OEB's guidance in the Accounting Procedures Handbook (APH), Article 410:[1]

> Where incurred debt is acquired on an arm's length basis, the actual borrowing costs should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS.

[1] Ontario Energy Board, Accounting Procedures Handbook for Electricity Distributors, Article 410, Accounting for Specific Items Property, Plant and Equipment and Intangible (issued December 2011) at page 27.

Article 410 also states that for the purposes of applying the borrowing costs,[2]

> … where a distributor utility is held by a non-regulated parent, and that parent issued debt acquired on an arm's length basis which is flowed through to the regulated subsidiary at the market interest rates, the utility can apply the actual debt cost.

[2] Ibid.

TAB 14

how the utility has identified specific outcomes valued by its customers and how its plans and proposed expenditures deliver those outcomes.

1.1 Toronto Hydro's 2020-2024 Custom Performance Measures

To remain responsive to customer needs and preferences and demonstrate continuous improvement in performance setting and tracking, Toronto Hydro has proposed 15 custom measures within its Outcomes Framework that are incremental to measures tracked and assessed by the OEB, for a total of 44 unique measures to be reported annually.[12] See Appendix A for a full list of measures to be reported annually to the OEB. For a comprehensive discussion of Toronto Hydro's custom measures for the 2020-2024 plan period, please refer to Exhibit 2B, Section C2. Toronto Hydro's proposed custom measures reflect a thorough understanding of customer priorities and provide assurance that value for money will be achieved through the utility's 2020-2024 Distribution System Plan.

Table 1: 2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	Customer Satisfaction	Customers on eBills	Improve
Safety	Safety	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	System Reliability	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve

[12] These proposed measures will monitor distribution system planning process performance.

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Financial	**Cost Control**	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per km	Monitor
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion Rate	Monitor

Toronto Hydro's custom performance measures, and the targets related to all measures in general (including the Electricity Distributor Scorecard and the Electricity Service Quality Requirements), have been developed on the basis of the proposals, plans, and associated rates contained in this Application. To the extent that Toronto Hydro's approvals differ from those it seeks in this Application, then the utility would need to reforecast and re-assess its forecasted attainable performance for the period. Further, there are risks outside of Toronto Hydro's control which may also affect its ability to achieve performance targets.

2. PERFORMANCE MANAGEMENT

Toronto Hydro is an efficient organization that strives to promote its history of productivity and customer cost savings. Inherent in its focus on outputs and value is the emphasis on measuring and tracking performance, using internal and external benchmarking.

This section centralizes the utility's discussion of productivity and includes summaries of benchmarking studies relating to Toronto Hydro's performance relative to its peers. The activities captured within the following discussions are testament to the utility's commitment to ensure continuous improvement in the efficiency of key operational tasks that ultimately contribute to value-for-money for customers.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION

UNDERTAKING NO. JTC2.9:

Reference(s): **1B-EP-4 (a)**
2B-VECC-11

To clarify on the record what will be used for SAIDI, SAIFI and the other metrics in the scorecard. (Supplemental): to advise whether THESL will use numeric targets for the two categories of performance metrics, that are improve or maintain quarterly

RESPONSE:

Table 1 provides a consolidated summary of Toronto Hydro's proposed custom performance measures, associated baselines, and targets. Further details for these measures are provided in Exhibit 2B, Section C. The utility's performance objectives for the OEB's Electricity Distributor Scorecard measures are discussed in Exhibit 1B, Tab 2, Schedule 2. It is not Toronto Hydro's proposal to establish specific numeric targets. The utility is proposing directional targets relative to specific numeric baselines. As summarized in the table below, for the majority of its "improve" targets, the utility has provided estimated forecasts of performance for the 2020-2024 period. Toronto Hydro's ability to deliver on these outcomes is contingent on the OEB's approval of the rates proposed to fund the capital and operational plans detailed throughout the application. Therefore, Toronto Hydro will not be in a position to make any final commitment with respect to its targets until it after it has received the OEB's Decision in this application, and conducted a business planning cycle having regard for that Decision.

Table 1: Summary of Custom Performance Measures & Targets

Measure	Baseline	2020-2024 Target for Proposed Plan
Customers on eBills	224,420 customers *(2017 year-end)*	• Improve relative to baseline • Forecast performance is discussed in Exhibit 4A, Tab 2, Schedule 14, Table 2
Total Recordable Injury Frequency	1.3 recordable injuries per 100 workers *(2013-2017 average)*	• Maintain relative to baseline
Box Construction Conversion	3,151 box construction poles on the system *(2017 year-end)*	• Improve relative to baseline • Forecast performance is discussed in Exhibit 2B, Section E2, pages 26-27
Network Units Modernization	56% of network units on the system have submersible protectors *(2017 year-end)*	• Improve relative to baseline • Forecast performance is discussed in Exhibit 2B, Section C2.2.3
SAIDI - Defective Equipment	0.45 hours of interruption *(2013-2017 average)*	• Maintain relative to baseline • Forecast performance is discussed in Exhibit 2B, Section E2.2.2.3
SAIFI - Defective Equipment	0.52 interruptions *(2013-2017 average)*	• Maintain relative to baseline • Forecast performance is discussed in Exhibit 2B, Section E2.2.2.3
FESI-7 System	26 feeders *(2013-2017 average)*	• Improve relative to baseline
FESI-6 Large Customers	18 feeders *(2013-2017 average)*	• Maintain relative to baseline
System Capacity	14 stations with capacity constraints *(2013-2017 average)*	• Maintain relative to baseline
System Health (Asset Condition) - Poles	N/A (% of poles in HI4 and HI5 condition)	• Monitor performance
Direct Buried Cable Replacement	809 km of direct-buried cable on the system *(2017 year-end)*	• Improve relative to baseline • Forecast performance is discussed in Exhibit 2B, Section E2, pages 27-28
Average Wood Pole Replacement Cost	N/A	• Monitor performance

Measure	Baseline	2020-2024 Target for Proposed Plan
Vegetation Management Cost per Km	N/A	• Monitor performance
Oil Spills Containing PCBs	9 spills *(2013-2017 average)*	• Improve relative to baseline • As noted in Exhibit 2B, Section E2, Table 1, Toronto Hydro's objective is to endeavour to eliminate the risk of PCB-contaminated oil spills by 2025. The utility's PCB risk reduction plan is summarized for each system type (e.g. Overhead) in Exhibit 2B, Section D2.2.
Waste Diversion Rate	N/A (% waste diverted from landfills)	• Monitor performance

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO POWER WORKERS UNION

UNDERTAKING NO. JTC2.11:

Reference(s): 2B-PWU-3(a)

With reference to 2B-PWU-3(a), to provide the period of time for which baseline data is lacking; to advise the years the UMS data pertains to; to provide evidentiary references.

RESPONSE:

As noted in 2B-PWU-3(a), Toronto Hydro seeks to establish the baselines and targets for its performance measures on the basis of at least five years of historical data. With respect to the Average Wood Pole Replacement Cost measure, Toronto Hydro is proposing to report each year of data based on a three-year average, which aligns with the methodology used in the UMS Unit Cost Benchmarking Study. For greater clarity, the three-year average from 2014 to 2016 would represent one out of the five years of baseline data that the utility requires. Currently, data is only available for three reporting years as summarized in the table below.

Table 1: Current Availability of Data

Year	Dataset Required (Available)
1	2014-2016 Average (Available)
2	2015-2017 Average (Available)
3	2016-2018 Average (Available)
4	2017-2019 Average (Not Available)
5	2018-2020 Average (Not Available)

As explained in Exhibit 1B, Tab 2, Schedule 1, Appendix B, the UMS Unit Cost Benchmarking Study used unit costs for the years 2014 through 2016. The unit cost data provided by Toronto Hydro to UMS can be found in the utility's response to interrogatory 1B-Staff-9, Appendix L.

TAB 15

Utility	2015 Gross	2015 CC	2015 Net	2015 Depr	2016 Gross	2016 CC	2016 Net	2016 Depr	2017 Gross	2017 CC	2017 Net	2017 Depr	2018 Gross	2018 CC	2018 Net	2018 Depr
Alectra Utilities Corporation	$ 364,268,455	$ 47,506,346	$ 316,762,109	$ 113,106,491	$ 281,306,153	$ 48,905,031	$ 232,401,122	$ 122,083,435	$ 319,754,362	$ 65,651,383	$ 254,102,979	$ 113,975,594	$ 294,858,527	$ 62,381,505	$ 232,477,022	$ 129,483,639
Algoma Power Inc.	$ 10,888,963	$ 157,118	$ 10,731,845	$ 3,136,802	$ 8,580,000	$ -	$ 8,580,000	$ 3,326,205	$ 7,472,000	$ 137,000	$ 7,335,000	$ 3,438,399	$ 9,510,000	$ 69,000	$ 9,441,000	$ 3,600,160
Atikokan Hydro Inc.	$ 268,667	$ 19,966	$ 248,701	$ 180,844	$ 359,099	$ 19,209	$ 339,890	$ 189,853	$ 260,787	$ -	$ 260,787	$ 192,622	$ 716,351	$ -	$ 716,351	$ 205,391
Bluewater Power Distribution Corporation	$ 7,641,889	$ 360,407	$ 7,281,482	$ 4,554,631	$ 7,898,911	$ 272,609	$ 7,626,302	$ 4,135,676	$ 7,707,327	$ -	$ 7,707,327	$ 4,042,541	$ 9,241,677	$ -	$ 9,241,677	$ 3,834,546
Brantford Power Inc.	$ 4,502,042	$ 308,810	$ 4,193,232	$ 3,004,084	$ 4,630,910	$ 494,077	$ 4,136,833	$ 3,153,797	$ 4,357,574	$ 524,289	$ 3,833,285	$ 3,168,628	$ 4,322,647	$ 813,883	$ 3,508,764	$ 3,116,154
Burlington Hydro Inc.	$ 10,253,246	$ 1,950,451	$ 8,302,795	$ 4,973,073	$ 11,716,382	$ 4,410,445	$ 7,305,937	$ 5,255,671	$ 13,264,151	$ 4,681,623	$ 8,582,529	$ 5,562,540	$ 13,483,193	$ 3,151,665	$ 10,331,528	$ 5,927,266
Canadian Niagara Power Inc.	$ 9,293,758	$ 1,264,311	$ 8,029,447	$ 4,175,124	$ 10,470,000	$ 1,370,000	$ 9,100,000	$ 4,271,027	$ 10,493,000	$ 1,327,000	$ 9,166,000	$ 4,506,021	$ 17,371,000	$ 1,812,000	$ 15,559,000	$ 4,443,841
Centre Wellington Hydro Ltd.	$ 1,884,001	$ 13,625	$ 1,870,376	$ 543,004	$ 2,181,292	$ 48,495	$ 2,132,797	$ 548,179	$ 1,501,988	$ 284,435	$ 1,217,553	$ 562,972	$ 1,453,404	$ 258,315	$ 1,195,089	$ 574,190
Chapleau Public Utilities Corporation	$ 101,175	$ -	$ 101,175	$ 50,827	$ 36,284	$ -	$ 36,284	$ 52,874	$ 56,756	$ -	$ 56,756	$ 49,114	$ 512,765	$ -	$ 512,765	$ 107,640
EPCOR Electricity Distribution Ontario Inc. (Collus Powerstream)	$ 2,443,137	$ 745,573	$ 1,697,564	$ 742,598	$ 3,765,684	$ 1,739,589	$ 2,026,095	$ 845,096	$ 3,469,137	$ 527,957	$ 2,941,180	$ 944,462	$ 2,952,067	$ 904,892	$ 2,047,176	$ 1,008,075
Cooperative Hydro Embrun Inc.	$ 369,452	$ 82,004	$ 287,448	$ 118,183	$ 465,096	$ 6,450	$ 458,646	$ 124,120	$ 1,750,905	$ 75,885	$ 1,675,020	$ 145,310	$ 227,281	$ 60,245	$ 167,036	$ 163,632
E.L.K. Energy Inc.	$ 1,080,986	$ 267,274	$ 813,713	$ 364,814	$ 560,406	$ 438,399	$ 122,007	$ 343,271	$ 815,789	$ 242,709	$ 573,080	$ 347,372	$ 1,105,038	$ 172,754	$ 932,284	$ 366,333
Energy Plus Inc. (Brant + Cambridge)	$ 15,859,310	$ 4,496,481	$ 11,362,829	$ 6,042,661	$ 16,043,120	$ 2,763,059	$ 13,280,062	$ 6,114,161	$ 18,873,629	$ 3,212,372	$ 15,661,257	$ 5,912,459	$ 14,222,941	$ 5,262,706	$ 8,960,235	$ 5,745,054
Entegrus Powerlines Inc.	$ 9,347,691	$ 290,288	$ 9,057,403	$ 3,789,326	$ 9,393,902	$ 846,286	$ 8,547,616	$ 3,846,009	$ 10,212,278	$ 549,095	$ 9,663,183	$ 3,964,230	$ 12,166,321	$ 1,454,213	$ 10,712,108	$ 5,644,237
ENWIN Utilities Ltd.	$ 22,631,448	$ 5,036,747	$ 17,594,701	$ 9,831,922	$ 18,697,650	$ 1,069,571	$ 17,628,079	$ 10,501,504	$ 16,024,514	$ 2,315,399	$ 13,709,115	$ 11,469,873	$ 20,041,827	$ 2,325,435	$ 17,716,392	$ 11,878,593
ERTH Power Corporation (Erie Thames)	$ 5,928,082	$ 667,719	$ 5,260,364	$ 1,525,419	$ 4,385,303	$ 587,128	$ 3,798,175	$ 1,712,622	$ 3,874,526	$ 892,192	$ 2,982,334	$ 1,931,170	$ 4,455,228	$ 1,152,910	$ 3,302,317	$ 1,958,311
Espanola Regional Hydro Distribution Corporation	$ 244,019	$ -	$ 244,019	$ 96,039	$ 426,403	$ -	$ 426,403	$ 129,660	$ 641,889	$ -	$ 641,889	$ 144,902	$ 479,403	$ -	$ 479,403	$ 151,428
Essex Powerlines Corporation	$ 6,672,825	$ 1,448,183	$ 5,224,642	$ 2,537,950	$ 4,879,788	$ 931,021	$ 3,948,767	$ 1,493,988	$ 6,373,189	$ 921,652	$ 5,451,536	$ 2,173,960	$ 6,383,352	$ 1,167,137	$ 5,216,215	$ 2,038,972
Festival Hydro Inc.	$ 3,156,899	$ 170,827	$ 2,986,072	$ 2,428,856	$ 2,438,323	$ 206,585	$ 2,231,738	$ 2,156,996	$ 2,908,329	$ 369,219	$ 2,539,110	$ 2,264,309	$ 3,761,249	$ 585,407	$ 3,175,842	$ 2,388,518
Fort Frances Power Corporation	$ 200,667	$ -	$ 200,667	$ 217,683	$ 392,772	$ -	$ 392,772	$ 210,483	$ 641,863	$ -	$ 641,863	$ 318,110	$ 511,691	$ -	$ 511,691	$ 329,410
Greater Sudbury Hydro Inc.	$ 8,891,797	$ 1,327,041	$ 7,564,756	$ 3,844,521	$ 8,626,092	$ 915,758	$ 7,710,334	$ 3,685,266	$ 9,491,829	$ 707,218	$ 8,784,611	$ 3,666,463	$ 10,886,000	$ 1,214,036	$ 9,671,964	$ 3,843,665
Grimsby Power Incorporated	$ 10,291,335	$ 1,228,744	$ 9,062,590	$ 794,526	$ 1,398,920	$ 304,022	$ 1,094,898	$ 1,081,719	$ 2,147,523	$ 723,784	$ 1,423,739	$ 1,108,916	$ 1,866,440	$ 363,406	$ 1,503,034	$ 1,120,220
Guelph Hydro Electric Systems Inc.	$ 13,947,373	$ 5,139,636	$ 8,807,737	$ 4,892,433	$ 17,025,784	$ 3,065,993	$ 13,959,791	$ 5,645,805	$ 14,785,381	$ 1,305,661	$ 13,479,720	$ 5,963,945	$ 12,397,374	$ 4,936,780	$ 7,460,594	$ 6,212,742
Halton Hills Hydro Inc.	$ 8,295,868	$ 2,271,997	$ 6,023,871	$ 1,780,440	$ 8,312,782	$ 654,903	$ 7,657,879	$ 1,795,856	$ 9,883,110	$ 1,482,936	$ 8,400,174	$ 1,950,940	$ 8,507,661	$ 979,445	$ 7,528,216	$ 2,053,294
Hearst Power Distribution Company Limited	$ 188,878	$ 2,609	$ 186,269	$ 344,309	$ 147,424	$ 29,251	$ 118,173	$ 94,346	$ 166,897	$ 13,751	$ 153,146	$ 100,725	$ 278,156	$ 29,510	$ 248,646	$ 124,014
Hydro 2000 Inc.	$ 36,025	$ -	$ 36,025	$ 51,899	$ 26,335	$ -	$ 26,335	$ 52,237	$ 45,376	$ -	$ 45,376	$ 47,324	$ 44,997	$ 3,750	$ 41,247	$ 45,712
Hydro Hawkesbury Inc.	$ 612,706	$ 93,493	$ 519,213	$ 188,834	$ 1,513,998	$ 17,741	$ 1,496,257	$ 194,087	$ 983,217	$ 49,138	$ 934,078	$ 225,270	$ 218,486	$ 59,897	$ 158,590	$ 263,204
Hydro One Networks Inc.	$ 828,346,491	$ 85,771,343	$ 742,575,148	$ 364,748,322	$ 721,111,668	$ 55,740,572	$ 664,975,416	$ 375,051,162	$ 744,465,071	$ 55,055,191	$ 689,409,880	$ 388,008,854	$ 691,819,864	$ 51,882,608	$ 639,937,256	$ 397,485,263
Hydro Ottawa Limited	$ 147,267,262	$ 24,928,647	$ 122,338,615	$ 37,990,760	$ 103,176,348	$ 21,578,316	$ 81,598,032	$ 40,097,278	$ 122,692,101	$ 24,998,607	$ 97,693,494	$ 41,682,623	$ 122,854,180	$ 22,598,352	$ 100,255,828	$ 45,984,835
Innpower Corporation	$ 19,803,244	$ 2,188,564	$ 17,614,680	$ 1,879,151	$ 6,882,669	$ 2,265,141	$ 4,617,528	$ 2,348,783	$ 4,460,324	$ 966,418	$ 3,493,906	$ 2,363,240	$ 5,426,267	$ 1,358,814	$ 4,067,453	$ 2,503,452
Synergy North Corporation – Kenora Rate District	$ 643,008	$ 83,037	$ 559,971	$ 569,016	$ 640,560	$ 38,966	$ 601,594	$ 678,946	$ 589,140	$ 43,418	$ 545,722	$ 637,871	$ 629,080	$ -	$ 629,080	$ 653,653
Kingston Hydro Corporation	$ 3,206,337	$ 96,296	$ 3,110,041	$ 1,690,705	$ 5,834,543	$ 592,672	$ 5,241,871	$ (1,600,252)	$ 8,172,029	$ 4,666,656	$ 3,505,373	$ 2,095,293	$ 5,289,056	$ 1,400,024	$ 3,889,032	$ 2,193,987
Kitchener-Wilmot Hydro Inc.	$ 21,918,728	$ 9,593,246	$ 12,325,482	$ 2,349,311	$ 24,286,420	$ 8,950,517	$ 15,335,903	$ 8,710,983	$ 22,408,879	$ 6,242,858	$ 16,166,021	$ 8,565,130	$ 21,257,307	$ 4,696,647	$ 16,560,661	$ 9,116,473
Lakefront Utilities Inc.	$ 1,829,242	$ 58,465	$ 1,770,776	$ 1,121,030	$ 3,079,543	$ 80,316	$ 2,999,226	$ 1,178,282	$ 2,562,505	$ 202,427	$ 2,360,078	$ 1,184,544	$ 1,548,781	$ 358,852	$ 1,189,929	$ 1,091,129
Lakeland Power Distribution Ltd.	$ 3,088,920	$ 194,049	$ 2,894,871	$ 1,200,180	$ 2,502,246	$ 551,703	$ 1,950,543	$ 1,349,997	$ 2,345,613	$ 365,698	$ 1,979,915	$ 1,414,343	$ 2,440,139	$ 347,817	$ 2,092,322	$ 1,453,186
London Hydro Inc.	$ 33,025,844	$ 3,788,551	$ 29,237,293	$ 16,858,883	$ 35,609,719	$ 3,313,477	$ 32,296,242	$ 17,771,936	$ 32,522,017	$ 5,205,870	$ 27,316,147	$ 17,350,372	$ 48,041,965	$ 4,795,268	$ 43,246,697	$ 17,881,259
Midland Power Utility Corporation (now Newmarket Tay)	$ 629,276	$ 36,084	$ 593,193	$ 644,006	$ 763,589	$ 60,073	$ 703,516	$ 816,330	$ 1,376,632	$ 110,794	$ 1,265,838	$ 796,446	$ -	$ -	$ -	$ -
Milton Hydro Distribution Inc.	$ 15,617,439	$ 1,823,780	$ 13,793,659	$ 2,761,704	$ 11,320,875	$ 3,333,020	$ 7,987,855	$ 3,301,468	$ 8,924,115	$ 2,879,515	$ 6,044,600	$ 3,482,059	$ 11,224,369	$ 2,920,318	$ 8,304,051	$ 3,761,991
Newmarket-Tay Power Distribution Ltd.	$ 14,686,360	$ 1,826,732	$ 12,859,628	$ 2,904,007	$ 9,949,992	$ 6,438,453	$ 3,511,539	$ 3,068,914	$ 6,191,846	$ 1,405,507	$ 4,786,339	$ 3,598,756	$ 3,257,127	$ 869,125	$ 2,388,002	$ 5,747,249
Niagara Peninsula Energy Inc.	$ 14,979,925	$ 5,600,233	$ 9,379,692	$ 6,099,694	$ 15,426,432	$ 4,031,451	$ 11,394,981	$ 6,462,385	$ 14,933,017	$ 2,180,761	$ 12,752,256	$ 6,937,287	$ 14,985,908	$ 2,240,998	$ 12,744,910	$ 7,449,739
Niagara-on-the-Lake Hydro Inc.	$ 1,713,213	$ 600,722	$ 1,112,491	$ 775,384	$ 2,828,580	$ 1,603,277	$ 1,225,303	$ 741,925	$ 1,622,011	$ 319,954	$ 1,302,058	$ 717,757	$ 3,282,575	$ 723,766	$ 2,558,809	$ 726,405
North Bay Hydro Distribution Limited	$ 6,896,610	$ 703,198	$ 6,193,413	$ 1,693,086	$ 5,570,545	$ 352,323	$ 5,218,222	$ 926,479	$ 6,191,840	$ 728,037	$ 5,463,803	$ 1,833,811	$ 6,940,048	$ 558,617	$ 6,381,431	$ 2,854,199
Northern Ontario Wires Inc.	$ 424,755	$ 123,412	$ 301,343	$ 368,228	$ 692,947	$ 23,550	$ 669,397	$ 380,214	$ 810,159	$ 8,321	$ 801,838	$ 414,285	$ 845,234	$ -	$ 845,234	$ 420,378
Oakville Hydro Electricity Distribution Inc.	$ 15,777,343	$ 5,082,947	$ 10,694,396	$ 8,545,048	$ 20,301,606	$ 9,686,384	$ 10,615,222	$ 8,984,647	$ 17,886,851	$ 5,040,755	$ 12,846,096	$ 9,156,545	$ 22,655,649	$ 5,599,139	$ 17,056,510	$ 9,123,190
Orangeville Hydro Limited	$ 1,293,107	$ 200,284	$ 1,092,823	$ 667,675	$ 1,940,991	$ 395,789	$ 1,545,202	$ 651,574	$ 2,551,610	$ 633,962	$ 1,917,648	$ 687,935	$ 1,778,360	$ 205,712	$ 1,572,648	$ 713,571
Orillia Power Distribution Corporation	$ 2,239,251	$ 134,720	$ 2,104,531	$ 1,121,075	$ 5,606,188	$ 396,371	$ 5,209,817	$ (246,829)	$ 3,572,280	$ 349,120	$ 3,223,160	$ 1,183,380	$ 2,262,041	$ 171,780	$ 2,090,261	$ 1,222,768
Oshawa PUC Networks Inc.	$ 15,178,835	$ 3,324,147	$ 11,854,688	$ 3,797,997	$ 10,425,039	$ 1,084,859	$ 9,340,180	$ 4,437,246	$ 9,083,922	$ 1,226,128	$ 7,857,794	$ 4,362,249	$ 16,868,642	$ 3,911,288	$ 12,957,354	$ 4,981,587
Ottawa River Power Corporation	$ 959,680	$ 179,612	$ 780,068	$ 765,290	$ 1,201,956	$ 96,899	$ 1,105,056	$ 1,503,773	$ 1,692,123	$ 263,533	$ 1,428,590	$ 717,910	$ 1,582,652	$ 136,450	$ 1,446,202	$ 900,205
Peterborough Distribution Incorporated	$ 7,704,000	$ 2,203,000	$ 5,501,000	$ 2,874,800	$ 5,766,000	$ 1,838,000	$ 3,928,000	$ 3,423,805	$ 5,847,000	$ 1,745,000	$ 4,102,000	$ 3,585,437	$ 5,124,000	$ 648,000	$ 4,476,000	$ 3,455,256
PUC Distribution Inc.	$ 6,710,692	$ 454,801	$ 6,255,891	$ 3,888,942	$ 5,988,626	$ 450,272	$ 5,538,354	$ 4,089,742	$ 6,352,193	$ 1,136,727	$ 5,215,467	$ 3,666,323	$ 5,575,711	$ 431,033	$ 5,144,679	$ 3,781,554
Renfrew Hydro Inc.	$ 510,990	$ 18,266	$ 492,724	$ 222,240	$ 437,215	$ 32,772	$ 404,442	$ 270,394	$ 558,903	$ 10,457	$ 548,446	$ 328,560	$ 984,506	$ 31,873	$ 952,632	$ 126,844
Rideau St. Lawrence Distribution Inc.	$ 598,917	$ 5,200	$ 593,717	$ 306,218	$ 480,494	$ 98,590	$ 381,904	$ 364,321	$ 1,201,654	$ 101,073	$ 1,100,581	$ 427,050	$ 558,128	$ 63,487	$ 494,642	$ 407,195
Sioux Lookout Hydro Inc.	$ 300,614	$ 40,513	$ 260,101	$ 210,722	$ 330,619	$ 29,696	$ 300,923	$ 217,627	$ 585,165	$ 115,657	$ 469,508	$ 223,701	$ 646,956	$ 80,920	$ 566,037	$ 244,833
St. Thomas Energy Inc. (now Entegrus)	$ 2,514,762	$ 355,700	$ 2,159,062	$ 1,148,681	$ 2,554,843	$ 608,283	$ 1,946,560	$ 1,254,621	$ 2,645,990	$ 813,088	$ 1,832,902	$ 1,311,590	$ -	$ -	$ -	$ -
Synergy North Corporation – Thunder Bay Rate District	$ 11,735,209	$ 1,984,671	$ 9,750,538	$ 3,228,843	$ 12,182,464	$ 2,737,839	$ 9,444,625	$ 3,385,685	$ 11,256,399	$ 973,179	$ 10,283,220	$ 3,544,405	$ 11,948,111	$ 1,243,211	$ 10,704,900	$ 3,600,977
Tillsonburg Hydro Inc.	$ 591,806	$ 336,487	$ 255,319	$ 325,196	$ 840,760	$ 81,140	$ 759,619	$ 327,997	$ 1,696,551	$ 458,663	$ 1,237,888	$ 364,128	$ 1,724,289	$ 95,802	$ 1,628,487	$ 419,420
Toronto Hydro-Electric System Limited	$ 465,402,574	$ 30,083,801	$ 435,318,773	$ 192,329,429	$ 617,138,762	$ 32,842,749	$ 584,296,013	$ 225,905,945	$ 548,964,114	$ 28,704,350	$ 520,259,764	$ 228,284,811	$ 563,606,573	$ 39,248,789	$ 524,357,783	$ 241,845,269
Veridian Connections Inc.	$ 27,411,798	$ 6,239,695	$ 21,172,103	$ 11,161,147	$ 31,520,006	$ 7,369,144	$ 24,150,862	$ 11,349,987	$ 26,811,166	$ 3,340,859	$ 23,470,307	$ 12,002,916	$ 29,421,418	$ 6,344,749	$ 23,076,670	$ 12,567,912
Wasaga Distribution Inc.	$ 1,040,957	$ 521,208	$ 519,749	$ 621,402	$ 1,473,765	$ 587,159	$ 886,606	$ 542,441	$ 1,737,291	$ 415,754	$ 1,321,537	$ 565,019	$ 1,422,849	$ 135,478	$ 1,287,371	$ 591,332
Waterloo North Hydro Inc.	$ 20,238,920	$ 7,373,641	$ 12,865,279	$ 8,510,773	$ 32,161,079	$ 12,636,204	$ 19,524,875	$ 8,271,633	$ 20,470,098	$ 4,578,501	$ 15,891,597	$ 8,643,425	$ 19,537,430	$ 2,968,930	$ 16,568,500	$ 8,973,807
Welland Hydro-Electric System Corp.	$ 2,506,400	$ 421,827	$ 2,084,573	$ 1,304,212	$ 3,128,400	$ 207,254	$ 2,921,146	$ 1,365,712	$ 2,332,938	$ 36,017	$ 2,296,921	$ 1,429,127	$ 2,186,056	$ 170,518	$ 2,015,538	$ 1,491,768
Wellington North Power Inc.	$ 817,661	$ -	$ 817,661	$ 346,404	$ 1,545,545	$ -	$ 1,545,545	$ 365,478	$ 744,253	$ -	$ 744,253	$ 407,729	$ 501,091	$ -	$ 501,091	$ 424,389
ERTH Power Corporation - West Coast Huron rate zone	$ 1,057,149	$ 46,777	$ 1,010,372	$ 257,196	$ 1,228,091	$ 122,777	$ 1,105,314	$ 279,897	$ 850,390	$ 241,529	$ 608,861	$ 340,018	$ 774,627	$ 89,552	$ 685,075	$ 382,620
Westario Power Inc.	$ 4,112,933	$ 148,625	$ 3,964,308	$ 1,653,966	$ 5,740,396	$ 584,438	$ 5,155,958	$ 1,638,686	$ 4,901,467	$ 497,727	$ 4,403,740	$ 1,886,263	$ 5,789,860	$ 415,354	$ 5,374,506	$ 1,926,937
Whitby Hydro Electric Corporation	$ 15,742,522	$ 10,178,882	$ 5,563,640	$ 3,588,586	$ 11,862,259	$ 2,961,787	$ 8,900,472	$ 2,742,165	$ 9,790,126	$ 1,795,019	$ 7,995,107	$ 3,659,835	$ 10,385,977	$ 2,470,429	$ 7,915,548	$ 4,756,936
SUM TOTAL	**$ 2,237,823,469**	**$ 281,600,814**	**$ 1,956,222,655**	**$ 863,846,600**	**$ 2,149,210,590**	**$ 252,897,853**	**$ 1,895,917,057**	**$ 925,455,322**	**$ 2,129,757,110**	**$ 243,851,828**	**$ 1,885,905,282**	**$ 946,039,197**	**$ 2,097,151,905**	**$ 248,372,590**	**$ 1,848,779,315**	**$ 997,889,808**

1.2 Depreciation and Amortization Expense

Toronto Hydro's depreciation and amortization expense from 2015 to 2020 is presented in Table 3 below. This summary is supported by Appendix A, which provides a breakdown of 2015-2020 depreciation expense by Uniform System of Accounts. An updated version of OEB Appendix 2-C is filed as Appendix B to this schedule.

Table 3: Depreciation and Amortization Expense[1] 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Depreciation and Amortization Expense	166.0	179.1	192.5	205.3	223.6	242.9

The 2018 actual and 2019 bridge depreciation and amortization expenses are $5.4 million and $4.6 million lower, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 1, page 6.

The differences in 2018 are primarily due to timing differences associated with the completion of the ERP and Copeland TS projects. The depreciation expense for 2019 is expected to be lower due to the reduced opening balance for fixed assets in 2019, and changes in the timing of in-service additions in the year resulting from the work that is being carried over from 2018 into 2019.

[1] Includes depreciation of the decommissioning costs and excludes derecognition. For inofmraiton about asset derecognition please see section 2.1 below and Exhibit 4B, Tab 1, Schedule 2.

2. DERECOGNITION

2.1 Derecognition Expense

Table 4 below summarizes Toronto Hydro's 2015 to 2020 derecognition expense. The 2018 actual and 2019 bridge expenses are $3.7 million and $2.3 million higher, respectively, than the forecasts included in Exhibit 4B, Tab 1, Schedule 2, page 1.

The differences in 2018 relate to overhead and underground distribution assets, as well as software assets. Toronto Hydro updated 2019 forecast based on a four year average of derecognition as opposed to a three year average in the original filing.

Table 4: Derecognition from 2015 to 2020 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge Updated	2020 Forecast
Derecognition	24.1	27.0	24.5	24.5	22.4	25.8