EB-2018-0165

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited ("Toronto Hydro") for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective January 1, 2020 to December 31, 2024.

.

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Panel 1 - Distribution Capital and Maintenance)

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Counsel for the School Energy Coalition

U-Staff-171 Appendix C

OEB Appendix 2-AB
Capital Expenditure Summary

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

Note: Variances due to rounding may exis

U-Staff-171 Appendix A

OEB Appendix 2-AB
Capital Expenditure Summary

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

OEB Appendix 2-AA
Capital Programs Table

Programs ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer and Generation Connections	31.7	40.1	21.9	44.0	39.8	42.9	43.9	44.8	45.6	46.3
Externally Initiated Plant Relocations & Expansion	2.2	2.6	2.6	5.0	11.9	11.4	20.8	4.6	4.7	4.5
Generation Protection, Monitoring and Control	-	2.1	0.0	0.6	10.9	3.7	2.3	2.4	2.5	2.7
Load Demand	9.9	16.8	16.2	16.4	23.5	11.3	11.4	18.5	22.6	23.6
Metering	14.5	17.4	24.8	22.0	26.1	22.6	14.8	23.6	30.6	39.2
System Access Total	**58.3**	**79.0**	**65.5**	**88.0**	**112.1**	**91.8**	**93.3**	**93.9**	**106.0**	**116.4**
Area Conversions	46.3	28.2	26.9	34.4	36.0	41.4	47.2	46.3	50.4	35.6
Network System Renewal	10.2	16.8	14.7	18.8	32.2	18.6	19.3	18.5	17.7	18.3
Reactive and Corrective Capital	42.0	54.3	55.5	66.1	63.7	61.2	62.4	63.5	64.4	65.8
Stations Renewal	11.3	11.6	19.0	21.9	22.0	27.5	35.3	29.4	27.0	22.4
Underground Renewal - Downtown	-	-	-	(0.0)	-	15.1	22.5	23.9	30.0	30.6
Underground Renewal - Horseshoe	115.5	80.7	83.1	69.1	55.8	93.0	88.7	90.3	93.1	95.2
Overhead Infrastructure Relocation	0.9	3.1	2.6	0.3	1.6	-	-	-	-	-
SCADAMATE R1 Renewal	3.5	4.9	2.1	1.1	1.9	-	-	-	-	-
PILC Piece Outs & Leakers	6.0	5.7	1.8	0.8	0.1	-	-	-	-	-
Underground Legacy Infrastructure	7.4	9.9	9.0	2.7	6.0	-	-	-	-	-
Overhead System Renewal	61.0	51.0	35.7	30.4	24.8	49.8	50.4	51.3	56.5	57.7
System Renewal Total	**304.1**	**266.1**	**250.3**	**245.5**	**244.2**	**306.6**	**325.7**	**323.1**	**339.0**	**325.5**
Energy Storage Systems	-	-	-	0.1	7.9	1.0	3.7	3.8	1.0	1.0
Network Condition Monitoring and Control	-	-	-	-	-	7.6	10.2	12.6	15.3	17.4
Overhead Momentary Reduction	0.0	-	-	-	0.3	-	-	-	-	-
Stations Expansion	23.0	34.5	59.4	21.0	29.1	19.5	40.0	49.3	12.5	15.2
System Enhancements	7.1	17.2	12.2	9.4	4.0	6.2	6.2	5.6	4.8	4.9
Handwell Upgrades	4.7	0.8	0.8	0.0	-	-	-	-	-	-
Polymer SMD-20 Renewal	3.0	0.3	0.0	0.4	-	-	-	-	-	-
Design Enhancement	0.0	0.6	(0.0)	0.0	0.2	-	-	-	-	-
System Service Total	**37.9**	**53.3**	**72.4**	**31.0**	**41.5**	**34.2**	**60.1**	**71.3**	**33.6**	**38.5**
Facilities Management and Security	15.4	9.0	6.3	1.7	3.5	11.6	11.8	12.1	12.3	12.6
Fleet and Equipment	4.1	3.7	4.7	2.9	3.6	8.6	8.9	8.5	8.7	7.8
IT/OT Systems	28.4	48.6	55.4	53.7	39.3	54.8	55.7	49.5	56.6	64.8
Control Operations Reinforcement	-	-	-	-	-	3.9	17.4	18.9	-	-
Operating Centers Consolidation Plan	31.6	48.3	32.2	-	-	-	-	-	-	-
Program Support	-	0.0	0.4	-	-	-	-	-	-	-
General Plant Total	**79.4**	**109.5**	**98.9**	**58.4**	**46.4**	**78.8**	**93.7**	**89.0**	**77.7**	**85.2**
AFUDC	10.8	12.5	9.8	8.9	4.0	6.0	8.2	8.7	8.9	7.7
Miscellaneous	0.8	(8.8)	0.9	3.8	(5.3)	1.0	0.8	1.2	0.6	1.0
Other Total	**11.6**	**3.7**	**10.7**	**12.7**	**(1.3)**	**7.0**	**9.0**	**9.8**	**9.5**	**8.7**
Subtotal	**491.4**	**511.6**	**497.8**	**435.6**	**443.0**	**518.4**	**581.8**	**587.1**	**565.7**	**574.4**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	(0.8)	(3.2)	(1.2)	(0.7)	(17.7)	(4.4)	(3.1)	(3.2)	(3.3)	(3.5)
Total	**490.6**	**508.4**	**496.6**	**434.9**	**425.3**	**514.0**	**578.8**	**583.9**	**562.4**	**570.9**

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.

In-Service Additions for the 2015-2019 Period

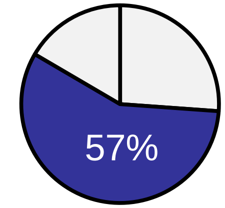
	Historical												Bridge			Historical/Bridge		
	2015			2016			2017			2018			2019			2015-2019		
In-Service Additions	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-10%)**	**Actual**	**Var.**	**CIR Filing (-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%**

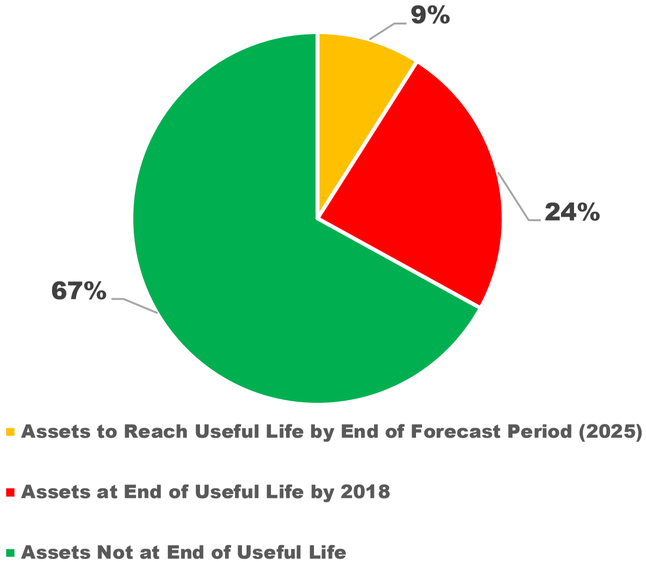
Rounding variances may exist

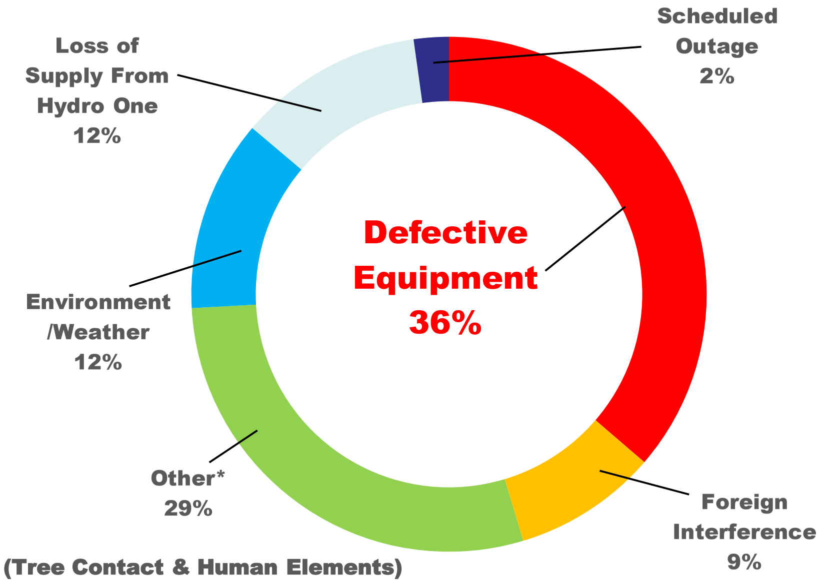
Notes:
In-Service Additions excludes Other Non Rate-Regulated Utility Assets

Renewing the System

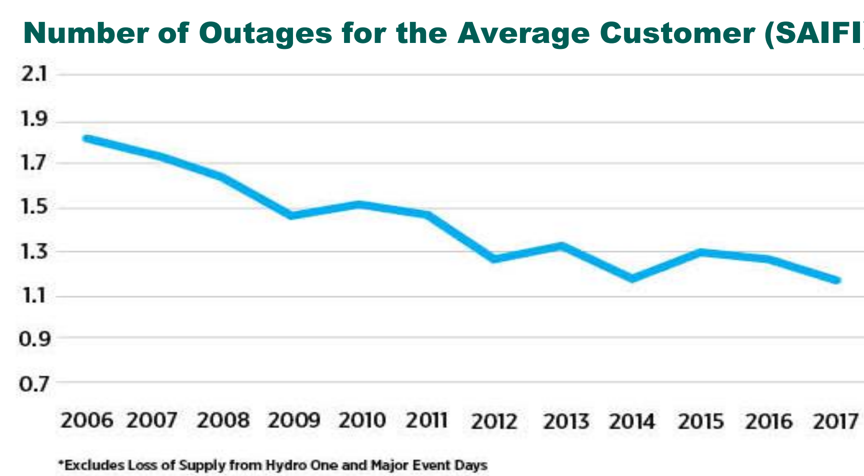
Our Operating Context







* (Tree Contact & Human Elements)



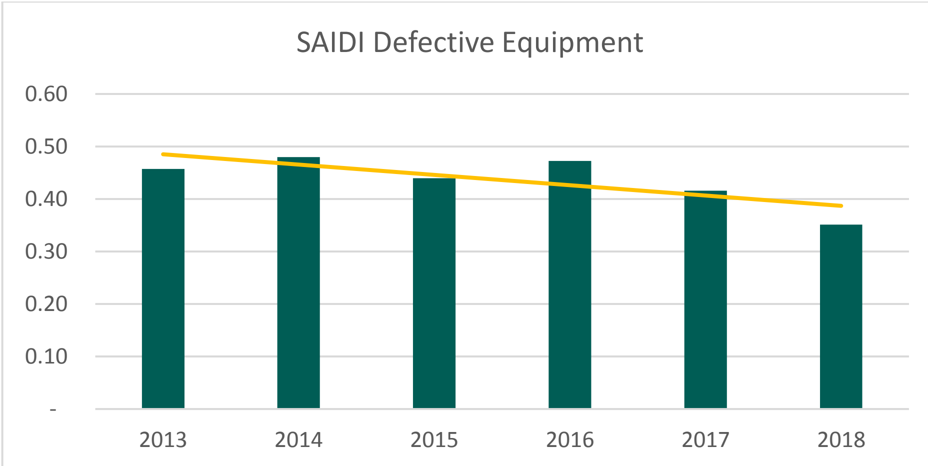


Figure 5: SAIDI (Defective Equipment) Performance 2013-2018

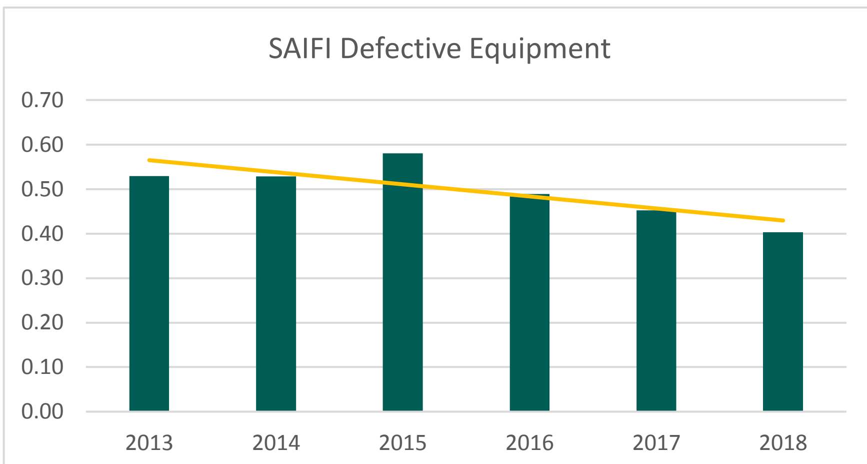


Figure 6: SAIFI (Defective Equipment) Performance 2013-2018

3.3.2 Feeders Experiencing Sustained Interruptions (FESI-7/6) - Worst Performing Feeders

FESI-7 System and FESI-6 Large Customer measures track the performance of feeders that experience the highest number of outages.[3] Between 2013 and 2018, FESI-7 System and

[3] These measures exclude interruptions caused by Major Event Days, Loss of Supply, scheduled outages, station bus-level interruptions and on the secondary side of the distribution transformer (e.g. on service wires or secondary bus).

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

INTERROGATORY 8:

Reference(s): **Exhibit 2A, Tab 10, Schedule 2, pages 1-2, Figures 1 and 2**

Preamble:

Scenarios 1 and 2 provide SAIFI and SAIDI in the filing manner required by OEB Appendix 2-G (Exhibit 2A, Tab 10, Schedule 3). Scenarios 3 and 4 provide SAIFI and SAIDI values by excluding additional externalities and controllable outages, to give a more normalized reflection of total system reliability. Each of these values provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

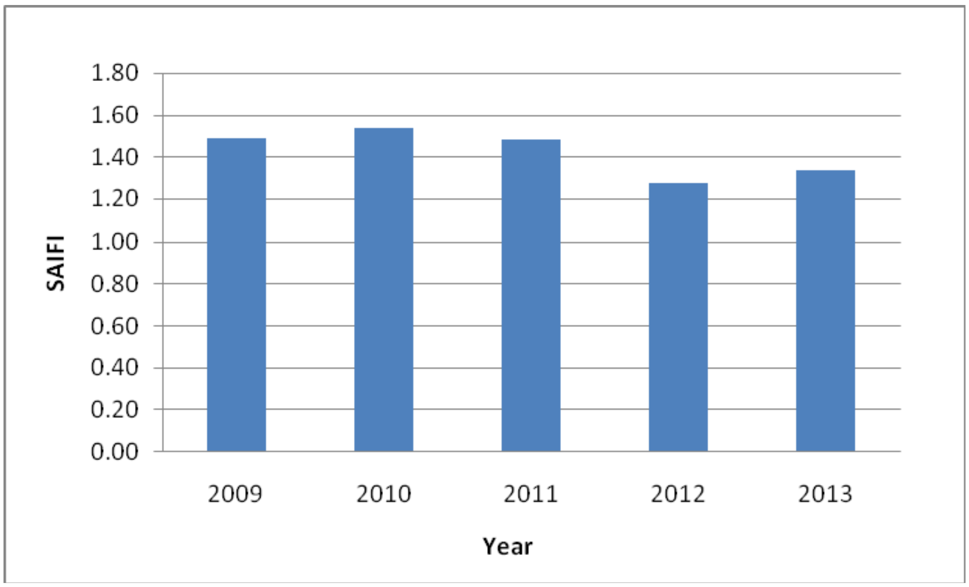
a) Confirm SAIDI and SAIFI are Metrics contained in the new OEB RRFE Scorecard for Electricity Distributors.
b) Please provide a historic SAIDI, SAIFI and CAIDI charts without LOS and MEDS, but including SOs
c) Provide a forecast of SAIDI, SAIFI and CAIDI for the period 2014-2019 including the CIR period 2016-2019, excluding LOS and MEDs, but including SOs.
d) Please provide the 5 year average SAIDI and SAIFI for the CIR Plan and Compare to Appendix 2-G historical Average

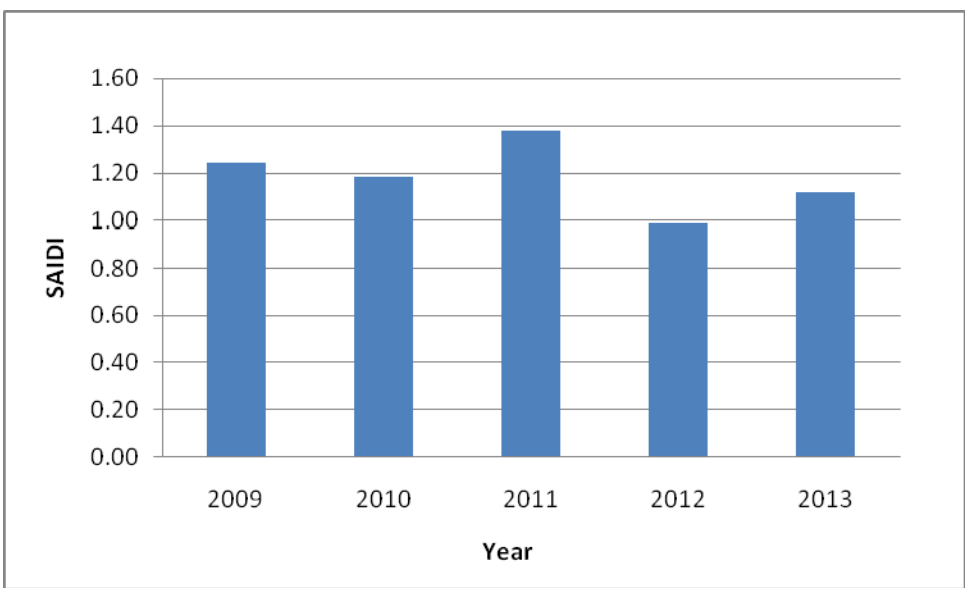
RESPONSE:

a) Confirmed.

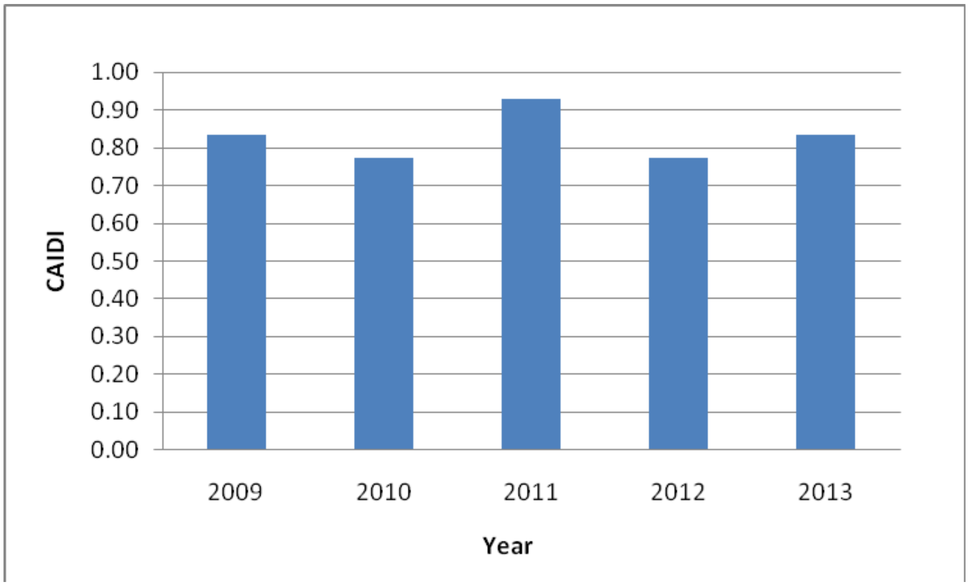
RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

b) Please see the following graphs for SAIFI, SAIDI and CAIDI without MEDs and Loss of Supply, but including Scheduled Outages.





RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES



c) The below table shows the 2014 Forecast and 2015 projections for SAIDI, SAIFI and CAIDI for the period 2014-2019 including the CIR period 2016-2019, excluding LOS and MEDs, but including Scheduled Outages. Please note that 2014 is a forecast, while 2015-2019 is a projection based on the completion of the capital investment and maintenance program detailed in this application.

	2014F	2015P	2016P	2017P	2018P	2019P
SAIFI	1.31	1.39	1.28	1.20	1.11	1.03
SAIDI	0.97	1.16	1.10	1.05	1.01	0.95
CAIDI	0.74	0.83	0.86	0.87	0.91	0.92

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES

d) The five-year SAIDI and SAIFI for the CIR Plan (above in part c) is calculated excluding MEDs and LOS. This is appropriate given that MEDs are by their nature unpredictable and LOS events are beyond Toronto Hydro's control. However, the historical averages presented in Appendix 2-G include MEDs (in accordance with the OEB's filing requirements) and are therefore not meaningfully comparable. As an alternative, the table below presents a comparison between the 2009-2013 actual and forecast and the 2015-2019 projected SAIFI and SAIDI, without MEDs and without Loss of Supply, but including Scheduled Outages.

	5-Year Average (2009-2013)	5-Year Average of CIR Plan (2015-2019)
SAIFI	1.42	1.20
SAIDI	1.18	1.05

5.11 Emergency Response

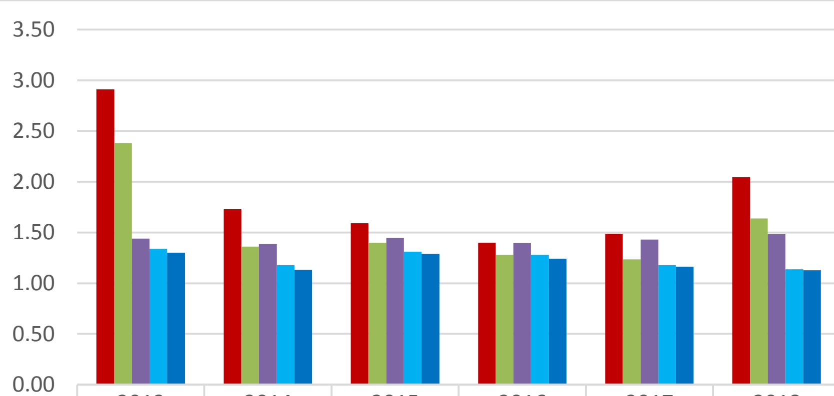
Toronto Hydro's Emergency Response performance decreased in 2018 when compared to the prior year. The 86.63 percent performance in 2018 compares to 93.6 percent in 2017. Over the course of 2018, Toronto Hydro experienced 11 significant weather events as compared to five in 2017. The total number of calls during a number of these events surpassed the number of field resources available for the company to respond within sixty minutes.

5.12 Reconnection Performance Standard

In 2018, Toronto Hydro's reconnection performance standard result was 99.65 percent, which is a slight increase from the 99.38 percent in 2017.

6. RELIABILITY PERFORMANCE

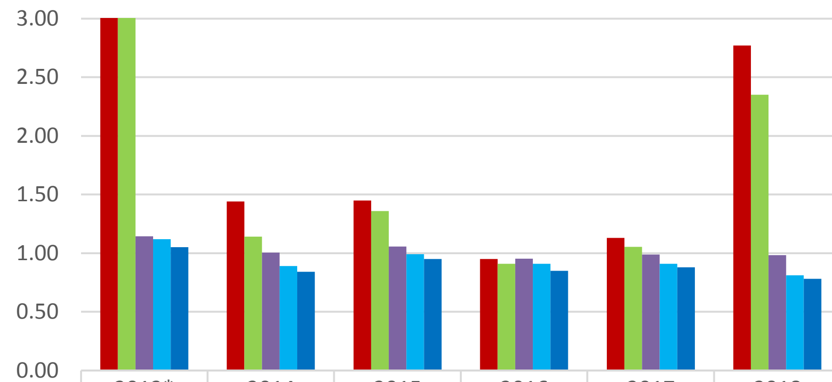
6.1 System Overview



	2013	2014	2015	2016	2017	2018
Total SAIFI	2.91	1.73	1.59	1.40	1.49	2.04
SAIFI Excluding LoS	2.38	1.36	1.40	1.28	1.24	1.64
SAIFI Excluding MED's	1.44	1.39	1.45	1.40	1.43	1.48
SAIFI Excluding MED's and LoS	1.34	1.18	1.31	1.28	1.18	1.14
SAIFI Excluding MED's, LoS and Scheduled Outages	1.30	1.13	1.29	1.24	1.16	1.13

Figure 16: System Level SAIFI

Toronto Hydro's 2018 System Level SAIFI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.



	2013*	2014	2015	2016	2017	2018
Total SAIDI	21.07	1.44	1.45	0.95	1.13	2.77
SAIDI Excluding LoS	17.70	1.14	1.36	0.91	1.05	2.35
SAIDI Excluding MED's	1.14	1.00	1.06	0.95	0.99	0.98
SAIDI Excluding MED's and LoS	1.12	0.89	0.99	0.91	0.91	0.81
SAIDI Excluding MED's, LoS and Scheduled Outages	1.05	0.84	0.95	0.85	0.88	0.78

* 2013 Values cut off above the chart due to the high SAIFI and SAIDI values prior to excluding MEDs.

Figure 17: System Level SAIDI

Toronto Hydro's 2018 System Level SAIDI performance decreased relative to 2017. This decrease in performance can be attributed to an increase in adverse weather events and loss of supply events.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 105:

Reference(s): Evidence Overview Presentation, p. 15

a) Please expand the SAIFI chart to include (a) 2018 data, and b) forecast 2019 to 2022 SAIFI levels.

b) Please provide a similar chart as requested in part (a) for SAIDI.

c) Please provide a table showing numerical values for the charts requested in parts (a) and (b).

RESPONSE:

a) Please see the chart below with a projection for 2019-2024.

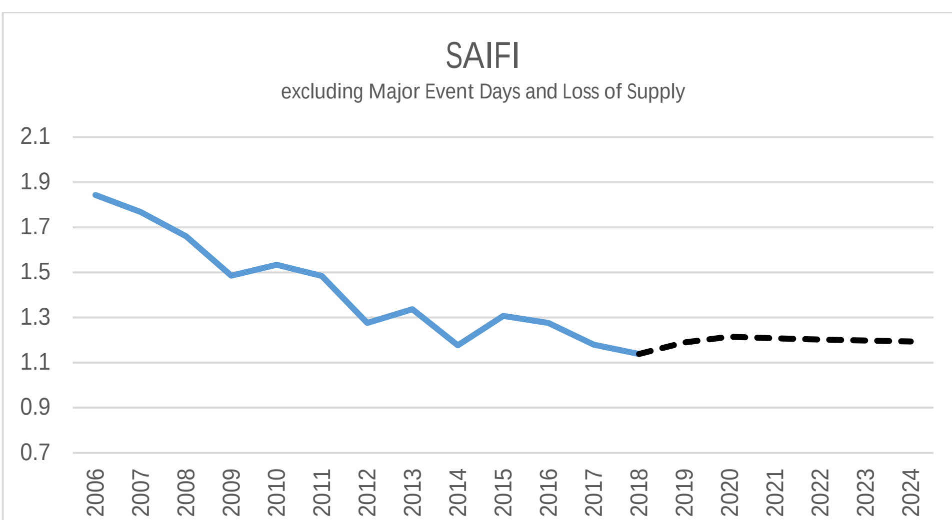


Figure 1: SAIFI Projections for 2019-2024 (excluding MED and LoS)

b) Please see the chart below with a projection for 2019-2024.

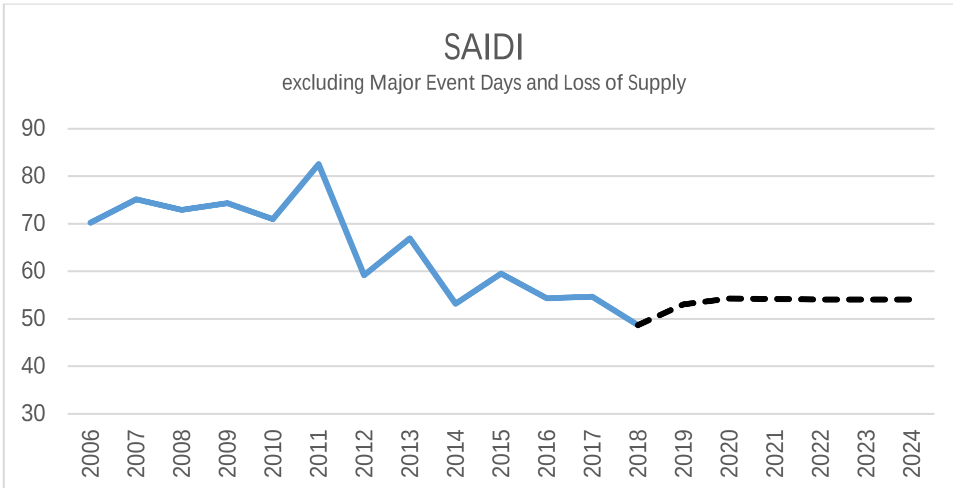


Figure 2: SAIDI Projections for 2019-2024 (excluding MED and LoS)

c) Please see Table 1. Please note that:

1. 2018 performance is considered to be an outlier due to performance in some cause codes (e.g. Lightning and Scheduled Outages for SAIFI) and the exclusion of five major event days (i.e. 1.4 percent of the year) from the statistics.

2. The projections reflect expected trends for performance and are not intended to be targets. Toronto Hydro's experience has been that due to considerable volatility from one year to the next with specific cause codes – including Tree Contacts, Adverse Weather, Foreign Interference, Human Element, and Unknown – it is very likely that actual performance will fall within a broader band than illustrated by the charts in part (a) and (b). For example, volatility experienced between 2015 and 2018 suggests that performance may vary by as much as, or more than, 10 percent from one year to the next. Please see

Exhibit U, Tab 1B, Schedule 1, pages 30 and 31 for additional details in respect of cause code volatility and trends.

Table 1: SAIDI and SAIFI Data for Figure 1 and Figure 2

Year	SAIFI Historical	SAIFI Projection	SAIDI Historical	SAIDI Projection
2006	1.84		70.21	
2007	1.77		75.12	
2008	1.66		72.89	
2009	1.49		74.33	
2010	1.53		70.94	
2011	1.48		82.53	
2012	1.28		59.20	
2013	1.34		66.92	
2014	1.18		53.19	
2015	1.31		59.49	
2016	1.28		54.34	
2017	1.18		54.64	
2018	1.14		48.67	
2019		1.19		53.03
2020		1.21		54.26
2021		1.21		54.16
2022		1.20		54.06
2023		1.20		54.02
2024		1.19		54.06

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 21, 2019

4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly owns two subsidiaries:

- LDC – distributes electricity and engages in CDM activities; and
- TH Energy – provides street lighting and expressway lighting services in the City.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

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

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $4.7 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 772,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's electricity distribution system is serviced from 1 control centre, 34 terminal stations and 1 transmission system terminal station, and is comprised of approximately 17,400 primary switches, approximately 60,560 distribution transformers, 146 in-service municipal substations, approximately 15,515 circuit kilometres of overhead wires supported by approximately 179,400 poles and approximately 13,207 circuit kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition (SCADA) systems to monitor, operate, sectionalize and restore the electricity distribution system.

(ii) *Terminal Stations*

LDC receives electricity at 34 terminal stations at which high voltage is stepped down to distribution-level voltages. These terminal stations contain power transformers and high-voltage switching equipment that are owned by Hydro One. These terminal stations also contain equipment such as circuit breakers, switches and station busses.

(iii) *Transmission System Terminal Stations*

LDC receives electricity at Cavanagh transmission system terminal station at which high voltage is stepped down to distribution-level voltages. The transmission system terminal station contains power transformers, high-voltage switching equipment, and low-voltage equipment such as circuit breakers, switches and station busses that are owned by LDC.

One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City. Copeland Station will be considered a transmission system terminal station.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. It will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During 2018, the testing on high voltage cable, the protection and control equipment, and the supervisory control and data acquisition system were all completed. The Corporation received approval from HONI, the electricity transmission provider, and the IESO for energization of the project and successfully energized one of two Copeland Station power transformers with associated cables and switchgear. The second power transformer and associated switchgear is anticipated to be energized in the first half of 2019 following the HONI's completion of additional servicing to some of their equipment. As at December 31, 2018, the cumulative capital expenditures on the Copeland Station project amounted to $202.6 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. The total capital expenditures required to complete the project has increased from $200.0 million to approximately $204.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See Part 8 under the heading "Risk Factors" below for further information on the Copeland Station project.

(iv) *Distribution Transformers and Municipal Substations*

Electricity at distribution voltages is distributed from the terminal stations to distribution transformers that are typically located in buildings or vaults or mounted on poles or surface pads that are used to reduce or step down voltages to utilization levels for supply to customers. The electricity distribution system includes approximately 60,560 distribution transformers. The electricity distribution system also includes 146 in-service municipal substations that are located in various parts of the City and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(v) *Wires*

LDC distributes electricity through a network comprised of an overhead circuit of approximately 15,515 kilometres supported by approximately 179,400 poles and an underground circuit of approximately 13,207 kilometres.

(vi) *Metering*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. LDC owns the meters and is responsible for their maintenance and accuracy.

As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the Competitive Sector Multi-Unit Residential rate class. As at December 31, 2018, LDC had installed approximately 77,000 Unit Smart Meters in these types of multi-unit complexes.

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2018	**LDC 2017**	**CEA 2017[1]**
SAIDI	0.98	0.99	7.15
SAIFI	1.48	1.43	2.53
CAIDI	0.66	0.69	2.82

Note:

(1) Data was extracted from the CEA's 2017 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2018 has not been published by the CEA.

TORONTO HYDRO® Corporation

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

March 29, 2018

4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly-owns two subsidiaries:

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The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $4.4 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 768,000 customers located in the City. LDC serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's electricity distribution system is serviced from 1 control centre, 34 terminal stations and 1 transmission system terminal station, and is comprised of approximately 17,350 primary switches, approximately 60,540 distribution transformers, 153 in-service municipal substations, approximately 15,540 kilometres of overhead wires supported by approximately 178,800 poles and approximately 13,220 kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition (SCADA) systems to monitor, operate, sectionalize and restore the electricity distribution system.

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One of LDC's largest capital initiatives currently in progress is the construction of Copeland Station in response to the developing need for distribution solutions in the downtown core of the City. Copeland Station will be considered a transmission system terminal station.

Copeland Station will be the first transformer station built in downtown Toronto since the 1960's and will be the second underground transformer station in Canada. It will provide electricity to buildings and neighbourhoods in the central-southwest area of Toronto. During 2017, major electrical equipment including power transformers and high and medium voltage switchgear, medium voltage cable, control wiring and DC systems was installed, tested and commissioned and high voltage cable was installed. The electric station service equipment was installed and energized. Protection and control equipment was installed and testing and commissioning commenced. In addition, the machine shop installation and landscaping were completed and sidewalks and roadway were paved. Hydro One, the electricity transmission provider, commenced the installation of their equipment, including high voltage switchgear and protection and control equipment. As at December 31, 2017, the cumulative capital expenditures on the Copeland Station project amounted to $195.1 million, plus capitalized borrowing costs. All capital expenditures related to Copeland Station are recorded to PP&E. The total capital expenditures required to complete the project are approximately $200.0 million, plus capitalized borrowing costs. There may be additional unforeseen delays and expenditures prior to completion of the project. See Part 8 under the heading "Risk Factors" below for further information on the Copeland Station project.

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As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the Competitive Sector Multi-Unit Residential rate class. As at December 31, 2017, LDC had installed approximately 74,000 Unit Smart Meters in these types of multi-unit complexes.

(vii) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and the CEA for the twelve month periods ending December 31 in the years indicated below.

	LDC 2017	**LDC 2016**	**CEA 2016 (1)**
SAIDI	0.99	0.95	4.39
SAIFI	1.43	1.40	2.78
CAIDI	0.69	0.68	1.58

Note:

(1) Data was extracted from the CEA's 2016 Service Continuity Report on Distribution System Performance in Electrical Utilities, excluding significant events. At the date of this AIF, such report for the year 2017 has not been published by the CEA.

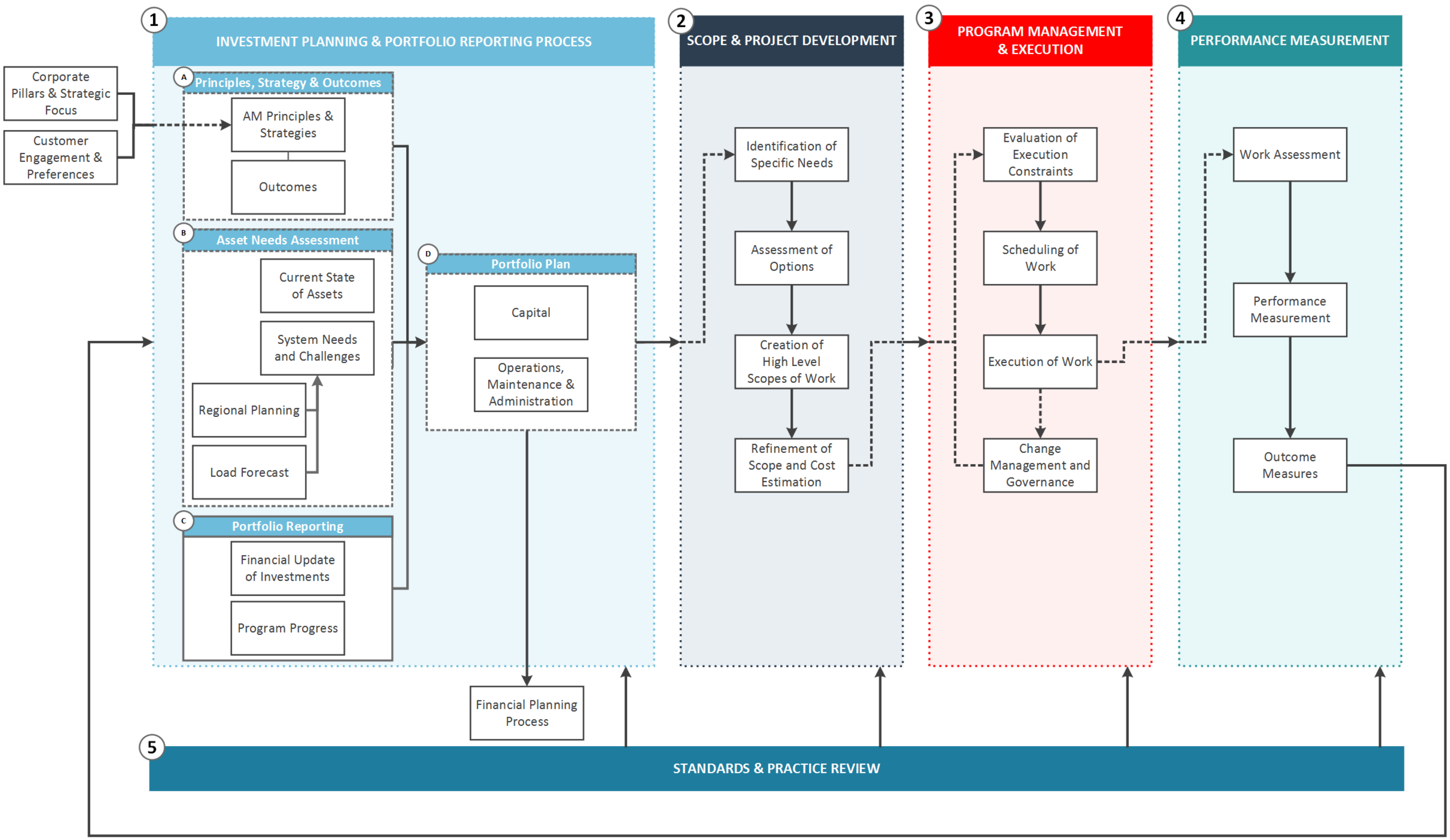


Figure 2: Asset Management Process Overview

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 1B, Tab 1, Schedule 1

THESL has filed and Executive Summary and Business Plan Overview. Please file the actual 2020-2024 Business Plan approved by the THESL Board. Please provide a detailed description of the Business Planning process.

RESPONSE:

The Business Plan that underpins this Application and that was approved by the Board of Directors is filed at Appendix A to interrogatory 1A-CCC-1. As this was the final Business Plan leading to the eventual filing of Toronto Hydro's rate application, it included the penultimate forecasted capital expenditure plan for the full 2020-2024 period. As explained in the following description of business planning, the 2018-2020 Business Plan was a corporate deliverable within the business planning process that led to the final plan filed in this application.

<u>Toronto Hydro's Business Planning Process for the 2020-2024 Custom IR Application</u>

1. Beginning in late 2016, Toronto Hydro generated a high-level assessment of its operational needs, and undertook a first phase of customer engagement to receive feedback on customer needs and priorities. Please see Exhibit 1B, Tab 3, Schedule 1, for more details about Toronto Hydro's Phase 1 Customer Engagement.

2. The utility considered the results of this first phase of customer engagement alongside its legal obligations and business input to set its outcomes framework and high-level planning parameters in early 2017.

3. Next, Toronto Hydro proceeded with its operational planning and financial planning (i.e. budgeting) processes, building out and refining a business plan and strategic parameters for 2018-2024 that was completed in November 2017.

4. Toronto Hydro then took this plan back to customers in April and May of 2018, including a detailed breakdown of the plan. Please see Exhibit 1B, Tab 3, Schedule 1, for more details about Toronto Hydro's Phase 2 Customer Engagement.

5. Taking into account the feedback received in this second phase of Customer Engagement, the utility made additional refinements and adjustments to the plan, including changes to shift funding between certain programs to better reflect customer preferences. The supporting evidence was finalized and the application filed in August 2018. Please see Exhibit 2B, Section E2.3.2.3 and Toronto Hydro's response to interrogatory 2B-Staff-71, parts (a) and (b) for more details about changes Toronto Hydro made to its plan to reflect customer feedback received during Phase 2.

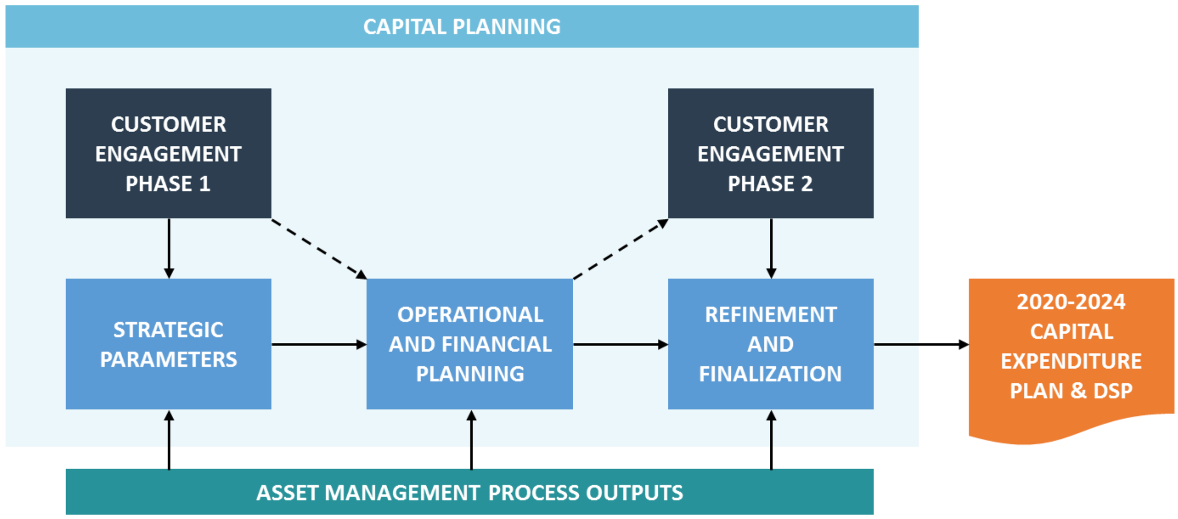


Figure 1: Capital Planning in Business Planning

The following sections provide an overview of how the elements of business planning came together to generate the capital plan that forms the basis of Toronto Hydro's 2020-2024 Distribution System Plan.

E2.1.1 Customer Engagement and Strategic Parameters

Toronto Hydro began business planning by engaging customers (i.e. Phase 1 of Customer Engagement) and using the feedback received to help set the initial strategic parameters for the business planning horizon. Feedback from customers was that price, reliability, and safety were their top three priorities. Overall, most customers preferred prices be kept as low as possible while maintaining average reliability performance and improving reliability for customers experiencing below-average service. [1]

With consideration for customers' priorities and preferences and other inputs (discussed below), Toronto Hydro set the following strategic parameters for the capital plan:

1) **Price Limit:** Toronto Hydro set an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates.[2]
2) **Capital Budget Limit:** Toronto Hydro set an upper limit of $562 million for the average annual capital plan budget, which corresponded with capping infrastructure and operations

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Section E2.3.
[2] As calculated for the monthly bill of a Residential customer using 750 kWh.

spending predominantly at sustainment levels. As discussed in Section E2.2, this upper limit was based on an assessment of system and operational needs as derived from the utility's asset management processes, reflecting the need to, at a minimum, meet the utility's service obligations, maintain average reliability performance, and sustainably manage asset risk over the long-term while mitigating material safety and environmental risks.

3) **Performance Objectives:** Toronto Hydro developed an Outcomes Framework that aligned with the utility's corporate strategic pillars and the *Renewed Regulatory Framework*, establishing a lens through which the utility could express its plans and performance in terms that demonstrate value for customers, and are meaningful to its operations. This framework is summarized in Figure 2, below.

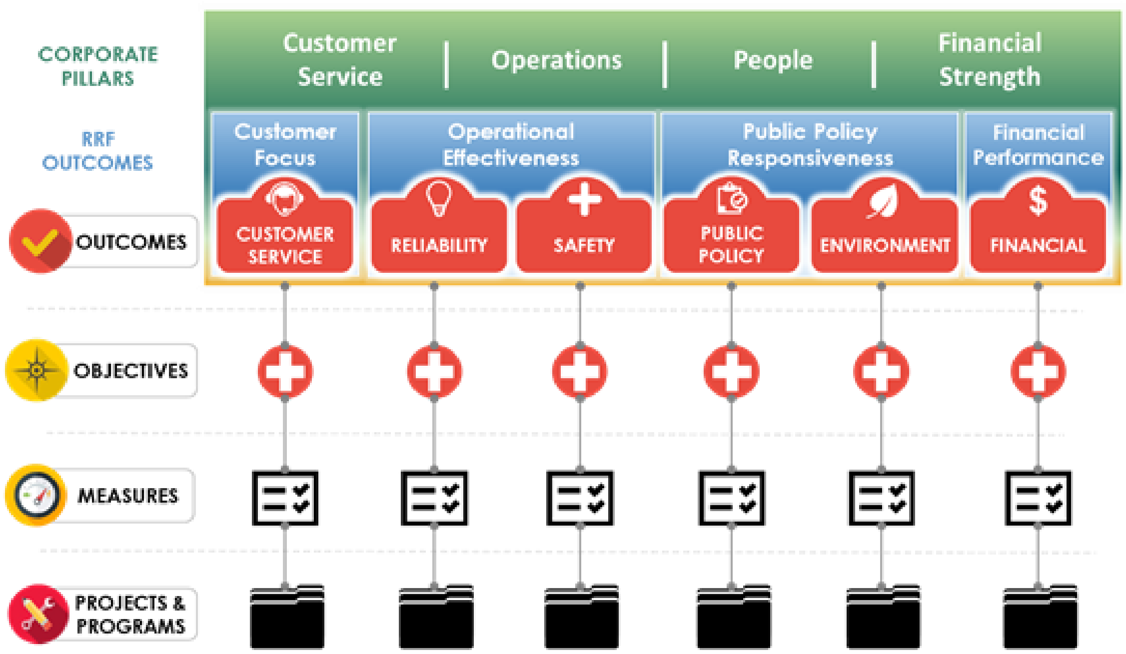


Figure 2: Toronto Hydro's Customer-Focused Outcomes Framework[3]

In developing these strategic parameters, Toronto Hydro considered a number of inputs, including:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;

[3] The RRF Outcomes are aligned alongside Toronto Hydro's Outcomes based on the definitions provided by the OEB in the Utility Rate Handbook. It should be noted that Toronto Hydro's Financial outcome includes cost-related components that the OEB would classify within the Operational Effectiveness outcome.

- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system performance;
- projected system use profiles and pressures;
- long-term asset stewardship needs;
- safety and environmental risk assessments;
- evolving business conditions and the emergence of new technologies;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including ongoing and anticipated upward pressure on construction costs in Toronto;
- total cost benchmarking; and
- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary planning scenarios for each capital program. These scenarios – described further in Section E2.2 – reflected a baseline “sustainment” level of system investment, an “improvement” level, and an “accelerated improvement” level. Figure 3, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the sustainment, improvement, or accelerated improvement options for every investment program. The three lines represent a fully unconstrained budget on the high-end, a minimal system sustainment budget on the low end, and a mid-point budget in between.

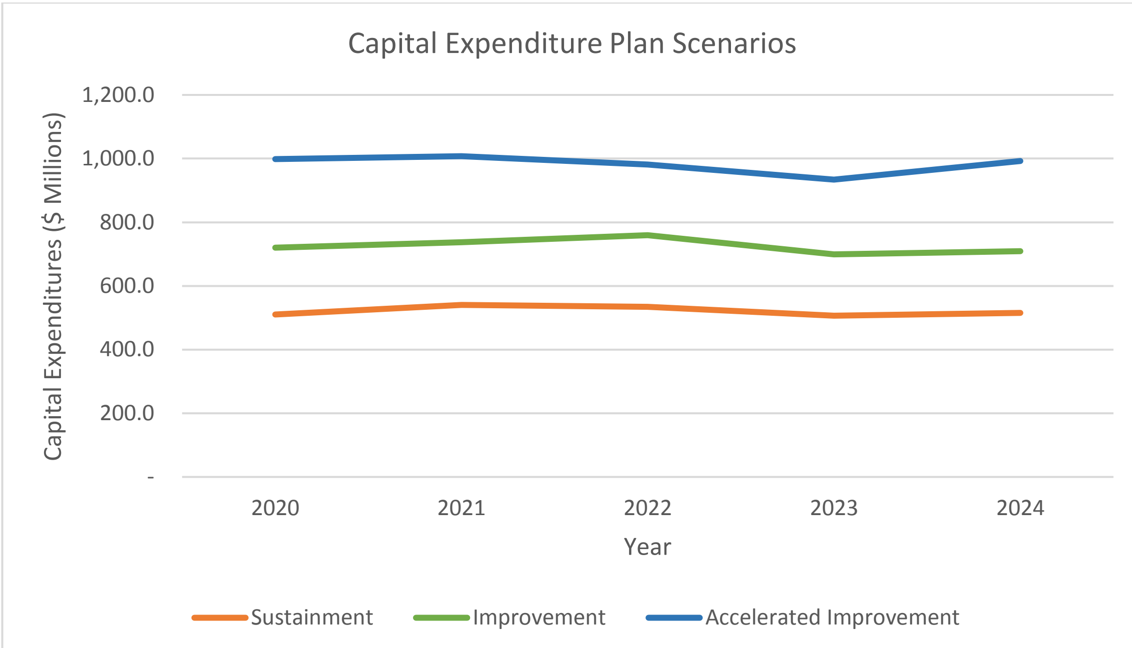


Figure 3: Preliminary High-level Capital Expenditures Scenarios

Toronto Hydro set its $562 million average annual capital budget limit to align predominantly with the "sustainment" level of investment. This level of investment best reflected the need to balance long-term system investment needs with customers' service needs and their general preference for minimizing rate increases.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2020-2024. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with short- and long-term asset management ("AM") objectives, while remaining within the financial constraints and considerations set-out in the strategic parameters. A key feature of this planning stage was the formal integration of the utility's customer-focused Outcomes Framework. This helped to ensure that the organization's bottom-up expenditure plan proposals were directly informed by Customer Engagement results and were consistently translated into outcomes that matter to customers.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic AM objectives. From this starting point, an iterative process generated multiple versions of the

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 5:

Reference(s): Exhibit 1B

Please provide a step-by-step explanation of the Toronto Hydro budgeting process that led to the 2020-2024 plan, as well as the annual budgeting process after a subsequent Board decision on the plan. Please explain how these processes have changed since its last Custom IR application.

RESPONSE:

The budgeting process that led to the 2020-2024 plan presented in this Application is the operational and financial component of the broader business planning process detailed in Toronto Hydro's response to interrogatory 1B-CCC-9. The below provides further details regarding step 3 in the process set out in 1B-CCC-9.

In general, this process has matured since the utility's last Custom IR application in tandem with the evolution of the OEB's customer engagement requirements under the Renewed Regulatory Framework.

As noted in evidence at Exhibit 1B, Tab 1, Schedule 1 and in the response to interrogatory 2B-SEC-47, the utility initiated the budgeting process by setting the strategic parameters, including budgetary limits and performance objectives, with regard to the feedback received from customers. Toronto Hydro set the strategic parameters in order to be responsive to: the utility's legal requirements including safety, customer feedback, and business input through expert analysis and professional judgment to develop construction and operations programs that address technical and operational requirements. The annual budgeting process is an iterative one and began with setting the strategic direction for the development of the operational and capital plans and budgets to be executed over the planning horizon.

As discussed in Exhibit 1B, Tab 3, Schedule 1, customers expressed that limiting price increases and specific performance outcomes were important to them. Both of these were also important to Toronto Hydro. To help operationalize these parameters for budgeting purposes, Toronto Hydro also expressed the price increase in approximate OM&A and CapEx terms as a third strategic parameter.

Toronto Hydro developed bottom-up capital and operational budgets to address the needs of the utility and meet the objectives, being guided by considerations such as customer feedback, legal and regulatory requirements, subject matter expertise, business judgment, benchmarking, third party analysis, and analytics of various types.

As the capital and operational plans and budgets matured through the process, the needs and cost pressures of the business pressed against the budgetary limits that were set at the outset of the process. The budgeting process involved calibration to strike a balance between these two elements.

The ultimate budget fed into the Business Plan, presented to Toronto Hydro's Board of Directors for final approval. A copy of the Business Plan that underlies this application is filed as Appendix A to interrogatory 1B-CCC-9.

Ontario

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2014-0116

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

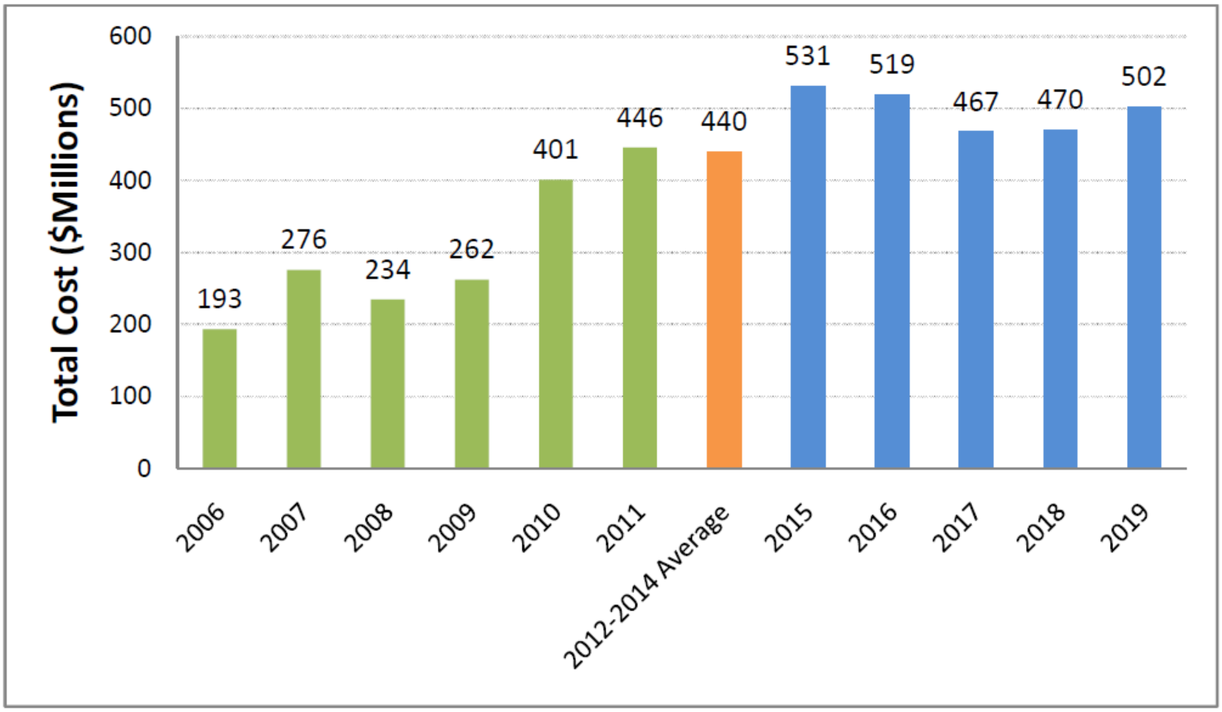
Application for electricity distribution rates effective from May 1, 2015 and for each following year effective January 1 through to December 31, 2019

BEFORE: Christine Long
Presiding Member

Ken Quesnelle
Vice Chair and Member

Cathy Spoel
Member

December 29, 2015



These expenditures total just under $2.5 billion for the five-year period of the DSP.

Toronto Hydro stated that it was confident that it can execute the proposed capital plan arguing that its successful delivery of the 2012-2014 ICM program is the best evidence of its ability to deliver a capital program of the size and complexity contained in the Application. It stated that it is proposing four specific measures to track and evaluate cost efficiency of executing its DSP: (a) Engineering, Design and Support Costs, (b) Materials Handling on-Cost, (c) Contractor Cost Efficiency and (d) Asset Assemblies Framework.

Productivity outcomes will be shared with customers throughout the duration of the plan in the form of more cost-effective assets being placed into service and reinvestment into the system.

Toronto Hydro stated that it considers age, condition, customer impacts and other asset-specific information in its capital planning.

Intervenors and OEB staff generally argued that Toronto Hydro had not adequately supported a $2.5 billion capital plan.

Their objections included:

- Inadequate evidence of the need and prioritization of the proposed programs

- Reliability and outage trends do not support the capital investment levels proposed in the Application, as Toronto Hydro's evidence showed an improvement in reliability during a period in which Toronto Hydro was spending considerably less than proposed for the next five years.
- Rate impacts on customers
- Assets proposed for replacement are not aligned with the recent results of Toronto Hydro's asset condition assessments.

Intervenors also submitted that the OEB should require Toronto Hydro to undertake various studies and/or filings related to the implementation of the DSP during the Custom IR period.

Toronto Hydro took the position that the objections of the intervenors were not supported by the evidence and were based on the mistaken assumptions that Toronto Hydro has moved from condition based to age based planning and that using asset age in planning leads to premature replacements.

There was no consensus amongst OEB staff and intervenors as to an appropriate level of spending. Suggested levels ranged from $400 million to about $480 or $490 million per annum. Some intervenors argued that there should be much reduced spending on system renewal. SEC argued that, the OEB should significantly reduce Toronto Hydro's proposed capital plan and apply a productivity formula to the capital budget.

Toronto Hydro argued that due to the integrated nature of the DSP, it is not practical from a project management or work execution perspective to arbitrarily reduce spending in various categories or programs and an overall reduction in approved capital expenditures would require a re-evaluation of the capital plan.

Toronto Hydro also submitted that there is no simple correlation between system-wide reliability and total expenditures and the relationship is much more complex and nuanced.

Findings

The OEB will not accept the capital budget as requested by Toronto Hydro. An annual reduction of 10% to the proposed capital spending is required.

Toronto Hydro presented three possible approaches to its DSP capital spending.

1. The Economically Optimal Approach – Capital spend of $2.560B in the first year
2. The Accelerated 5 year Pacing – Capital spend of $840M for two years, $830M for the next three
3. The Paced Approach – the Application filed with the OEB.

Toronto Hydro's evidence did not include a full slate of reasonable funding requests as set out in the Economically Optimal Approach. Instead it chose the "Paced Approach" in order to balance operational and customer needs with consideration of rate impacts. The proposed Paced Approach contemplates capital spend of an average of $498M per year over the plan period. Toronto Hydro states that this is the "minimal level of investment that is appropriate given the magnitude of the asset backlog and other critical system issues and operational needs that the utility faces."[11] The OEB disagrees.

As a general principle, the OEB accepts that the DSP represents a comprehensive approach to capital planning by Toronto Hydro over the next five years. Generally, the OEB does not take issue with the content of the DSP. The OEB's concerns in respect of the approach proposed by Toronto Hydro fall into two categories;

1. Asset Replacement Rate
2. Productivity Improvements

Asset Replacement Rate

Toronto Hydro's proposal is largely supported by an asset condition analysis as opposed to a reliability impact assessment. Choices about spending are driven by assets, rather than based on services. Toronto Hydro considers the reliability impact to be an outfall of its asset replacement program.[12] The optimization tool, while very useful in providing the economic analysis of when to change out a particular asset does not give a clear indication of how the overall spend is directly correlated to the customer experience.

Toronto Hydro states that its response to manage the renewal of the backlog of end-of-life useful assets is guided by a lifecycle cost reduction policy. Toronto Hydro says that it can minimize costs, including customer interruption costs by replacing assets at the economic end of life.[13] Toronto Hydro defines an asset's economic end-of-life as being when the total life cycle cost, defined as the sum of the annualized risk cost and the annualized capital cost, is at its lowest. This is considered to be the optimal intervention time. The annualized risk cost which increases as the asset ages, represents the quantifiable costs of asset failure (including customer interruption costs) multiplied by the probability of failure. The annualized capital cost, which decreases as the asset ages, represents the capital cost of replacement, annualized over the asset's life.

[11] EB-2014-0116 Toronto Hydro-Electric System Limited *Argument in Chief Compendium,* p. 19.
[12] Transcript, Vol. 9, p. 189, L 4-7.
[13] EB-2014-0116 Toronto Hydro-Electric System Limited *Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges,* July 31, 2014, E 2B, S D3.

Several parties raised the concern that assets were being replaced too soon and that asset age was driving system renewal. Currently 26% of Toronto Hydro assets are beyond their useful lives. Despite a push on asset renewal since 2011, 26% is an increase from 22% beyond useful lives in 2011. Toronto Hydro explained that 33% of its assets will be beyond their useful lives by the end of the 5 year plan if the utility does not take a proactive approach and allows the assets run to failure. Toronto Hydro's objective is to reduce the backlog so that it can achieve a "steady state" where the percentage of assets beyond useful lives does not increase.

Toronto Hydro's evidence shows the following:

Year	% Assets not at end of life	% Assets past end of life	% Assets to reach end of life by 2020
2011	71	22	7 (between 2011-2016)
2015	67	26	7

Toronto Hydro argues that the useful life of an asset is the mid-point between the Kinetrics Minimum Useful Life and Maximum Useful Life for a specific asset type. By

definition, assets that are approaching or have surpassed this mid-point have reached an age when a majority of those assets typically fail and when the statistical probability of failure increases exponentially every year .[14] This leads to a higher cost to repair and replace than asset renewal. Toronto Hydro states that the Asset Condition Assessment Audit carried out by Kinectrics in 2014 shows a significant decline in the health of the system. Intervenors questioned whether this additional cost of later replacement was borne out by the evidence.

The OEB shares the concerns of the parties that the age of the assets may be too heavily weighted in the determination of end of useful life. Toronto Hydro concedes that age of the asset is the primary driver with respect to asset replacement. Toronto Hydro also states that asset condition does factor into the decisions they make in respect of asset replacement.

SEC drew the OEB's attention to Toronto Hydro's single largest program its Underground Circuit Renewal Program (E6.1). This program seeks to replace underground switches, transformers and cable at a cost of $459.3 over the five year term. Toronto Hydro plans to replace 1,667 underground transformers over the 5 years.

[14]Kinectrics report, p.9 of 29 of AIC

348 are scheduled to be replaced in 2015 alone. However the Asset Condition Assessment conducted by Kinectrics shows that in 2014 only 33 underground transformers are in poor or very poor condition, as show in the table below.[15] This is only one example, but it demonstrates the OEB's concern that there is too heavy an emphasis placed on asset age, rather than asset condition.

	Asset	% very poor	% poor	% fair	% good	% very good	% very poor & poor	# very poor	# poor	# fair	# good	# very good	# very poor & poor
1	Station Power	1.24%	13.64%	49.59%	23.14%	12.40%	14.88%	3	37	133	62	33	40
2	Station Switchgear	4.84%	36.69%	33.47%	9.27%	15.73%	41.53%	14	102	93	26	44	116
3	Air Blast Circuit	0.00%	3.89%	87.78%	2.78%	5.56%	3.89%	0	11	255	8	16	11
4	Air Magnetic Circuit	0.21%	4.72%	74.25%	18.88%	1.93%	4.93%	1	30	466	118	12	31
5	Oil Circuit Breakers	0.64%	10.19%	82.80%	6.37%	0.00%	10.83%	2	34	275	21	0	36
6	Oil KSO Breakers	0.00%	4.55%	81.82%	13.64%	0.00%	4.55%	0	3	48	8	0	3
7	SF6 Circuit Breaker	0.00%	0.00%	7.69%	46.15%	46.15%	0.00%	0	0	15	93	93	0
8	Vacuum Circuit	0.00%	0.21%	3.14%	10.25%	86.40%	0.21%	0	1	21	69	583	1
9	Submersible	0.00%	0.02%	6.68%	34.93%	58.36%	0.02%	0	2	638	3337	5576	2
10	Vault Transformers	0.00%	0.23%	23.48%	39.80%	36.50%	0.23%	0	30	3060	5188	4757	30
11	Padmounted	0.00%	0.02%	10.09%	43.51%	46.38%	0.02%	0	1	722	3115	3321	1
12	Padmounted Switches	0.00%	0.39%	7.20%	36.12%	56.30%	0.39%	0	3	58	290	452	3
13	3 Phase O/H Gang	0.00%	0.39%	3.01%	63.84%	33.15%	0.39%	0	4	33	707	367	4
14	3 Phase O/H Gang	0.00%	0.00%	15.38%	76.92%	7.69%	0.00%	0	0	2	12	1	0
15	SCADAMATE Switches	0.13%	0.00%	1.14%	57.34%	41.39%	0.13%	1	0	11	531	383	1
16	Wood Poles	2.34%	7.64%	44.13%	7.28%	38.61%	9.98%	2885	9419	54403	8975	47598	12303
17	Automatic Transfer	0.00%	16.98%	32.08%	30.19%	20.75%	16.98%	0	10	19	18	12	10
18	Network Transformers	0.00%	0.00%	16.40%	41.45%	42.14%	0.00%	0	0	310	784	797	0
19	Network Protectors	0.00%	0.00%	3.75%	32.25%	64.00%	0.00%	0	0	61	521	1034	0
20	Network Vaults	1.70%	8.80%	72.37%	16.08%	1.04%	10.50%	18	93	769	171	11	112
21	Cable Cambers	0.26%	1.60%	10.77%	50.17%	37.20%	1.86%	28	174	1174	5470	4056	203

Exhibit 2B Section D2 Appendix A: 2014 Audit Results By Asset Class[16]

Toronto Hydro stated in its evidence that the asset condition or health index of an asset would only be used to accelerate the replacement of an asset but the inverse was not true. The better than expected condition of an asset does not factor into the model to delay the replacement of the asset[17]. The OEB is of the view that actual asset condition rather than calculated "end of life" should be the primary determining factor when an asset should be replaced.

Toronto Hydro states that capital replacement is the cornerstone of the Application. Therefore the OEB finds that Toronto Hydro's approach should include more emphasis

[15] School Energy Coalition Toronto Hydro Rates 2015-2019 EB-2014-0116 *Final Argument, p.34.*
[16] SEC Final Argument, p. 37,April 3, 2015
[17] EB-2014-0116 Transcript, Vol. 4, p.140, L 60- 61

on asset condition in the assessment of when a steady state of asset renewal should be achieved. This will require some changes to the proposed capital plan.

Productivity Improvements

The OEB has consistently been clear that distributors need to strive to increase productivity. The OEB has specifically stated that custom applications require that applicants demonstrate productivity improvements. The OEB is not satisfied that Toronto Hydro has incorporated adequate productivity improvements within the Application.

In its evidence, Toronto Hydro relies upon the fact that 81% of capital project jobs are sourced externally and cites this alone as the mechanism which drives efficiency and productivity gains. Toronto Hydro explained that it relies upon a competitive process to cost projects. It provided the example of 6400 units of work being bid with 81% of the costs associated with the capital work program being determined through a competitive process. Four elements make up the type of work bid; materials, civil engineering, electrical design and construction work. The procurement is based on qualified bidders offering individual fixed prices for various units of work. Toronto Hydro explained their rationale as follows:

> "once contractors are selected on the basis of their qualifications and overall pricing, they are not guaranteed any particular amount of work. Instead contractors are assigned to individual projects based on their cost to complete each project so that the lowest priced contractor for a particular project gets the work"[18]

Toronto Hydro advanced that the process leads to the best value, while satisfying the operational needs of the utility.

The OEB is concerned that this method of costing may not in fact lead to efficiencies. Competitive bidding for unit cost contracting is not in itself a sufficient demonstration of productivity improvements. For example, Toronto Hydro does not seem to benefit from any of the efficiencies gained by contractors as they undertake similar projects over the period of the plan..

The OEB is not satisfied that bidding 81% of work to a competitive market is sufficient to ensure continuous productivity improvement. While Toronto Hydro provided some evidence on cost containment in respect of negotiated labour rates and performance tracking of its internal staff, it relies heavily on external contractors to achieve productivity improvements. Many parties argued that that Toronto Hydro was lagging in

[18] Transcript, Vol. 6, pp. 98-108.

productivity, especially when benchmarked against other utilities. Based on the benchmarking results, the OEB does not accept that there are no further productivity gains that can be made over the next five years. The OEB finds that Toronto Hydro must place more emphasis on productivity gains and that Toronto Hydro must find efficiencies over the five years of the capital plan.

Length of the Planning Horizon

The OEB has approached the planning horizon in this Custom IR application by considering the five year horizon as is contemplated in the RRFE. The evidence provided does not convince the OEB that any changes need to be made and the OEB accepts the five years planning horizon that is proposed by Toronto Hydro. The OEB will not require Toronto Hydro to come back to the OEB after two years as was suggested by an intervenor. The OEB has determined that Toronto Hydro has met the RRFE criteria for a custom application, one of which is a requirement for a 5 year plan supported by a DSP. It is in the context of this 5 year plan that the OEB has made its determinations in this case. The OEB also disagrees with Dr. Kaufman that the capital projects should be extended over an 8 year period. Dr. Kaufman was not qualified as an expert in distribution system planning, and the OEB is satisfied that Toronto Hydro has a plan to be able to complete projects within the five years and that it will ensure that it is physically equipped to undertake the work as it has successfully managed large capital programs over the last few years. The OEB is generally satisfied with Toronto Hydro's DSP and rejects the notion that Toronto Hydro's DSP requires oversight by an independent engineer.

Reliability

Benchmarking

PEG suggested that the reliability benchmarking provided by Toronto Hydro should not be accepted by the OEB. PEG disagreed with the information sources which form the basis of the benchmarking.

While the experts used different information in coming to their conclusions, the OEB notes that both PEG and PSE agree that SAIFI (the frequency of outage measure) performance is below what is expected. The experts disagree on the SAIDI measure (the outage duration measure). PSE states that Toronto Hydro's measure is well below expected measures, while PEG finds that SAIDI is not statistically different from expected levels.

While the OEB does consider the relationship between a distributor's costs and its reliability performance to be important from a regulatory standpoint, at this point, the

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LEGEND	
(light peach)	EB-2014-0116 Application Numbers Verified
(orange)	EB-2014-0116 Application Numbers Unverified & Corrected Accordingly within this IR Response
(light yellow)	Data Populated

	Program/Assets		EB-2014-0116 Application						Actual/Forecast						EB-2018-0105 Proposal					
			2015	2016	2017	2018	2019	Total	2015	2016	2017	2018	2019	Total	2020	2021	2022	2023	2024	Total
E6.1	Underground Circuit Renewal																			
		Underground Switches	84	71	74	88	88	*405*	47	79	87	39	28	*280*	49	45	45	46	46	*231*
		Underground Transformer	348	291	305	362	361	*1667*	105	710	740	251	264	*2070*	407	380	380	387	387	*1941*
		Underground Cable (circuit km)	150	126	132	156	156	*720*	105	442	173	156	131	*1007*	103	96	96	98	98	*491*
E6.2	Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers																			
		PILC Cable (km)	5.39	3.66	2.59	2.66	0.7	*15*	1.8	2.3	2	0	0	*6.1*	2.9	5.1	5.3	7.1	7.1	*27.5*
E6.3	Underground Legacy Infrastructure																			
		Sachsenwerk Switch and Fuse Units	6	12	12	10	0	*40*	22	2	6	3	10	*43*	Remaining locations to be addressed through Underground System Renewal					
		Powerlite Switches	0	2	2	2	2	*8*	2	1	0	1	3	*7*						
		Single Phase Submersible Transformers	0	4	4	4	4	*16*	0	0	0	0	16	*16*						
		Step Transformers	0	2	2	2	1	*7*	0	0	1	1	3	*5*						
		Transclosures	6	9	9	9	9	*42*	0	9	6	1	20	*36*						
		SF Switches	2	1	2	1	0	*6*	2	0	1	0	2	*5*						
		Cable Chamber Covers	25	375	375	375	350	*1500*	0	0	9	79	79	*167*	200	200	200	200	200	*1000*
E6.4	Overhead Circuit Renewal																			
		Poles	3332	1735	1900	1934	2313	*11214*	3656	2692	1513	1510	1330	*10701*	2230	2230	2220	2400	2450	*11530*
		Overhead Switches	294	160	166	154	207	*981*	192	167	120	90	13	*582*	130	130	130	160	160	*710*
		Overhead Transformers	972	511	478	598	673	*3232*	940	769	441	412	310	*2872*	1300	1300	1300	1400	1400	*6700*
E6.5	Overhead Infrastructure Relocation																			
		Poles		32		27	8	*67*	81	0	7	11	8	*107*	Remaining locations to be addressed through Overhead System Renewal					
		OH Conductor (mts)		5656			3400	*9056*	12432	0	455	244	0	*13131*						
		OH Switches		10		6	6	*22*	83	0	10	1	9	*103*						
		OH Transformers		22		1		*23*	43	0	3	1	4	*51*						
		Underground Cable Chamber	2		18			*20*	0	5	3	5	0	*13*						
		Underground Duct (mts)	110		3000	165	200	*3475*	144	251	524	1541	0	*2460*						
E6.6	Rear Lot Conversion																			
		Pole	63	218	110	31	175	*597*	See Notes for 2B-SEC-51. 2,090 customer conversions			173 customer conversions	84 customer conversions	*2347 customer conversions*	See Notes for 2B-SEC-51. 2,350 customer conversions.					*2350 customer conversions*
		Transformer	33	62	48	30	40	*213*												
		Manual Switch	16	14	7	5	8	*50*												
		Fuse	13	15	16	20	19	*83*												
		Riser	13	5	6	5	22	*51*												
		Conductor (m)	1910	9314	4632	1796	7886	*25538*												
		Cable (m)	4583	4305	5476	5598	1566	*21528*												
E6.7	Box Construction Conversion																			
		OH Transformer	201	381	86	175	77	*920*	2422 Poles			586 poles	1060 poles	*4068 poles*	4,100 poles					*4100 poles*
		OH Switch	162	301	70	176	85	*794*												
		Poles	407	780	277	255	117	*1836*												
		UG Switch	0	0	0	6	0	*6*												
		UG Transformer	21	27	9	52	17	*126*												
		OH Conductor (km)	25.5	46.2	11.4	24.4	11.5	*119*												
		UG Cable (km)	6	10.4	1.5	5.8	1.4	*25.1*												
E6.8	SCADA-MATE R1 Replacement																			
		R1 Switch	72	67	57			*196*	40	18	31	87	31	*207*	0	0	0	0	0	*0*
		RTU	52	49	14			*115*	76	19	47	17	15	*174*	0	0	0	0	0	*0*
E6.9	Network Vault Rebuild Program																			
		Vaults	6	9	9	9	9	*42*	34			11	18	*63*	33					*33*
		Roofs	4	2	2	3	4	*15*												
		UG Network Units	11	18	17	20	20	*86*	See Network Unit (Transformer and Protector)						0	0	0	0	0	*0*
E6.10	Network Unit Renewal Program																			
		Network Unit (Transformer and Protector)	40	50	50	50	50	*240*	17	25	21	11	18	*92*	40	40	40	40	40	*200*

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LEGEND	
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(light yellow)	Data Populated

	Program/Assets	EB-2014-0116 Application						Actual/Forecast						EB-2018-0105 Proposal					
E6.11 Legacy Network Equipment Replacement (ATS & RPB)							*0*												
	ATS	3	2	3	2	3	*13*	3	3	9	18	7	*40*	5	5	3	0	0	*13*
	RPB	0	2	2	2	2	*8*												
E6.12 Network Circuit Reconfiguration																			
	UG Transformers **(600 V Network)**		8				*8*	0	0	2	1	2	*5*	5					*5*
E6.13 Stations Switchgear Renewal																			
	TS Switchgear	0	3	2	2	2	*9*	0	0	1	1	1	*3*	0	0	1	3	1	*5*
	MS Switchgear	3	4	2	1	1	*11*	2	0	4	3	2	*11*	3	3	2	2	2	*12*
E6.14 Stations Power Transformer Renewal																			
	Power Transformers	5		19			*24*	2	0	6	3	5	*16*	2	2	2	2	2	*10*
E6.15 Stations Circuit Breaker Renewal																			
	KSO Oil Circuit Breaker	10	6	6	7	6	*35*	4	2	5	8	7	*26*	1	1	2	2	3	*9*
E6.16 Stations Control & Monitoring																			
	Etobicoke RTU Replacement **(MOSCAD)**	2	5	5	5	5	*22*	1	5	7	6	5	*24*	3	3	3	3	3	*15*
	Scarborough SCADA Installation	0	2	2	2	1	*7*	0	0	2	1	2	*5*	1	1	1	1	2	*6*
	Downtown RTU Replacement **(DACSCAN)**	0	1	1	2	2	*6*	0	0	0	1	2	*3*	1	3	3	3	4	*14*
	Pilot-wire Relay Upgrade	0	6	10	12	12	*40*	0	0	1	1	3	*5*	1	1	1	1	1	
E6.17 Stations Ancillary Systems																			
	Air Compressors	4			2		*6*	0	0	0	0	0	*0*	0	2	0	0	0	*2*
	Station Service Power Supply		1				*1*	0	0	1	0	2	*3*	0	0	2	2	2	*6*
	Fire Alarm System			2	1	2	*5*	0	0	1	0	1	*2*			5			*5*
	Fire Barrier/Suppression System	1	2				*3*	0	0	0	1	1	*2*	0	0	0	0	0	*0*
E6.18 Stations Buildings																			
E6.19 Stations DC Battery Replacement																			
	Battery System 50 Ah	2	8	5	6	5	*26*												
	Battery System 80 Ah					1	*1*												
	Battery System 100 Ah	3	8	7	5	7	*30*	3	9	13	13	10	*48*	11	13	13	15	15	*67*
	Battery System 200 Ah			1			*1*												
	Battery System 300 Ah		1	2	2		*5*												
	Battery System 400 Ah	1	1			2	*4*												
E6.20 Reactive Capital																			
	Smart Meteres	3930	3930	3930	3930	3930	*19650*	3247	3004	4058	5350	3930	*19589*						
	RIMS	88	88	88	88	88	*440*	108	66	53	178	88	*493*	5585	5685	5785	5885	5985	*28925*
	Quadlogic	1057	1157	1257	1357	1457	*6285*	1004	2233	1117	1172	1457	*6983*						
	Primary Metering Units	8	10	10	10	10	*48*	3	23	6	8	10	*50*						
E6.21 Worst Performing Feeder																			
E6.22 Distribution System Communication Infrastructure																			
	IP Data Network Retro-fit (SONET Multiplexers to be augmente	34	11				*45*	0	0	0	0	0	*0*						
	IP Data Network Installation (Without SONET technology Present) (Number of sites)		34				*34*	0	0	0	0	0	*0*			45			*0*
	Fiber-Optic Ring Fiber replacement in Toronto (km)	72					*72*	0	21	50	8	0	*79*						
	Fiber-Optic Ring Fiber replacement in Scarborough (km)	45					*45*	54	31	0	10	0	*95*	2	2	2	2	2	*0*
	Fiber-Optic Ring Expansion in Toronto (km)		54	48			*102*	0	0	0	18	0	*18*						
	Fiber-Optic Ring Expansion in Scarborough (km)		64	72			*136*	0	0	0	2	1	*3*						
	New Wireless SCADA SD9 High-Site Deployment (# of Sites)	3	1				*4*	0	0	0	0	6	*6*			12			*12*
	Wireless SCADA GE Transit to GE SD9 Endpoint Radio Equipment Migration (# of Radios)		194	289			*483*	0	0	0	0	270	*270*			885			*885*

	2016 ACA Results (AMPCO-42b) [Old Methodology]					2017 ACA Results [AMPCO-48] [New Methodology]					% Change
Asset Class	Very Good	Good	Fair	Poor	Very Poor	HI1	HI2	HI3	HI4	HI5	Poor/Very Poor --> HI4/HI5
Over Head Gang Operated Switches	28.40%	70.40%	1.00%	0.20%	0.00%	88.13%	2.79%	7.84%	0.31%	0.93%	1.04%
SCADAMATE Switches	57.40%	41.80%	0.90%	0.00%	0.00%	96.87%	0.09%	2.32%	0.00%	0.71%	0.71%
Wood Pole	61.90%	19.60%	15.60%	1.40%	1.50%	63.91%	5.40%	19.53%	10.16%	1.00%	8.26%
4kV Oil Circuit Breaker (MS)	0.00%	7.50%	79.60%	12.90%	0.00%	19.25%	2.14%	65.78%	12.83%	0.00%	-0.07%
KSO Circuit Breakers (TS)	0.00%	18.00%	74.40%	7.70%	0.00%	25.00%	17.50%	27.50%	27.50%	2.50%	22.30%
SF6 Circuit Breakers (TS)	15.50%	65.00%	19.50%	0.00%	0.00%	81.25%	3.75%	11.25%	1.88%	1.88%	3.75%
Vacuum Circuit Breaker (MS & TS)	52.80%	42.20%	4.80%	0.20%	0.00%	86.53%	6.89%	1.95%	0.30%	4.34%	4.44%
Air Magnetic Circuit Breaker (MS & TS)	2.40%	16.90%	74.40%	6.20%	0.20%	26.08%	16.19%	44.42%	3.78%	9.53%	6.91%
Airblast Circuit Breaker (MS & TS)	0.60%	7.10%	88.00%	4.40%	0.00%	6.41%	3.85%	88.03%	0.43%	1.28%	-2.69%
Station Power Transformers	23.30%	49.60%	26.70%	0.40%	0.00%	34.30%	31.82%	25.21%	5.37%	3.31%	8.28%
Network Transformers	50.60%	42.20%	7.10%	0.10%	0.00%	73.22%	14.00%	9.11%	3.29%	0.38%	3.58%
Network Protectors	59.80%	12.50%	27.50%	0.10%	0.00%	64.26%	10.95%	18.88%	4.38%	1.54%	5.82%
Cable Chambers	24.60%	62.40%	10.10%	2.70%	0.20%	73.01%	10.46%	12.15%	3.58%	0.80%	1.48%
Submersible Transformers	57.90%	33.10%	8.60%	0.50%	0.00%	87.80%	6.61%	3.04%	1.93%	0.62%	2.05%
Air-Insulated Padmount Switches	40.20%	55.60%	4.30%	0.00%	0.00%	70.63%	3.50%	12.76%	5.24%	7.87%	13.11%
Vault Transformers	28.70%	42.00%	28.40%	1.00%	0.00%	57.54%	36.47%	3.80%	1.81%	0.38%	1.19%
Underground Vaults (combined)						77.28%	14.13%	5.47%	0.91%	2.20%	
ATS Vaults						100.00%	0.00%	0.00%	0.00%	0.00%	
CLD Vaults						100.00%	0.00%	0.00%	0.00%	0.00%	
CRD Vaults						90.00%	0.00%	10.00%	0.00%	0.00%	
Network Vaults	0.00%	66.60%	32.50%	0.90%	0.00%	59.08%	22.02%	11.56%	2.02%	5.32%	6.44%
Submersible Switch Vaults						95.83%	4.17%	0.00%	0.00%	0.00%	
URD Vaults						88.56%	9.97%	1.31%	0.16%	0.00%	
Padmount Transformers	13.90%	79.30%	6.80%	0.00%	0.00%	83.83%	9.91%	4.28%	1.71%	0.27%	1.98%
SF6-Insulated Padmount Switches						98.05%	0.00%	0.49%	0.00%	1.46%	
SF6 insulated Submersible Switches						89.14%	3.54%	1.77%	0.76%	4.80%	
Air Insulated Submersible Switches						86.98%	9.10%	3.11%	0.81%	0.00%	

Table 7: Asset Condition Assessment for Underground Transformers in 2017 and 2024 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total 2017	Total 2024
	2017	2024	2017	2024	2017	2024		
HI1 - New or Good Condition	4474	4153	6272	5986	1975	1528	**12721**	**11667**
HI2 – Minor Deterioration	603	296	534	280	1385	437	**2522**	**1013**
HI3 – Moderate Deterioration	246	555	232	501	143	1325	**621**	**2381**
HI4 – Material Deterioration	88	205	168	121	74	163	**330**	**489**
HI5 – End-of-Serviceable Life	16	218	42	360	12	136	**70**	**714**
Unavailable	493	493	1198	1198	299	299	**1990**	**1990**
Grand Total	**5920**	**5920**	**8446**	**8446**	**3888**	**3888**	**18254**	**18254**

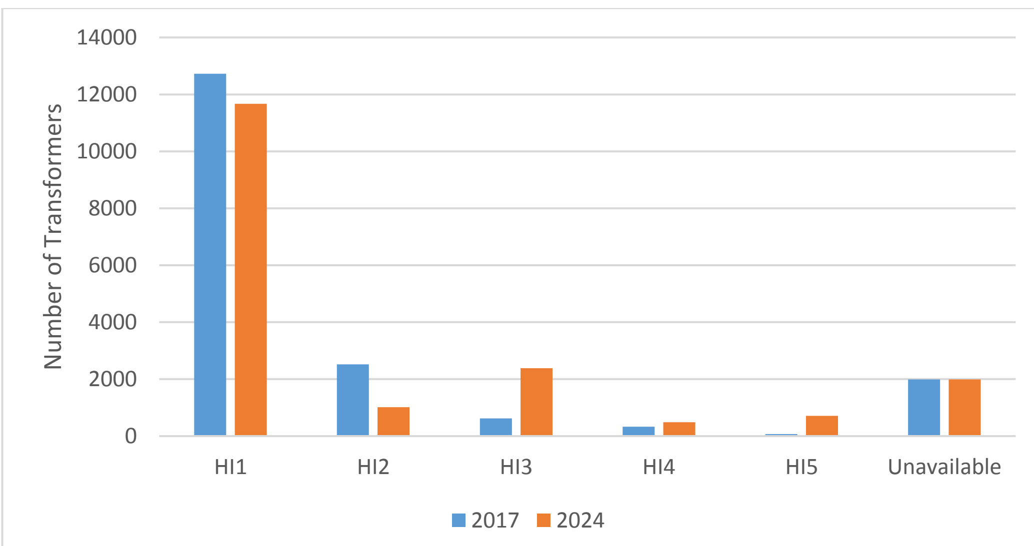

Figure 8: Underground Transformers ACA as of 2017 and in 2024 without Investment

A summary of the 10-year reliability of the underground transformers is shown in Figure 9, Figure 10 and Figure 11. As seen in Figure 9, there has been an overall reduction in the number of system outages (e.g. an average of 99 per year between 2007 and 2009, down to an average of 67 per year

Condition data for Air and SF_6 type underground padmounted switches are shown in Table 8. Data shows that 70 padmounted switches have at least material deterioration and should be considered for replacement as of 2017. The table also shows that without any capital renewal the number of switches with at least material deterioration is projected to approximately double by 2024 (141 switches) thus increasing the risk of failure due to deteriorated assets on the system.

Table 8: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type in 2017 and 2024 without Investment

Condition	UG Switch – Padmounted Air		UG Switch – Padmounted SF_6		Total 2017	Total 2024
	2017	2024	2017	2024		
HI1 - New or Good Condition	381	355	263	263	**644**	**618**
HI2 – Minor Deterioration	19	29	0	0	**19**	**29**
HI3 – Moderate Deterioration	68	20	2	0	**70**	**20**
HI4 – Material Deterioration	29	5	0	0	**29**	**5**
HI5 – End of Serviceable Life	41	136	6	8	**47**	**144**
Unavailable	40	33	256	256	**296**	**289**
Grand Total	**578**	**578**	**527**	**527**	**1105**	**1105**

In Toronto Hydro's underground distribution system in the Horseshoe area, 6 percent of the outages between 2007 and 2017 were caused by switch failure, they can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching. When load is transferred from one feeder to another, individual switches are closed or opened so power can be diverted from one feeder to another. These actions cannot occur when a padmounted switch fails, leading to a significant negative effect on system reliability by causing an outage or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figure 17, Figure 18 and Figure 19. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failure since 2012 as shown in Figure 17. However, the population of switches in service is aging and if Toronto Hydro does not maintain the current renewal pace, the utility expects that the current level of reliability performance will not be sustained and failure rates will increase.

and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require costly, routine CO_2 washing to remove accumulated contaminants.

E6.2.4 Expenditure Plan

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

	Actual			Bridge		Forecast				
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Underground System Renewal Horseshoe	115.5	80.7	83.1	70.0	71.4	93.0	88.7	90.3	93.1	95.2

E6.2.4.1 2015-2019 Variance Analysis

Over the 2015-2019 period, Toronto Hydro forecasts total spending of $420.7 million in the Underground System Renewal program, which is approximately $39 million lower than planned in the 2015-2019 Distribution System Plan. Nonetheless, Toronto Hydro is on pace to exceed the amount of cable and number of transformers installed related to the same plan.

Over the 2015-2017 period, Toronto Hydro spent $279.1 million and installed 720 kilometres of underground cable in duct, 1,555 transformers, and 213 underground switches, as shown in Table 10. Toronto Hydro plans to invest another $141.4 million in 2018-2019.

Table 10: 2015-2019 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge	
		2015	2016	2017	2018	2019
Cable	*km*	105	442	173	167	159
Transformers	*Units*	105	710	740	310	296
Switches	*Units*	47	79	87	43	41

During 2015-2017, Toronto Hydro invested at a higher pace than planned, installing an incremental 215 circuit-kilometres of primary cable and 611 transformers, and 16 fewer padmounted switches. The increase in the number of transformer units was due to an increasing need to address submersible transformers that were at risk of containing PCBs, had deteriorated in condition, and posed an unacceptable risk to the environment due to oil leaks. This increase was triggered in part by improvements Toronto Hydro made to its inspection forms and processes, resulting in a more accurate picture of the condition of submersible transformers and number of identified leaks. The higher pace of cable replacement was tied to this same issue, as Toronto Hydro worked to prioritize rebuild projects that addressed submersible transformers.

More broadly, variances in area rebuild programs such as this can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2020-2024 Forecasts

Toronto Hydro plans to spend $460.3 million in this Program over the 2020-2024 period. The 2020-2024 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience gained executing this type of work over the last three years. The estimated volumes for major underground asset replacements during the 2020-2024 period are shown in Table 11.

Table 11: 2020-2024 Estimated Volumes (Forecast) – Underground Circuit Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2020	2021	2022	2023	2024	Total
Cable	*km*	103	96	96	98	98	**491**
Transformers	*Units*	407	380	380	387	387	**1,941**
Switches	*Units*	49	45	45	46	46	**231**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds and spot replacements.

Four types of work are carried out through this Program. They include:

- **Area Rebuilds:** Rebuild projects are prioritized based on the historical failure of major assets (such as cable and transformer) on the feeder, the concentration of assets in deteriorated condition or at or beyond useful life, and potential reliability impact on customers supplied by the feeder. Rebuilding entire areas is intended to ensure proper coordination of work and efficient mobilization of crews as it is in the customers' interest to undergo only one outage

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 62:

Reference(s): **Exhibit 2B, Section E6.7, p. 9, Figure 4**

a) Please provide the values for the number of work requests for underground, overhead and station work and the totals for each year 2013 to 2018.

b) Please provide the number of work requests for the secondary network.

c) Please provide a breakdown of the number of underground assets replaced by asset type for each of the years 2013 to 2018.

d) Please provide a breakdown of the number of overhead assets replaced by asset type for each of the years 2013 to 2018.

e) Please provide a breakdown of the number of station assets replaced by asset type for each of the years 2013 to 2018

RESPONSE:

a) Please refer to Toronto Hydro's response to interrogatory 2B-SEC-64.

b) Please see Table 2 below for Secondary Networks Work Requests

Table 2: 2013 – 2018 Work Requests (Secondary Network)

Number of work requests	2013	2014	2015	2016	2017	2018
Secondary Network	59	118	186	176	253	306

c) Please see Table 3 below for major Underground Asset replaced.

Table 3: Major Underground Assets replaced

	2013	2014	2015	2016	2017	2018
Cable Chamber	14	26	28	21	27	27
Network Protector	5	14	13	27	16	5
Switch	72	52	112	85	109	45
Underground Transformer	260	382	356	601	530	454
Transformer Pad	8	13	11	26	53	18
Vault Asset	46	158	157	210	426	368

d) Please see Table 4 below for major Overhead Assets replaced.

Table 4: Major Overhead Assets replaced

	2013	2014	2015	2016	2017	2018
Overhead Transformer	181	188	215	107	109	45
Switch	45	63	62	40	56	33
Pole	219	347	336	192	225	125

e) Please see Table 5 below for major Station Assets replaced.

Table 5: Major Station Assets replaced

	2013	2014	2015	2016	2017	2018
Station Battery	4	4	0	24	14	2
Station Power Transformer	0	1	0	2	6	3
Switches	2	3	0	6	10	20
Station Air Compressor	0	0	1	0	0	0
Station Switchgear	0	0	0	0	1	1
Circuit Breaker	0	0	0	0	3	0

address declining reliability seen in 2013 and 2014) which continued into 2016. These investments have contributed to a steady improvement in reliability between 2015 and 2017.

Table 7: 2015 – 2019 Overhead Asset Replacement (Units)

Asset Class	Actual			Bridge		Total 2015-2019
	2015	2016	2017	2018	2019	
Poles	3656	2692	1513	1100	550	**9,023**
Transformers	940	769	441	575	290	**3,174**
OH Switches	192	167	120	55	35	**457**
Conductors* (km)	155	179	123	70	63	**527**

*Primary cables only

Overhead System Renewal spending was ramped down in 2017 through 2019 to accommodate the progression of certain other priority programs (e.g. Box Construction Conversion). Another factor contributing to cost variances is project scope adjustment as projects progressed from high level estimates to detailed designs. For example, designers may identify additional or fewer assets that should be included, scope changes due to interference with other utilities' works, or additional restoration costs.

E6.5.4.2 2020-2024 Forecasts

Toronto Hydro forecasts spending $265.7 million on the Overhead System Renewal program over the 2020-2024 period. This includes the cost of replacing end of life assets, converting the 4.16 kV and 13.8 kV distribution system to standard 27.6 kV lines, and renewing Overhead Street lighting assets deemed to be distribution assets.[3] The 2020-2024 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the 2020-2024 period, as shown in Table 8.

Table 8: 2020-2024 Volumes (Forecast): Overhead System Renewal

Asset Class	2020	2021	2022	2023	2024	Total
Poles	2,230	2,230	2,220	2,400	2,450	**11,530**
Transformers	1300	1300	1300	1400	1400	**6,700**
OH Switches	130	130	130	160	160	**710**
Conductors* (km)	70	70	70	70	70	**350**

[3] See EB-2009-0180 et al Decision and Order dated February 11, 2010.

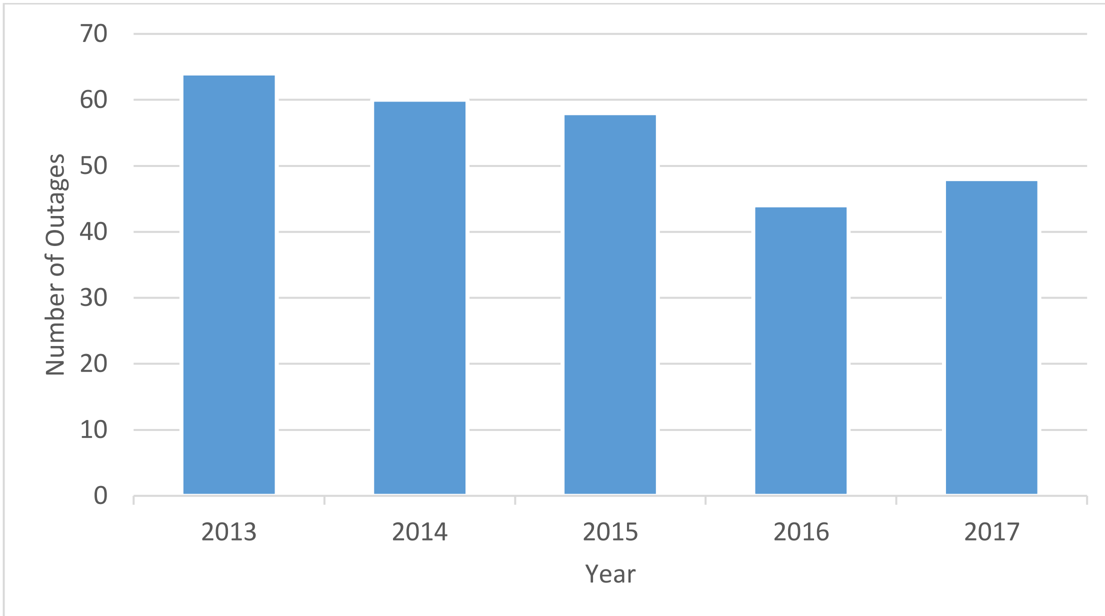

Figure 4: Forced Outages for Pole-top Transformers

Although on-going renewal work has contributed to the overall decline in reactive work requests since 2013, more than 80 requests were still made in 2017 (compared to over 60 in 2016). The vast majority of requests relate to transformer failures (approximately 40 to 70 failures per year), contributing to over 10,400 customers interrupted and 6,100 customer hours interrupted over the same period (see Figure 5).

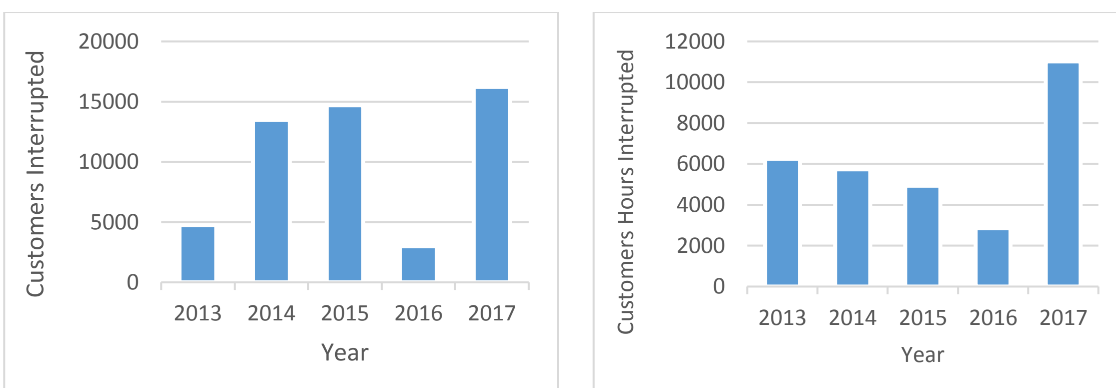

Figure 5: CI (Left) & CHI (right) for Pole-top Transformers

As part of Toronto Hydro's Quality Program, the organization investigated 145 failed overhead transformers between 2013 and 2017 to identify root causes of failure. The investigations found that

D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's main asset management process is known as the Distribution System AM Process, referenced throughout the DSP as the "AM Process". The utility's processes for non-system (i.e. general plant) assets are fundamentally aligned with the AM Process, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Distribution System AM Process;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the sections that follow:

- **Section D1** provides an overview of the elements that constitute the AM Process, including the relationship between corporate goals and asset management objectives, and describes Toronto Hydro's roadmap for continuous improvement in distribution system asset management, including enhancements and innovations that have been completed or commenced, with an emphasis on innovations in the period since the OEB's December 2015 decision on Toronto Hydro's 2015-2019 Custom IR application.
- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 67:

Reference(s): **Exhibit 2B, Section D3, pp. 4, 11, 13-14, 22-24, 30, 47**

a) Regarding the planned maintenance activities (Exhibit 2B / Section D3 / p. 4), please explain how the cycles (number of years) were established.

b) Regarding the repair of failed or defective equipment (Exhibit 2B / Section D3 / p. 11), please explain how these costs are treated (capital or OM&A) and provide the total cost of these types of repairs over the 2015-2019 period.

c) With respect to overhead switches (Exhibit 2B / Section D3 / p. 13), please explain why Toronto Hydro does not have a dedicated proactive renewal strategy for this class of asset.

d) With respect to overhead conductors (Exhibit 2B / Section D3 / p. 14), please explain why Toronto Hydro does not have a dedicated proactive renewal strategy for this class of asset.

e) Please explain how asset condition assessment, predictive failure modelling, historical reliability analysis and economic risk-based analysis interact in terms of determining how to direct capital expenditures.

f) Please advise whether a scope of work document is produced for every project or only for major projects. Please provide a sample scope of work document (Exhibit 2B / Section D3 / p. 47).

RESPONSE:

a) As noted in Exhibit 2B, Section D3, pages 2-3, the foundation of Toronto Hydro's maintenance plans, including the specific maintenance activities and their associated cycles are Reliability Centered Maintenance ("RCM") analyses. The analyses answer a series of related questions with respect to assets and their components. These questions focus on (i) component functions, (ii) functional failures, (iii) failure modes, (iv) failure effects, (v) failure consequences, and (vi) maintenance tasks (and their cycles) that should be undertaken to predict or prevent failures. The answers to one question influence the answers to subsequent questions.

With respect to question (vi), the determination for each maintenance task is made by considering responses to previous questions (i.e. i – v) and factors such as mean time to failure, potential to functional failure (often referred to as p-to-f) intervals, and the cost of maintenance relative to replacement at the time of failure. Those determinations also consider other factors such as minimimum inspection requirements pursuant to the Distribution System Code. The outputs from the RCM analyses form the set of recommended maintenance tasks, and the cycles that are contained in Table 1 of Exhibit 2B, Section D3.

Please note that not all maintenance activities and cycles in Table 1 are set using RCM analyses. Below is a list of notable exceptions together with a brief description of how associated cycles were established:

- **Tree Trimming**: As described in Exhibit 4A, Tab 2, Schedule 1, page 29, feeders are trimmed on a variable cycle of two to five years based on assessments of tree pruning needs that consider criteria such as feeder reliability history, number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned.

- **Insulator Washing**: Only locations at a high risk of accumulating contamination (predominantly from road de-icing materials that become airborne and attach to insulators) are washed twice a year as described in Exhibit 4A, Tab 2, Schedule 1, beginning on page 22. These high risk locations are fewer than 5% of Toronto Hydro's wood pole locations and they are washed once prior to the use of de-icing salts and brines on roadways (i.e. in Fall) and once after (i.e. in the Spring).

- **Contact Voltage**: As described in Exhibit 4A, Tab 2, Schedule 2, page 32, contact voltage causes include the freeze/thaw cycle and as a result, scanning is planned on an annual cycle to monitor conditions during and following winter months.

b) Costs associated with repair and refurbishment of failed or defective equipment would be treated as capital with a few exceptions (e.g. assets do not go into service, repairs were unsuccessful). For further context, failed or defective equipment is taken out of service, salvaged (if repair or refurbishment is feasible), and returned to the manufacturer (or third party) to be repaired or refurbished. Repaired or refurbished equipment is then used as part of capital projects.

Toronto Hydro estimates direct repairs and refurbishments (e.g. transformers) will cost approximately $1 million over the 2015-2019 period. Savings associated with repairs and refurbishments are estimated to exceed $5 million over the same period.

c) Asset classes or types for which Toronto Hydro does not have a "dedicated proactive renewal strategy" are ones that are (along with their associated risks) capable of being managed as part of a broader strategy. For overhead switches, Toronto Hydro is managing and renewing them through broader renewal efforts on the entire overhead system (e.g. area rebuilds) or through reactive programs. On their own, overhead switches do not drive or merit a "dedicated" approach at this time.

d) See response to part (c). Simlar to overhead switches, conductors do not drive or merit a "dedicated" approach at this time.

e) Toronto Hydro utilizes tools such as asset condition assessment ("ACA"), predictive failure modelling, historical reliability analysis, and economic risk-based analysis results when determining how to direct capital expenditures at all stages of the Asset Management ("AM") Process illustrated in Figure 2 of Exhibit 2B, Section D1. The specific interaction varies depending on the component of the AM Process being engaged and the specific type of capital (program or project) being considered.

For example, during the Investment Planning and Portfolio Reporting ("IPPR") process, a planner responsible for Stations Renewal will utilize all of the aforementioned tools but may choose to place incremental weight on predictive failure modelling, while a planner responsible for Overhead System Renewal may choose to place incremental weight on historical reliability analysis or economic risk-based analysis when developing portfolio and program capital expenditure proposals. (Contributions to reliability measures are greater from the overhead system than they are from stations.) During the IPPR process, senior management will similarly utilize the same tools to assess the expenditure levels proposed for each program and the overall mix of capital proposed across all programs.

Another example occurs at the Scope and Project Development component of the AM Process. To identify specific needs, assess options, and ultimately develop scopes of work, planners will utilize ACA and economic risk-based analysis to prioritize individual assets for intervention (e.g. replacement), and identify clusters of poor condition or high risk assets that can be grouped into a project within a given program. Other tools such as historical reliability analysis and predictive failure modelling may be used to provide results at a feeder or group level. In these situations, Toronto Hydro uses the tools to make specific decisions about where capital should be directed within particular parts of the distribution system.

A third example comes from the Program Management & Execution component of the AM Process. At this stage, Toronto Hydro utilizes the referenced tools to prioritize projects for execution and to create the following year's work program. Projects addressing greater numbers of assets in HI4 or HI5 (asset condition assessment) categories or feeders with particularly poor historical reliability may be prioritized over other projects. For more information about project prioritization, please see Toronto Hydro's response to interrogatory 2B-SEC-36 (a). At this stage, the tools are utilized to direct capital expenditures within a specific year or defer available projects (and their associated capital) to later years.

Please note that although this response has focused on the four tools referenced in the question, Toronto Hydro applies a wide variety of tools and indicators throughout the AM Process to make effective capital decisions. An example of this may be found in Exhibit 2B, Section E6.6, at page 57, in relation to the Stations Renewal program. The tools and indicators listed (and considered) when planning that program are reproduced below for ease of reference:

1) Age
2) Dissolved gas-in-oil analysis
3) Condition Assessment
4) Loading
5) Load
6) PCB concentration in oil
7) Resiliency of the surrounding distribution system to withstand transformer failures
8) Any other electrical tests (such as power factor and insulation resistance tests)
9) Voltage conversion planned

f) A scope of work document is produced for every project. A sample scope of work document is provided in Appendix A.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These asset can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained with a constrained expenditure plan.

This section outlines Toronto Hydro's lifecycle risk management methods and practices for its distribution assets, detailing the utility's risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro's risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure is an important consideration in determining whether asset intervention is necessary. This section focuses upon two key forms of analytics that are utilized to enable Probability of Failure evaluation: (i) Asset Condition Assessment ("ACA"); and (ii) predictive failure modelling.

1. Asset Condition Assessment (ACA)

As explained in Section D1 and in Appendix C to Section D, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a health index ("HI") score to support project planning. The ACA allows Toronto Hydro to use data collected data through inspections to produce a numerical representation of an asset's condition, taking into account key factors that affect its operation, degradation, and lifecycle. Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

As part of the efforts to continually improve its asset management and decision-making framework, Toronto Hydro worked with EA Technology to develop new asset health models based upon the Common Network Asset Indices Methodology ("CNAIM"). CNAIM is the approach used by distribution network operators in the United Kingdom to report asset health as part of their regulatory reporting requirement. Toronto Hydro has used the outputs from this CNAIM-based model to support an advanced condition-based approach for planning and evaluating strategic capital investments. Toronto Hydro has provided additional details on the new ACA methodology in Appendix C to Section D of the DSP.

The approach used to develop the HI for each asset is illustrated in Figure 3.

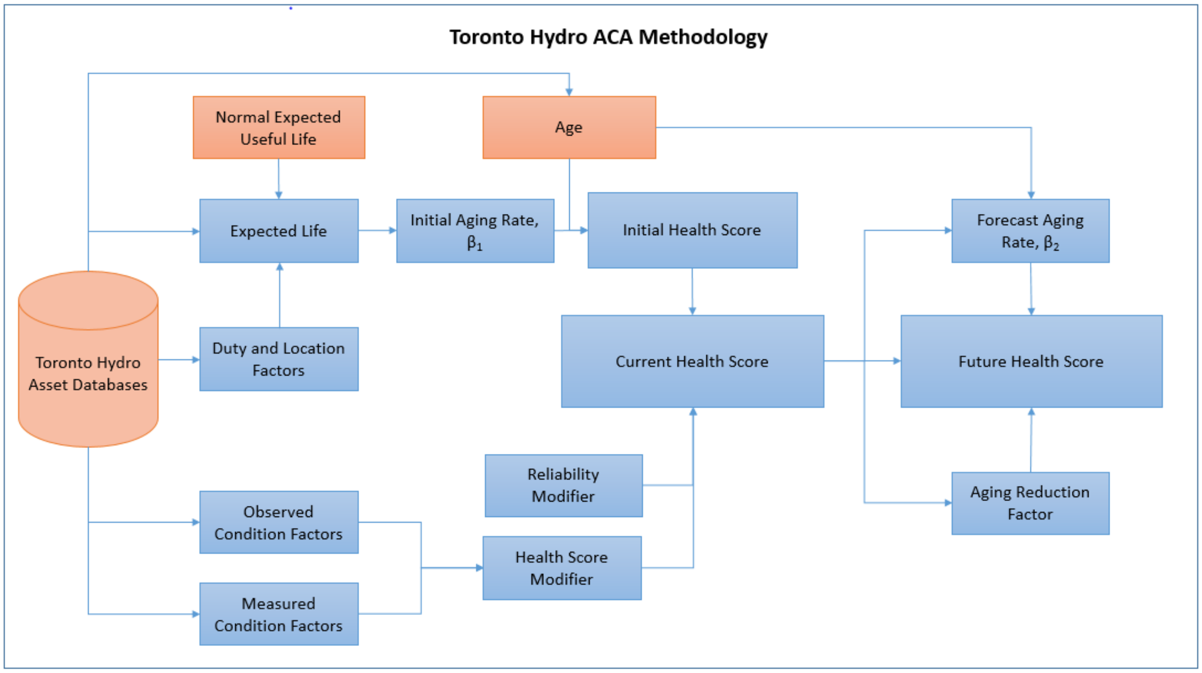

Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results for a particular asset class are grouped into five HI bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset HI demographics during the scope development phase of IPPR, as outlined in Section D1. It enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5	≥ 8	≤ 10	End of serviceable life; intervention required

Examples of asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA Program

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA program highlights trends in the condition of asset classes. These trends can highlight issues that are specific to particular asset classes or subtypes such as manufacturing defects, or design practices. For system planners, these insights along with the health band of an asset provide an indication of the probability of failure for an asset. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and future health index results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2020-2024 DSP, Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5"). For more information, refer to Section E2.

For more information on Toronto Hydro's ACA approach, refer to Appendix C to Section D.

2. Predictive Failure Modelling

Predictive failure modelling represents the other essential component of the Probability of Failure analysis. It involves the derivation of hazard rate functions for each asset class – also referred to as the assets' probability of failure. In this case, an asset's age is used as an input into the hazard rate calculation in order to produce the conditional probability of an asset failing based on the remaining population that has survived up until that time. The results from these failure curves provide insights into the expected failure rates of assets, which is critical information for determining the investments required to manage assets over the medium term.

Toronto Hydro's hazard rate distribution functions were each calibrated to a useful life value. Toronto Hydro's useful life values are also used separately as part of the Assets Past Useful Life ("APUL") calculation, in order to assess the demographics of assets, especially those approaching or past their useful life. Toronto Hydro utilizes this information to ascertain the upcoming "asset walls" and investment requirements that will emerge over a long-term period, and better equip its planners to make informed investment decisions and develop effective plans based on the needs of the system.

The aggregate information extracted from predictive failure modelling combined with the APUL calculation can be used as an input in determining the levels of expenditures required for managing each asset type. The predictive failure modelling procedure is also used as part of the economic risk-based analysis and reliability projection procedures, which are further discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The last component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data from the Interruption Tracking Information System ("ITIS"), in order to identify assets with a high frequency of failure.

ITIS is used to store historical outage information which Toronto Hydro uses as a key tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro is able to identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages within ITIS:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;

- Tree Contacts; and
- Unknown.

From a Probability of Failure perspective, the data contained within ITIS can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. As an example, ITIS data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability (explained in Section D3.2.1.1) as well as the consequences and impacts of failure, which go into to the specific failure modes and effects associated with those failure modes. These consequences are generally broken down into key categories that generally align with Toronto Hydro's outcomes framework (i.e. customer service, reliability, environment, safety, and financial impacts).

1. Customer and Reliability

Derivation of the customer or reliability impacts is undertaken through a number of tools and approaches, including:

- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

Table 9: Summary information related to Customer and Reliability Tools and Approaches

Tool or Approach	Summary
Customer engagement and consultation activities	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers and provide necessary details related to capital and maintenance plans, including the following: a) Town hall meetings in specific districts or parts of the city to communicate investment plans or proposed projects and execution strategies; b) Ward or neighbourhood outreach activities where city councillors are provided necessary information from Toronto Hydro in regards to major investments and issues being mitigated within their respective communities; and c) A customer-focused power quality program in which Toronto Hydro monitors and investigates power quality issues for customers.
Key account customer program	Toronto Hydro manages a key account customer program for large commercial and industrial customers to address specific concerns and issues. Additionally, any specific customer concerns or complaints captured through Toronto Hydro's call centre are directed to engineers, asset planners, and managers within the Engineering (and Asset Management) group to investigate and determine whether projects already exist to address the concerns or if new projects (and additional actions) are required.
Reliability analysis identifying long-duration impacts	As explained above in Section D3.2.1.1, Toronto Hydro utilizes its ITIS system to gather historical reliability data across the distribution system for the purposes of performing reliability-driven analyses. For example, ITIS is relied upon for insight into the number of customers affected by outage events in the system and the duration of each event. From a consequences of failure perspective, this information is used to identify typical outage duration impacts within the system, and to plan and prioritize projects as illustrated in programs such as Area Conversions (Exhibit 2B, Section E6.1) and Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2). Given Toronto Hydro's reliance on the functionality that ITIS provides, Toronto Hydro is investing in this functionality as part of its upgrade of the existing Outage Management System with a new Network Management System ("NMS"). Toronto Hydro expects that this investment will provide more robust data and enable greater insights. These upgrades are expected to be completed in the period 2018-2020.

Tool or Approach	Summary
Application of customer interruption costs	Toronto Hydro utilizes customer interruption costs ("CICs") which represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: the Event cost and the Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage whereas the Duration cost represents the costs incurred as the length of the outage increases. Toronto Hydro currently adopts $30 per kVA (peak load) as the Event cost to represent the CIC value due to the initial period of the outage, and $15 per kVA (peak load) per hour to represent the CIC value due to the increasing duration of the outage. Toronto Hydro continues to enhance these values by directly surveying customers to understand their valuation of interruption costs. These CICs are used as input within the economic risk-based analysis as described in Section D3.2.1.3. As part of this analysis, the CICs are paired with customer impact information, including the associated customer load that will experience an interruption should the evaluated asset fail. This customer impact information includes the identification of the upstream protective device that will contain the fault, as well as the customer loading impacts, which are derived from the peak load of the downstream transformers. Collectively, this information is used to quantify the full customer impact of failure for each evaluated asset within the system.

2. Environment

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment as well as safety incidents to its employees, customers and the public. In the case of equipment failure, environmental impact, and potential non-compliance or breach of regulatory obligations may result. Toronto Hydro's major environmental concerns include: (i) oil leaks of all types; (ii) reducing greenhouse gas emissions; and (iii) the use of substances like asbestos, lead, and PCBs in its equipment.

Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and proposed for replacement with standardized and less harmful equipment.

3. Safety

Mitigating safety risks to Toronto Hydro employees and its customers is the highest priority objective of Toronto Hydro's AM process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Toronto Hydro continues to strive for zero public and employee safety incidents each year.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometime entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations; and
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations.

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4A, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4A, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with a new standardized equipment. This was the case in the 2015-2019 CIR Programs of SCADA-Mate R1 Switch Renewal, Handwell Upgrades, and Polymer SMD-20 Switch Renewal. Within this application the Contact Voltage Scanning Segment under Preventative and Predictive Underground Line Maintenance (Exhibit 4A, Tab 2, Schedule 2) addresses the scanning of the distribution system for contact voltage to reduce risk of public exposure to contact voltage from energized surfaces and structures.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Through its renewal programs and consistent with the Ontario Long-Term Energy Plan, Toronto Hydro is investing in asset designs that are more resilient to changes in weather and climate such as the use of submersible network protectors to tolerate flooding. Additionally, implementing demand response programs reduces the strain on Toronto Hydro distribution assets and as such reduces failure risk.

Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273 and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers; and
- Ensuring compliance with *Ontario Regulation* 22/4 and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Asset failure can cause outages disrupting the normal operations of businesses (leading to monetary losses as represented by CICs discussed in Table 9 above), damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and resulting litigation. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions.

The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Economic Risk-Based Analysis

Toronto Hydro’s economic risk-based analysis methodology supports the utility’s engineering assessment of system intervention and design alternatives. This methodology calculates an economic end-of-life for each asset by balancing the increasing risk of asset failure against the necessary investment costs that must be incurred in order to mitigate these risks. Toronto Hydro leverages the Feeder Investment Model (“FIM”) tool to produce these calculations. Key input data includes results from Predictive Failure Modelling described in Section D3.2.1.1, and quantified reliability impacts to customers (i.e. customer interruption costs).

The FIM also stores the financial costs to the utility for replacing the evaluated assets should they fail within the system, along with the typical failure modes associated with the asset in question. From these parameters, an annualized risk cost and an annualized capital cost can be derived for the new asset to be installed, and a life-cycle cost established based upon a sum total of these two components. The lowest life-cycle cost of the new asset – or the Equivalent Annual Cost (“EAC”) – may be compared to the risk cost of the existing asset to identify the economic end-of-life for the existing asset. This is further illustrated in Figure 2.

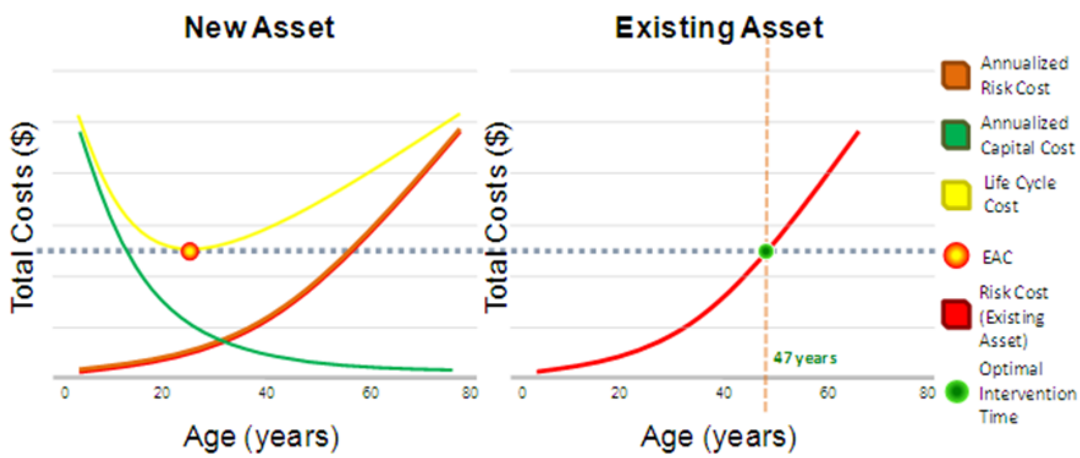

Figure 4: Typical Example of Establishing the Optimal Intervention Time for an Existing Asset

Figure 4 illustrates that past the point of the lowest life-cycle cost (i.e. EAC), it becomes more expensive to continue to operate the existing asset, when taking into consideration both financial impacts to the utility as well as socioeconomic impacts (including those relating to customer and reliability, safety, and environmental impacts). The economic end-of-life results from this analysis are mainly used to evaluate the net benefits of asset intervention alternatives.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond useful life, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces program scenarios to project the reliability impact of the investment programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate reliability impact of the proposed capital expenditure plan. It should be noted that this projection does not consider major event days, nor the lasting impacts that major weather events can have on asset performance in future years.

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders at risk of experiencing seven or more sustained interruptions ("FESI-7") each year (or over a 12-month rolling period). Once the feeder and the root cause of its failures have been identified, mitigation work on these feeders is conducted so that the risk of additional interruptions to customers can be mitigated. In addition to the FESI-7 metric, Toronto Hydro has introduced a FESI-6 metric that identifies at-risk feeders serving Large Commercial & Industrial class customers within the distribution system. Additional details related to these measures, which are in place to improve reliability and meet the needs of customers, may be found in Exhibit 2B, Section C.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Section C.

For more detail on the work proposed as part of WPF investments, refer to Exhibit 2B, Section E6.7.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset integrity risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Defective Equipment Tracking and Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework, which is referred to as Defective Equipment Tracking System ("DETS"), is useful for assessing risk trends related to both particular asset classes and the system overall.

The DETS framework utilizes information about defective equipment to assign a score, which reflects the following criteria:

- **Impact**: number of customers impacted by the defective equipment incident;
- **Contingency**: what is the criticality of the equipment and are there any contingency options; and
- **Restoration**: the estimated restoration time to the customers.

Each criteria is assigned individual scores and when combined for a particular piece of equipment, could reach a maximum of 1,000. Once scored, a piece of defective equipment is then prioritized for corrective work as part of Toronto Hydro deficiency prioritization process that is used for all deficiencies identified during the course of utility operations (and not just defective equipment deficiencies). That process has three categories of priorities:

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

A P1 is assigned to defective equipment that has a DETS score greater than 100 and a P2 is assigned to defective equipment that has a score less than 100. Analysis of the DETS scores and the volumes of priority deficiencies provides Toronto Hydro with another layer of risk modelling and inputs for risk management.

For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital (Exhibit 2B, Section E6.7), Corrective Maintenance (Exhibit 4A, Tab 2, Schedule 4), and Emergency Response (Exhibit 4A, Tab 2, Schedule 5) programs.

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short-, medium- and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories of System Renewal or System Service.

D3.2.2.1 System Renewal Investments

As part of Toronto Hydro's risk mitigation efforts, System Renewal investments form a significant portion of the utility's capital investments. In addition to investments that help reduce the probability of failure based on age and condition, this investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, renewal programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. The System Renewal category also includes more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program (Exhibit 2B, Section 6.7).

D3.2.2.2 System Service Investments (Enhancements)

In addition to mitigating risk through the renewal of assets, Toronto Hydro invests in programs that allow for other cost-effective forms of risk mitigation. For example, in the network system, Toronto Hydro is investing in monitoring capability for vaults through the Network Monitoring and Control program. This program allows Toronto Hydro to proactively identify key issues affecting the network system such as vault flooding in order to intervene prior to potentially catastrophic asset failure. Installation of network monitoring and control systems or SCADA-Mate switches (on overhead lines) allows Toronto Hydro to address reliability related risks (in particular, outage duration risks), in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

D3.2.2.3 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4A, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.4 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada. Investments are also required to ensure that capacity is available for connecting customers, which is further discussed in Section D3.3.

E8.8 Program Support

E8.8.1 Summary

Program Description

Toronto Hydro's Distribution System Plan (DSP) has been developed through a series of asset management processes, tools, systems and resources, as identified within Section D (Asset Management Process). Key outputs of the Asset Management Process include both long-term capital programs and discrete capital projects contained within those programs. The proposed Program Support expenditures will allow for continued refinement and improvements to the development of capital projects within the five-year period along with future development of capital programs from 2020 and beyond, through the execution of two key support studies: a climate adaptation study and a customer interruption cost (CIC) study. Table A provides a summary of this program's benefits.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	▪ CIC study is expected to further enhance the Feeder Investment Model (FIM) with localized outage costs ▪ System improvements based on the studies will facilitate the reduction of customer impacts due to extreme weather events and climate change
Reliability	▪ Proposed studies will support efforts towards reduction in the frequency and duration of adverse-weather related outages ▪ The development of localized customer interruption costs would further enhance Toronto Hydro's capability to manage system reliability in a

	customer-focused manner
Safety	▪ Proactively targeting areas vulnerable to extreme weather and climate change impacts is expected to reduce crews' exposure to work on the system during severe weather events
Efficiency	▪ Enhancements to localized outage costs are expected to further enhance Toronto Hydro's business case evaluation (BCE) process, facilitating an enhanced economic evaluation of capital investments. ▪ Storm hardening improvements to the distribution system will help mitigate the risks associated with extreme weather events, creating opportunities for cost reductions of weather-related service restoration.

Program Drivers

The trigger driver for this program is summarized in the following table.

TABLE B: PROGRAM DRIVER

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	▪ Plans based on the climate adaptation study are planned to be executed in both Overhead and Underground Circuit Renewal Programs ▪ Update localized outage costs into the Feeder Investment Model

Preferred Alternative

In the absence of the proposed studies, adaptation to climate change within Toronto Hydro's distribution system can be derived solely from historical information and trends in weather-related events. Similarly, Toronto Hydro would continue to use existing customer interruption cost (CIC) inputs as part of their Feeder Investment Model (FIM) and business case evaluation (BCE) process. This option is not preferred as it does not address the expected impacts of climate change and would not allow for the continuous improvement of the FIM approach.

Timing and Pacing

Both studies comprising this program are planned to be conducted in the first two years of the DSP period. After the completion of the climate adaptation study, Toronto Hydro plans to review the plans completed through the FIM, as well as compare the climate change adaptation study results to the existing programs being executed, to benefit from any cross-program synergies or to build on existing programs that may already be investing in system resiliency. The CIC study is planned for completion in 2015 because the localized outage costs calculated would have to be tested and gradually incorporated into the FIM to further enhance the model in preparation of prioritization of projects in the later years of the DSP period. Toronto Hydro proposes to spend $1.7 million for this program as shown in Table C.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	1.2	0.5	0	0	0

E8.8.2 Program Description

The objective of Program Support program is to enhance Toronto Hydro's long-term and short-term asset management planning processes, and ultimately enhance capital program and capital project development through the execution of the key planning studies. These studies include a climate adaptation study and a customer interruption cost (CIC) study. The climate adaptation study would permit Toronto Hydro to enhance its standards and design practices with storm-hardening capabilities, while also identifying specific areas within the distribution system that face an elevated amount of weather-related risks. The CIC study is expected to enhance a key input that is used as part of Toronto Hydro's Feeder Investment Model (FIM) decision-support system, such that the overall business case evaluation (BCE) process will be further improved.

E8.8.2.1 Climate Adaptation Study

Toronto Hydro plans to conduct climate adaptation study in 2015 and 2016 to assist with engineering analysis, informed decision-making and standards for overhead and underground capital programs. The study will focus specifically on identifying areas of the distribution system that are vulnerable to extreme weather and climate change. Figure 1 shows an example of reconfiguring the distribution system to move it outside of a flood plain, which is an example of the type of work that could be carried out as result of climate adaptation study. As recommendations from the climate study become available, pilot projects will be conducted as part of the studies to test the recommendations. The purposes of including the pilot projects as part of the studies is to finalize the climate adaptation solutions before programs are carried out at a system level.

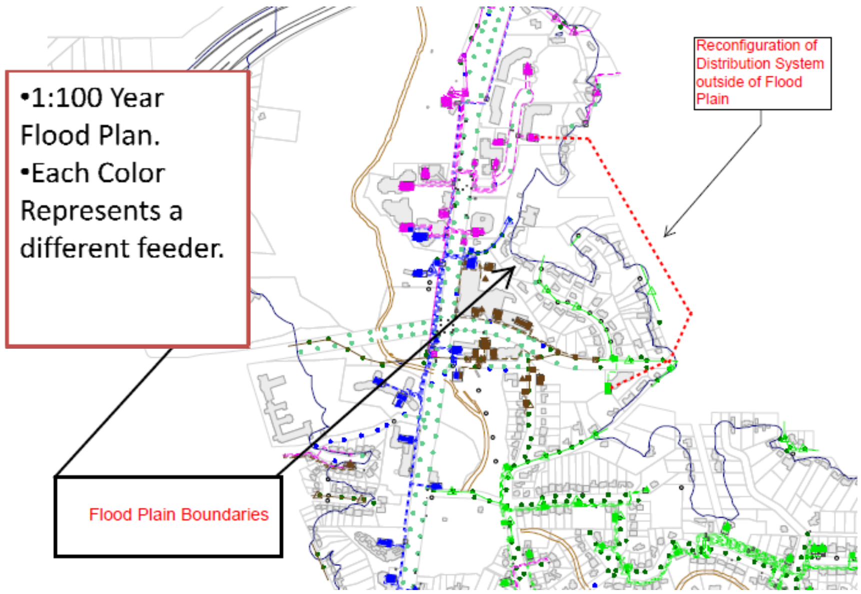

FIGURE 1: RECONFIGURING DISTRIBUTION SYSTEM OUTSIDE OF FLOOD PLAINS

E8.8.2.2 Customer Interruption Costs (CIC) Study

The proposed Customer Interruption Costs (CIC) study is a survey-based interruption cost study to estimate outage costs specific to the City of Toronto context. This study would survey various customer classes, Toronto Community Councils, and Business Improvement Areas (BIAs). Surveying across different customer demographics ensures that Toronto Hydro's diverse customer base is captured in this study. In addition, the proposed study would also ask each survey participant about their expectations (i.e. the frequency and duration of outages that customers consider acceptable) and perceptions (i.e. how satisfied customers are with the level of reliability they currently experience) of service reliability.

The selected vendor for this study would recommend outage scenarios and their proposed cost estimation methodology based on the diversity of survey participants. The different outage scenarios would include a combination of seasonal (summer/winter), weekly (weekend/weekdays), and daily (morning/afternoon/night). As shown in Figure 1, based on historical data, there is no single hour that accounts for more than 7% of outages or less than 2% of outages. Accordingly, the study must be designed to capture information across all time periods. Finally, each set of these scenarios will need to include durations of 5 minutes, 1 hour, 4 hours, 8 hours and 24 hours[1].

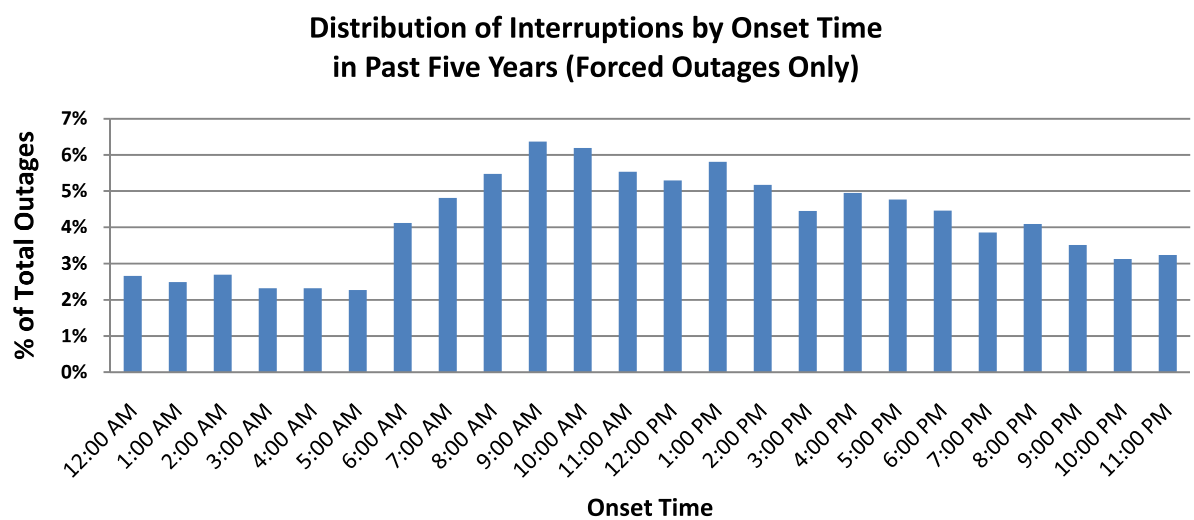

FIGURE 2: DISTRIBUTION OF INTERRUPTIONS BY ONSET TIME IN PAST FIVE YEARS

The different cost estimation methodologies are willingness-to-pay (WTP), willingness-to-accept (WTA), and direct-worth[2]. WTP cost estimations involve measuring the amount that customers would be willing to pay to avoid experiencing a service interruption; WTA involves measuring the level of compensation that customers would require to avoid a service interruption. Both of these approaches contribute to understanding how much customers would pay to avoid service interruptions. As costs for residential customers are mostly an inconvenience or hassle, they are often intangible and difficult to estimate using a direct-worth method. The combination of WTP and WTA approaches is a rigorous way of determining these implied costs. The direct-worth (DW) method involves asking customers to estimate the direct costs they would experience during a service interruption. These include outage related costs (e.g. labour and material costs incurred during an outage), lost production, cost to operate backup generation equipment,

[1] M.J. Sullivan and D.M. Keane, *Outage Cost Estimation Guidebook*, (Electric Project Research Institute Research Project 2878-04 Final Report) (San Francisco: Freeman, Sullivan and Company, 1995).
[2] Leona Lawton et al., *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, (Berkley: Population Research Systems, LLC and Lawrence Berkeley National Laboratory, 2003), online: Consortium for Electric Reliability Technology Solutions <http://certs.lbl.gov/pdf/54365.pdf>.

material costs to restart the production processes, etc. The DW approach is recommended for non-residential customers, i.e. small, medium, and large commercial and industrial (C&I) users.

This proposed study would survey customers across the Toronto Hydro service territory to determine system-wide values along with an analysis showing the confidence level of the values. Once these outage costs are calculated, they will be used in the FIM described in Section D3.

The anticipated benefits of this program are summarized in Table 1.

TABLE 1: SUMMARY OF PROGRAM BENEFITS

Customer Value	▪ CIC study is expected to further enhance the FIM with localized outage costs ▪ System improvements based on the studies would help reduce customer impacts due to extreme weather events and climate change
Reliability	▪ The studies would help achieve a reduction in the frequency and duration of adverse-weather related outages ▪ The development of localized customer interruption costs would further enhance Toronto Hydro's capability to manage system reliability in a customer-focused manner
Safety	▪ Proactively targeting areas vulnerable to extreme weather and climate change impacts would help reduce crews' exposure to work on the system during these events
Efficiency	▪ Enhancements to localized outage costs would allow Toronto Hydro to further enhance its business case evaluation (BCE) process, facilitating enhancements to the economic evaluation of capital investments. ▪ Storm hardening improvements to the distribution system would help mitigate the risks associated with extreme weather events, facilitating reductions in weather-related reactive work.

E8.8.3 Why the Program is Needed

The purpose of the two studies in this program is to assist Toronto Hydro in preparing for climate change and mitigate its impacts and to enhance the FIM by reflecting the localized interruption costs for Toronto Hydro's customers. The climate adaptation study would include detailed engineering analysis and development of climate adaptation plans as well as pilot project testing based on recommendations from the study's findings. Localized customer interruption costs would help Toronto Hydro enhance the FIM, which is used to prioritize future projects.

E8.8.3.1 Program Drivers

As shown in Table 2, the trigger driver for this program is System Maintenance and Capital Investment Support. This driver classifies the program in the General Plant category. These two key support studies would allow for the continued refinement and improvements of the development of the capital projects within the five-year period along with future development of capital programs beyond 2020.

TABLE 2: PROGRAM DRIVER

Trigger Driver	Reasoning
System Maintenance and Capital Investment Support	▪ Plans based on the climate adaptation study ware planned to be executed in both Overhead and Underground Circuit Renewal Programs ▪ Update localized outage costs into the Feeder Investment Model

(i) Climate Adaptation

On July 8, 2013, and December 22, 2013, (shown in Figure 3), the City of Toronto was hit with two different types of extreme weather that adversely affected Toronto Hydro's distribution system.

FIGURE 3: FALLING BRANCH ON STREET ENTANGLED WITH CONDUCTOR[3]

[3] "Photos: Toronto coated in ice following destructive winter storm", *Windsor Star* (22 December 2013) online: Windsor Star <http://www.windsorstar.com/news/national/cms/binary/9318821.jpg?size=640x420>.

Based on the information outlined in the AECOM-Toronto Hydro report entitled *Future Impacts of Climate Change on Toronto Hydro's Distribution System* (filed at Appendix A to this schedule), extreme weather events of this nature adversely affect Toronto Hydro's distribution system and will continue to do so in the future. The proposed climate adaptation study and pilot project would analyze, develop and test plans to make Toronto Hydro's distribution system more resilient to weather induced failure by reducing the time for restoring service to customers.

Toronto Hydro uses two fundamental measures of outage durations and outage frequency, namely System Average Interruption Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). One of the sub-categories for both SAIDI and SAIFI tracks the impact of adverse weather specifically. In both metrics major event days (MEDs) (i.e. atypical events that are beyond the design or operational limits of the system) are put aside from historical tracking because they can distort perception of the utility's reliability performance. However, because of the nature of the climate adaptation study, it is relevant to look at how MEDs affect Toronto Hydro's distribution system.

Table 3 shows the total annual SAIDI for adverse weather excluding MEDs, and the average annual SAIDI from 2000-2013 for these values.

TABLE 3: AVERAGE ANNUAL SAIDI DUE TO ADVERSE WEATHER

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual SAIDI excluding MEDs (min)	40.5	33.3	35.6	35.0	18.4	19.8	26.9	26.5	26.6	28.9	32.8	38.2	16.8	30.5
Average Annual SAIDI from 2000 to 2013, excluding MEDs = 29.3 minutes														

By definition, MEDs can have a significantly higher than average impact on SAIDI. Toronto Hydro experienced two MEDs recently: the July 8, 2013, flood with a SAIDI total of 197.26 minutes, and the December 21 to the 26, 2013, ice storm with a preliminary SAIDI total of 990.7 minutes. Both MEDs far exceeded the average adverse weather SAIDI count for an entire year, demonstrating the extreme impacts adverse weather has on Toronto Hydro's distribution system. For further information on recent weather events affecting network performance refer to Future Impacts of Climate Change on Toronto Hydro-Electric System Limited (Appendix A)

The proposed climate adaptation study would assist Toronto Hydro in the implementation of the overhead and underground programs by focusing on the identification of areas of the system that are vulnerable to extreme weather. This will consist of a logical breakdown of the distribution system at a system level and a matrix comparison between different weather scenarios, highlighting areas affected by changing climate.

Other electrical utilities have also conducted studies on climate adaptation and have developed climate adaptation programs based on the findings to move underground equipment out of flood plains, or elevate equipment where possible to remove the hazard. Where removal of equipment is not possible, equipment upgrades could be implemented in flood zones to incorporate submersible equipment that would not be as vulnerable to the water. For more detail on what other electrical utilities are developing for climate adaptation please refer to (Future Impacts of Climate Change on Toronto Hydro-Electric System Limited in Appendix A). Overhead equipment, which endures the most pressure from extreme weather, would also be examined; in certain areas where power supply is critical, system reconfiguration may be used to increase reliability and the integrity of the overhead distribution system.

Future increases in temperature could have adverse effects on the Toronto Hydro distribution system as well. It is forecasted that in 100 years, increased temperatures could produce a 10 percent reduction in efficiency of the distribution system. Potential mitigation programs can look at changing the amount of energy consumed by customers through new technologies.

The proposed climate adaptation study would include pilot projects to test feasibility of the recommendations. The benefit of testing the study’s recommendations before system level implementation is to ensure the most effective solutions go forward. These proposed pilot projects are included in the forecasted expenditures for the program.

At this point in time, there are many solutions Toronto Hydro could use to mitigate climate change impacts. However, in order to ensure the correct steps are taken, two years of studies and pilot projects will be used to identify the critical path for future climate adaptation programs.

(ii) Customer Interruption Costs

The proposed CIC study would help further enhance customer interruption cost inputs used within the Feeder Investment Model (FIM), which is further detailed in Section D3. Customer Interruption Costs are defined as a measure of the monetary losses for customers due to an interruption of electric service. The inconvenience and damage encountered by customers involves three periods:

(1) The first period is immediately after power interruption. Customers need to take the necessary action to mitigate the immediate effects of the interruption risks to health and welfare of employees, tenants or the public, production impacts, and other business and non-business activities. This first period can be monetized as per the formula shown below:

(a) Event Cost = ($SAIFI_{EFFECT}$)(Total Load)

Where:

- $SAIFI_{EFEECT}$ (\$30) represents the cost associated with this first period of the interruption.
- Total Load represents the peak load that will be interrupted due to the outage event.

(2) The second period follows, with on-going disruption to production, sales, office work and entertainment. In this period the customer interruption cost is proportional to the duration of power failure. This second period can be monetized as per the formula shown below:

(a) Duration Cost = (SAIDIEFFECT)(Total Load)(Outage Duration)

Where:

- $SAIDI_{EFEECT}$ (\$15) represents the cost associated with this second period of the interruption.
- Total Load represents the peak load that will be interrupted due to the outage event.
- Outage Duration represents the average duration of the outage event in hours.

(3) The third period is after the restoration of power when customers take action to resume normal production.

As noted above, Toronto Hydro has adopted the use of a \$30/kVA (peak load) customer interruption cost value to represent the first period of the outage (the “Event”) and a \$15/kVA-hour (peak load) customer interruption cost value to represent the second period of the outage (the “Duration”). These costs were developed with input from consultants, who have worked with other utilities in establishing similar parameters. Reliability valuation studies, such as those from Roy Billinton, were used to aid in the development of these parameters, which are applied consistently to quantify power interruptions to all types of customers. Due to the immediate termination of regular activities involving electricity during the first period of the outage, it is expected that the costs associated with this period will be larger in comparison to the second period, where the customer has now re-adjusted their activities to account for the loss of electricity. It is during the second period, however, that the inconvenience and disruption associated with the outage will continue to grow as the outage continues to linger. Therefore, the monetized value associated with this stage will be multiplied with the duration of the outage, in hours.

The customer interruption cost study proposed within Program Support will further enhance the $SAIFI_{EFFECT}$ and $SAIDI_{EFFECT}$ inputs through the development of a localized customer survey for the City of Toronto, which will better reflect the specific needs and preferences of Toronto-area customers. Furthermore, it should be noted that during the ICM interrogatories, both the interveners and the OEB Staff[4] recommended that Toronto Hydro look into the "use of surveys on the various customer classes to determine the units of [outage costs per customer class] as recommended by experts in that field". Toronto Hydro believes that conducting this study will help in the development of localized outage costs that address these concerns from various stakeholders.

E8.8.4 Timing & Pacing of the Program

Toronto Hydro plans to conduct these two studies to help mitigate the impact of the extreme weather and further enhance the FIM through localized outage costs. The spending forecast for the five-year period starting in 2015 is shown below in Table 4.

TABLE 4: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	0	0	0	0	0	1.2	0.5	0	0	0

Toronto Hydro plans to conduct the climate adaptation study in 2015 and 2016 while the CIC study is expected to be completed in 2015. The proposed total costs for climate adaptation study is $1.0 million over the two years with a budget of $0.5 million each year, while the CIC study is expected to cost $0.7 million.

[4] EB-2012-0064, Board Staff Submission (September 30, 2013), at page 13.

It is preferable to complete the climate adaptation study in the first two years of the DSP period. Upon completion of the climate adaptation study, Toronto Hydro would review its existing plans through the FIM, and compare the results to existing programs Toronto Hydro is currently executing, to benefit from any cross-program synergies or to build on exist existing programs that may already be building on system resiliency. The CIC study is planned for completion in 2015 because the localized outage costs calculated will have to be tested and gradually incorporated into the FIM to further enhance the model in preparation of prioritization of projects in the later years of the DSP period.

E8.8.5 Program Execution

Both of the studies in this program are planned for the first two years (2015-2016) of the DSP period as shown in Table 5. The climate adaptation and the CIC studies are expected to be completed in 2015-2016 and 2015 respectively. Toronto Hydro plans to contract out both studies on a competitive bid basis, while working closely with the vendors to provide the required data and direction.

TABLE 5: PROPOSED WORK PLAN

Year	Program Support
2015	CIC Study
2015	Climate Adaptation
2016	Climate Adaptation

The climate adaptation study in 2015 and 2016 would focus on identifying areas of vulnerable to extreme weather and climate change in the distribution system. The starting point of the studies would pick up where previous programs have left off. (Refer to Toronto Hydro's Actions to Date in Appendix A; Future Impacts of Climate Change on Toronto Hydro-Electric System Limited). Specifically, the study would start by looking at extreme weather event scenarios that are expected to increase in future climate change projections. These scenarios include but are not limited to flooding, freezing rain, increase in temperature, and ice-storm etc. In each scenario thresholds and boundaries would have to be created to identify what areas of the distribution system will be affected. In some cases where information is not readily available external parties will be engaged. Once thresholds and boundaries of each extreme weather scenario are known, a detailed engineering analysis of impacts from each event will be created.

For the CIC study, a vendor would be selected based on past experience conducting extensive outage costs surveys for different scenarios and across different customer demographics. Most importantly, the preferred vendor should possess sufficient experience with the cost estimation methodologies described earlier in the narrative. Due to the survey nature of this study and Toronto Hydro's customer base, it is critical to ensure adequate customer representation and random sampling to mitigate sampling bias in the survey participants.

Following vendor selection, Toronto Hydro would work with the vendor to develop the questionnaire and expects to complete the survey by end of Q3 2015. The vendor would be expected to process the surveys and analyze the results and provide a final report. The goal is to complete the survey by end of Q4 2015.

E8.8.5.1 Program Risks

Both studies in this program would require external the involvement of external experts with proven experience in their fields. This is especially important for the CIC study. The CIC study requires a group with background in statistics (to ensure the right sample mix and no sampling bias exists), economics (quantify outage costs), survey design and execution. Toronto Hydro plans to reach out to authors of previous CIC studies, among other potential vendors.

E8.8.6 Evaluation of Alternatives

E8.8.6.1 Quantification/Evaluation of Options

(i) Status Quo

In the absence of these two proposed studies, plans to adapt to climate change within Toronto Hydro's distribution system would be derived solely from historical information and trends in weather-related events. Table 2 illustrates how customer interruptions associated with weather events would continue to increase due to the higher frequency of extreme weather. Similarly, Toronto Hydro would continue using existing customer interruption cost (CIC) inputs as part of their Feeder Investment Model (FIM) and business case evaluation (BCE) process.

This option is not preferred as it does not address the expected impacts of climate change and would not allow for the enhancement of CIC estimates.

(ii) Execution of Program Support

Through the execution of this program, Toronto Hydro would improve its Asset Management capabilities, including long-term and short-term planning processes, thereby allowing for improvements to capital programs and projects respectively.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 32:

Reference(s): Exhibit 2B, Section A6, p. 32

Toronto Hydro states that it's currently undertaking a CIC (customer interruption cost) study.

a) Please provide more about the study.

b) Please provide a copy of any study work plans, charters, or similar guiding documents.

c) Please provide details, including a copy, of any preliminary results of the study.

RESPONSE:

a) The Customer Interruption Cost (CIC) study engaged customers through a survey-based approach to help establish City of Toronto-specific CIC values. Toronto Hydro is currently in the process of completing the study. As part of the study, Toronto Hydro's customers were surveyed – including residential, small and medium businesses, and large customers (>1MVA) – regarding their reliability experience and potential costs of power interruptions. Although information from the surveys is available, Toronto Hydro must still perform substantial analysis of the results to update the current Event costs and Duration costs used for CIC evaluation and integrate the results into its tools for use in planning procedures.

b) Please refer to Appendix A for the Request for Proposal (RFP) that Toronto Hydro issued which provides details on the scope of work for the study.

c) Please see response to part (a). As the study remains incomplete, preliminary results are not available at this time.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 81:

Reference(s): Exhibit 2B, Section E6.2, pp. 2, 22, 26, 28, 31-32

a) Toronto Hydro plans to prioritize the replacement of underground transformers that are at risk of failure, which are known to, or at a risk of, containing PCB-contaminated oil (Exhibit 2B / Section E6.1 / p. 2). Please explain how Toronto Hydro will know when all PCB-contaminated equipment has been eliminated as there is no accurate database of this inventory (in the context of Toronto Hydro's statement that it will prioritize replacement of underground transformers that are at risk of containing PCB-contaminated oil).

b) Please reconcile the statement that 723 switches are at or beyond their useful life as of 2017 (Exhibit 2B / Section E6.2 / p. 26) with the information in Table 8 (Exhibit 2B / Section E6.2 / p. 22).

c) Toronto Hydro states that its 2020-2024 underground circuit renewal budget is based on historical unit cost trends (Exhibit 2B / Section E6.2 / p. 28). Please provide the historical and forecast unit costs for underground cable, transformers and switches. Please show how historical costs have influenced the forecast capital budget.

d) Please provide the total cost of Option 1 (spot replacement of transformers in deteriorated condition at or beyond their useful life) and Option 2 (area rebuilds) for the 2020-2024 period (Exhibit 2B / Section E6.2 / pp. 31-32). Please compare to the total cost of the selected option for the same period.

RESPONSE:

a) Toronto Hydro has developed a full list of "PCB at-risk equipment".[1] As described in Exhibit 2B, Section E2 at page 36, Toronto Hydro's strategy is to inspect, test, or replace each and every piece of equipment on that list. As these activities are completed, Toronto Hydro will remove equipment from the list when it no longer contains PCBs (i.e. below 2ppm). Removal of all equipment from the list will be used as the indicator that all PCB-contaminated equipment has been eliminated.

b) The 723 switches at or beyond their useful life (in Exhibit 2B, Section E6.2, at page 26) includes both pad mounted and vault installations whereas Table 8 (in Exhibit 2B, Section E6.2, at page 22) shows data for pad-mounted switches only. Underground Switches age demographic as of 2017 is shown in Figure 20 of Exhibit 2B, Section E6.2, at page 25.

c) Please see Table 1 below.

Table 1: Historical Unit Costs (2015-2017) for Major Units

Asset	2015	2016	2017	2015-2017 Average	2020 Forecast
Cable ($/m)	$100	$96	$125	**$107**	$115
Transformers ($/unit)	$22,697	$23,091	$20,596	**$22,128**	$22,767
Pad-Switch (S/unit)	$83,479	$81,611	$81,798	**$82,296**	$87,333

Note: The 2020 forecast was based on the 2015-2017 Average and escalated to 2020 dollars using 2% escalation per year. 2021 to 2024 forecasts, which are not shown in the table, were developed using the same escalation.

[1] "PCB at-risk equipment" is defined in Exhibit 2B, Section D.2.2 at page 14, as equipment that (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"), or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCBs). Please see the seventh column of Exhibit 2B, Section D2, Table 1 on page 12 for summary statistics.

The forecasted costs were directly influenced by unit costs contained in the table as these were used to estimate the aggregate cost associated with installing cable, transformers, and switches. In addition to the aggregate costs for cable, transformers, and switches, estimated costs for civil elements and other equipment were added to arrive at the overall forecasts.

d) The total cost for the Options 1, 2 and 3 are provided in Table 2. These are total costs for 2020-2024 period based on 2017 costs excluding inflation and other allocations.

Table 2: Costs for Underground Circuit Renewal Options 1, 2 and 3 ($ Millions)

Options	2020-2024[1]
Option 1: Spot replacement of transformers in deteriorated condition at or beyond their useful life	123.4
Option 2: Area Rebuilds	469
Option 3: Area rebuilds and Spot replacement of transformers at or beyond their useful life	349[2]

Note 1: Costs in this column are 2017 dollars and excludes inflation and other allocations.
Note 2: $460.3 million including inflation and other allocations.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 84:

Reference(s): Exhibit 2B, Section E6.5, pp. 17-18

Toronto Hydro states that it will have spent almost 25% more on overhead system renewal during the 2015-2019 period than planned (Exhibit 2B / Section E6.5 / p. 17) due to increased work volume. Please provide a comparison of the 2015-2019 planned number of overhead unit replacements and actual (or most recent forecast) number of overhead unit replacements in the same format as Table 7 (Exhibit 2B / Section E6.5 / p. 18).

Toronto Hydro states that its 2020-2024 forecast capital expenditures related to overhead system renewal is based on the historical unit cost trends (Exhibit 2B / Section E6.5 / p. 18). Please provide the historical and forecast unit costs for poles, transformers, overhead switches and conductors (per km). Please show how historical costs have influenced the forecast capital budget.

RESPONSE:

a) Toronto Hydro notes that the preamble to the question incorrectly paraphrases the utility's evidence. It is only in 2015 and 2016 that Toronto Hydro undertook a greater work volume. As noted in Exhibit 2B, Section E6.5, page 18, Toronto Hydro ramped down volumes of work in this program in 2017 through 2019. Please see Table 1 below for the 2015-2019 actual and planned overhead volumes of work.

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

Asset Class	2015		2016		2017		2018[1]		2019	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Plan	Forecast
Poles	3332	3656	1735	2692	1900	1513	1934	1100	2313	550
Pole Top Transformers	972	940	511	769	478	441	598	575	673	290
Overhead Switches	294	192	160	167	166	120	154	55	207	35
Primary Conductor (km)	N/A	155	N/A	179	N/A	123	N/A	70	N/A	63

b) Table 2 below shows the historic unit cost trends of the major overhead assets included in Table 1 in part (a).

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

Asset Class	Actual			Forecast	
	2015	2016	2017	2018 F[2]	2019 F
Poles	$7,880	$7,538	$6,454	$7,385	$7,533
Pole Top Transformers	$12,084	$12,220	$10,969	$11,823	$12,059
Overhead Switches	$21,994	$26,359	$18,336	$24,660	$25,153
Primary Cables ($/km)	$59,500	$63,200	$60,400	$62,577	$63,829

The 2020-2024 forecasts are based on historical unit costs plus an inflation factor of 2 percent as shown in Table 3 below:

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

Asset Class	2020	2021	2022	2023	2024
Poles	$7,684	$7,837	$7,994	$8,154	$8,317
Pole Top Transformers	$12,300	$12,546	$12,797	$13,053	$13,314
Overhead Switches	$25,656	$26,169	$26,693	$27,227	$27,771
Primary Cables ($/km)	$65,105	$66,407	$67,735	$69,090	$70,472

[1] The Planned units provided for 2018 and 2019 are Toronto Hydro's most recent forecasts.
[2] The 2018 and 2019 unit costs are based on the weighted average of 2015 -2017 unit costs, plus 2% inflation factor.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 11:

Reference(s): **Exhibit 1B**
Exhibit 2B
Exhibit 4A

Please provide details of all material productivity initiatives (capital and/or OM&A) that are planned to be undertaken during the test period. Please provide the estimated cost savings achieved and how those savings were calculated.

RESPONSE:

Please see Toronto Hydro's response to interrogatory 1B-CCC-14.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 14:

Reference(s): Exhibit 1B, Tab 1, Schedule 1, p. 21

The evidence states that THESL has proposed a ratemaking framework for this Application that provides incentives for the utility to seek out further productivity and efficiency improvements over the 2020-2024 period. Please explain how the rate framework incents productivity. Please set out for each year 2015-2019 the productivity gains achieved for both OM&A and Capital. What are the specific productivity initiatives expected for the period for 2020-2024 both with respect to capital and OM&A? Please provide a detailed list.

RESPONSE:

As described in Exhibit 1B, Tab 2, Schedule 1, Toronto Hydro is proposing an incentive-based rate framework that encourages the utility to continuously seek efficiencies. This incentive is created by including the OEB's productivity factor and a custom stretch factor in the custom Price Cap Index ("PCI"). In doing so, Toronto Hydro is committing to share with its customers the benefits of these efficiencies before they are realized, by directly reducing rates funding. This approach provides customers with a guaranteed, up-front share in productivity generated by the utility.

The evidence in Exhibit 1B, Tab 2, Schedule 1 provides an overview of Toronto Hydro's historical productivity and performance, including specific examples of productivity and process improvements at Exhibit 1B, Tab 2, Schedule 1, at pages 8 through 20. For additional examples over the 2015-2019 period, please refer to the OM&A program evidence at Exhibit 4A, Tab 2 (Cost Management and Productivity sections of each OM&A

program and segment), and the Capital program evidence at Exhibit 2B, Sections E5 through E8. Specific interrogatory responses also provide additional details: see for example, Toronto Hydro's response to 2B-BOMA-77.

The references to the OM&A and Capital programs above also detail examples of the investments and initiatives that will support the utility's efforts to control costs and increase productivity over the 2020-2024 period. For example, Exhibit 2B, Section A4.4 highlights some of these activities including: grid modernization, capacity improvements, standardization, area rebuilds, conservation first, safety and environmental costs, enhanced work coordination, and facilities asset management system and procurement.

At this time, Toronto Hydro is unable to quantify the estimates of cost savings of the planned initiatives. As part of continuous improvements throughout the plan period, Toronto Hydro intends to evaluate the operational efficiencies gained, as well as the reduced and avoided costs. The cost savings realized will help Toronto Hydro to realize the savings required by the incentive-based rate framework that encourages the utility to continuously seek efficiencies by including the OEB's productivity factor and a custom stretch factor in the custom PCI, and to deliver on the planned outcomes 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

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0049

HYDRO ONE NETWORKS INC.

Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

BEFORE: Ken Quesnelle
Presiding Member

Emad Elsayed
Member

Lynne Anderson
Member

March 7, 2019

3.2.3 Capital Factor (Issue 9)

Issue 9. Are the values for the proposed custom capital factor appropriate?

Hydro One has proposed a capital factor to provide incremental funding for new capital investments during the term. The capital factor was modelled based on a similar factor approved for Toronto Hydro in its 2015 Custom IR rate proceeding.[57] The capital factor calculates a percentage change in the revenue requirement attributable to new capital investment that is not being funded through the inflation less expected productivity (I - X) adjustment. The calculation includes depreciation, return on equity, return on debt and taxes attributable to new capital investment placed in-service for 2019 to 2022 of the Custom IR term.

For Hydro One's proposed capital factor the revenue requirement would increase by the following percentages each year to provide funding for incremental capital,[58] in addition to the inflation less expected productivity (I – X) adjustment:

Table 3
Hydro One Proposed Capital Factor

	2019	2020	2021	2022
Capital Factor	2.32%	2.21%	3.14%	1.69%

Hydro One stated that the capital factor is required in order to ensure that it can invest in its capital as required by the DSP, and in order to meet customer expectations in relation to reliability.

PWU supported Hydro One's proposed capital factor.[59]

AMPCO did not oppose the proposed capital factor, but submitted that if there is an application update for 2021, the capital factor should be reviewed and updated. The update would be based on the variance between actual versus forecasted capital spending during the first three years of the plan (i.e., 2018-2020).[60] Similarly, CCC

[57] EB-2014-0116.
[58] Letter filed by Hydro One on the Hydro One Accountability Act, October 26, 2018, page 6.
[59] PWU, *op. cit*., p. 10.
[60] AMPCO, *op. cit*., pp. 5-6.

submitted that the OEB should approve a capital factor for the 2018-2020 period, with Hydro One reporting on the achieved results to set the capital factor for 2021 and 2022.[61]

VECC was opposed to the capital factor, submitting that it is "not consistent with the principles of incentive rate making and does not follow the intent of the RRFE framework."[62] BOMA also expressed concerns regarding the capital factor, submitting that it lessened the incentive to impose discipline on capital spending, and was more permissive than the OEB's IRM and incremental capital module (ICM) framework.[63]

CME submitted that the working capital portion should be removed from the rate base calculation used for determining the capital factor. CME argued that the return on debt, return on equity and income taxes associated with the working capital allowance component of rate base have nothing to do with the capital expenditures and additions that result from the DSP.[64]

Hydro One submitted that its large capital requirements on an on-going basis preclude it from the OEB's traditional Price Cap IR mechanism, referring to the Rate Handbook, the RRFE Report and related OEB documents on capital funding mechanisms.[65]

Hydro One disagreed with CME that working capital should not be included in the calculation of the capital factor because the inclusion of working capital:

- is consistent with prior decisions[66]
- represents a prudently incurred cost
- allows for the integration of the additional working capital requirements of the Acquired Utilities

Findings

The OEB approves the approach to the capital factor as proposed by Hydro One, but imposes an additional 0.15% stretch factor to be subtracted from the calculated capital factor. This is in addition to the 0.45% stretch factor applied to the revenue requirement

[61] CCC, *op. cit*., pp. 8-9.
[62] VECC, *op. cit*., p. 8.
[63] BOMA, *op. cit*., pp. 6-8.
[64] CME, *op. cit*., pp. 8-9.
[65] Hydro One, Reply Argument, *op. cit*., pp. 30-32.
[66] Toronto Hydro-Electric System Limited, Decision and Order EB-2014-0116, December 29, 2015.

and the reductions to the capital program discussed under Issue 30. Hydro One is directed to recalculate the capital factor to reflect the OEB's findings on its capital program and to include the incremental stretch factor.

Hydro One has argued that the 0.45% stretch factor inherent in the (I – X) adjustment is applied to the revenue requirement, and therefore applies to both OM&A and capital. The difference between the treatment of OM&A and capital with Hydro One's proposal is that funding for OM&A is not based on a forecast of OM&A costs. For OM&A, Hydro One is expected to manage within an increase of less than inflation (I – X) each year, regardless of its forecast costs. This is to incent the company to find productivity improvements. For capital, however, Hydro One has forecast capital expenditures for each year of the term, and is seeking funding for any incremental capital not funded by the (I – X) adjustment. The rate base from these forecast capital expenditures is increasing by more than inflation.

Hydro One has said that it has developed productivity initiatives and embedded these in its business plan for both OM&A and capital, with respective managers accountable for delivering the expected savings.[67] Hydro One provided a governance document[68] that explains the process for tracking and reporting on these productivity initiatives. For capital, the initiatives included Move to Mobile, Procurement and Telematics for a total of $184.7 million of expected savings from 2018 to 2022, which is only 5.2% of the total proposed capital expenditures of $3,571.3 million.[69]

The OEB agrees that this process of defining, executing and reporting on productivity initiatives is an enhancement to Hydro One's planning. The OEB expects Hydro One to stretch itself more to find additional initiatives and to consider new approaches to its business. The OEB is therefore imposing an additional stretch factor for the capital factor of 0.15% to incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront.

In imposing this stretch factor, the OEB also recognizes the argument made by intervenors that for the last rate framework term, Hydro One overspent on in-service capital by $122.5 million, approximately 6.2% more than approved.[70] The OEB is approving the inclusion of this capital in the 2018 rate base because it is appropriate for a distributor to reprioritize work to meet changing circumstances. However, in

[67] Exhibit B1-1-1, DSP Section 1.5, page 2 and Exhibit B1-1-1 DSP Section 1.1, page 10.
[68] Exhibit B1-1-1 Section 1.4 Attachment.
[69] Letter from Hydro One, re: Hydro One Accountability Act, October 26, 2018, page 5.
[70] Tr. Volume 6 page 134.

Findings

The OEB finds that Hydro One has taken steps to improve its performance measurement and its monitoring and reporting compared to its last rate application. There are, however, a number of areas where further improvement should be made, including:

- having targets for all measures for each year in the rate period
- demonstrating that these targets represent sufficiently challenging targets relative to past performance and other benchmarks in the spirit of continuous improvement

Hydro One is directed to demonstrate, in its next rebasing application, that proposed performance targets are set for each measure and each year, and that they represent an improvement relative to past performance and other benchmarks. Hydro One is to provide detailed reasons for any gaps or exceptions.

3.3.3 Productivity Gains (Issue 21)

Issue 21. Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

Hydro One provided a number of different means for assessing its productivity in the application. Its PSE study provided an assessment that can be used in evaluating expectations for gains relative to external benchmarks. In addition, the Electricity Distributor Scorecard filed by Hydro One as part of the initial evidence[113] included some industry performance indicators for service quality and customer satisfaction to which Hydro One's own targets could be compared.

Hydro One also included quantified productivity gains in its forecasts. These were provided in the original evidence and then updated in response to an interrogatory as shown in Table 4 below:[114]

[113] Exh. A Tab 5, Sch 1, p. 8 Filed: 2017-03-31.
[114] Exh B1-01-01 Sec 1.5, pp. 1966-1967 Filed: 2017-03-31 and Exh I, Tab 25, Sch. Staff-123, p. 2 Filed: 2018-02-12.

Table 4

Hydro One Productivity Savings Forecast

$ millions

	2018	2019	2020	2021	2022	Total
Capital	36.4	34.2	37.8	37.3	39	184.7
OM&A	29.4	33.7	40.9	42.9	45.5	192.4
Corporate Common	4.0	4.2	4.2	4.2	4.2	20.8
Total	69.8	72.1	82.9	84.4	88.7	397.9

Hydro One provided a detailed breakdown of the individual projects that contributed to these totals and the amount of the savings expected to be generated from each of them.

OEB staff and intervenors expressed concerns that Hydro One's determination as to what constitutes a productivity gain appears to be very subjective. It was also not clear whether corresponding headcount reductions for these projects represent a net reduction for Hydro One or just staff moving from one part of Hydro One to another.

It was submitted that Hydro One should be directed to clearly demonstrate in future applications how its claimed productivity savings achieve quantifiable cost savings that will reduce costs for the distribution ratepayer (e.g. absolute headcount reductions that can be specifically related to the productivity initiative).

Findings

The OEB has concerns about how the claimed productivity gains were presented and supported by Hydro One. The OEB findings in this area are detailed under Issues 10 and 25.

3.3.4 Managing within the Custom IR Plan (Issue 22)

Issue 22. Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

Hydro One stated that it is committed to managing within the revenue requirement proposed over the course of the Custom IR plan term in a reasonable and appropriate manner. Where the capital portion of the revenue requirement is concerned, Hydro One expressed its commitment to spending within the proposed amounts as it is at risk for capital overspending during the plan and will have to justify any In-Service Additions

Full-service consultants

Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels

Prepared at the Request of:

Toronto Hydro-Electric System Limited

Prepared by:

Power System Engineering, Inc.

July 16, 2018

www.powersystem.org

The next table and figure break down the benchmark total costs and company total costs from 2005 to 2024. Toronto Hydro has consistently been below its expected benchmark levels. During the most recent historical period of 2015 to 2017, Toronto Hydro's costs are 18.6% below the benchmark values. During the CIR period of 2020 to 2024, Toronto Hydro's costs are 6.0% below the benchmark values on average.

Table 7 Toronto Hydro's Cost Performance 2005-2024

Year	Toronto Hydro Actual Costs ('000, C$)	Toronto Hydro Benchmark Costs ('000, C$)	% Difference (Logarithmic)
2005	$ 436,128	$ 641,275	-38.6%
2006	$ 450,686	$ 681,212	-41.3%
2007	$ 502,433	$ 744,486	-39.3%
2008	$ 556,429	$ 813,528	-38.0%
2009	$ 595,932	$ 852,775	-35.8%
2010	$ 647,456	$ 882,130	-30.9%
2011	$ 710,544	$ 912,729	-25.0%
2012	$ 691,388	$ 910,814	-27.6%
2013	$ 727,152	$ 925,488	-24.1%
2014	$ 777,414	$ 976,095	-22.8%
2015	$ 826,886	$ 1,024,030	-21.4%
2016	$ 861,394	$ 1,034,492	-18.3%
2017	$ 904,560	$ 1,061,642	-16.0%
2018 (projected)	$ 964,885	$ 1,095,430	-12.7%
2019 (projected)	$ 999,492	$ 1,122,407	-11.6%
2020 (projected)	$ 1,044,567	$ 1,148,601	-9.5%
2021 (projected)	$ 1,085,324	$ 1,174,549	-7.9%
2022 (projected)	$ 1,134,689	$ 1,201,662	-5.7%
2023 (projected)	$ 1,180,820	$ 1,229,463	-4.0%
2024 (projected)	$ 1,225,282	$ 1,257,907	-2.6%
Average % Difference			
2015-2017			**-18.6%**
2020-2024			**-6.0%**

TABLE 1: PROPOSED PERFORMANCE MEASURES FRAMEWORK

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

In developing the proposed measures, Toronto Hydro referred to the Section 5.2.3, Chapter 5 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*[1], which sets out the key parameters for measures or metrics supporting the applicants' Distribution System Plan filings. Toronto Hydro's proposed framework of measures is consistent with the OEB's expectations set out in the Chapter 5 Filing Requirements, and should provide the OEB with useful insights into the quality and sophistication of the utility's distribution planning and implementation activities, as well as Toronto Hydro's improvement in recent years.

For each proposed measure, (with the exception of new measures) Toronto Hydro provides performance results along with the associated trend over the recent years, describes the methodology used to calculate the measure and its implementation, and outlines the ways in which the measure informs and/or otherwise interacts with the utility's Distribution System Plan and the related processes. Where relevant, Toronto Hydro also describes the unique planning

[1] Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications*, (Toronto: Ontario Energy Board, 2013). ["*OEB Filing Requirements*"]

and implementation considerations that shape the measure's design and the utility's expectations as to its future performance levels.

Two of its proposed measures, namely the Construction Efficiency measures are still in early stages of their development and/or require further research/pilot studies to confirm viability. For these measures, Toronto Hydro cannot yet provide the OEB with five years of historical data, or outline in detail its expectations as to the performance levels over the 2015-2019 planning period because of their early stage of development. These measures will require substantial planning and analytical work over the CIR rate period. Nevertheless, Toronto Hydro has decided to advance them as a part of this application because they embody the spirit of continuous improvement underlying Toronto Hydro's culture and the OEB's Renewed Regulatory Framework for Electricity. By improving the scale, scope and sophistication of its performance measurement capabilities, and seeing early results of these measurements over the 2015-2019 CIR period, Toronto Hydro will put itself in a better position to gauge its capital work execution efficiency for the benefit of the ratepayers and the utility's shareholder.

Toronto Hydro has developed the above framework of performance measures based on the scope, scale and nature of investments comprising the 2015-2019 Distribution System Plan. Material changes to the nature and volume of investments approved by the OEB may therefore affect Toronto Hydro's ability to achieve anticipated performance levels over the planning timeframe.

C1.1.1 Manner of Reporting

Toronto Hydro proposes to report the results of its performance on all 12 measures on an annual basis. Given the amount of analytical work required to assemble, validate and finalize the performance results, Toronto Hydro intends to provide the reports to the OEB by June 30 of the year following the reporting year. For clarity, Toronto Hydro intends to submit the first planned DSP Performance Measure Report by June 30, 2016. This report would cover the utility's performance over the 2015 calendar year.

The proposed form of the report is a table, showcasing the results from the reporting year, alongside performance statistics for the preceding five years where such data is available.[2]

/C

[2] As is further discussed in Section 3.5 of this evidence, given the nature of the proposed "Construction Efficiency: Standard Asset Assembly Labour Inputs" measure, the utility's progress in this area cannot be easily conveyed in a table format. Accordingly, Toronto Hydro's progress on this measure will reported in the accompanying discussion document.

The table would be accompanied by a discussion document which provides: additional context for Toronto Hydro's performance on each of the measures, including year-over-year variance explanations; a discussion of planned and completed activities that may have a bearing on the utility's performance on one or more of the measures; and such other information as may be relevant to the explanation of the utility's annual results.

/C

Consistent with the OEB's decision to treat information relating to the cost difference between internal and external construction of projects in a confidential manner as part of this application,[3] Toronto Hydro proposes to file the annual results of the Construction Efficiency: Internal vs. Contractor Cost, in a confidential manner as well.

[3] EB-2014-0116, Decision on Confidentiality And Procedural Order No. 4 (January 7, 2014). /C

regular intervals. Reviewing the progress at one-year intervals will assist in providing the OEB regular updates regarding the plan progress.

C3.2 Planning, Engineering & Support Efficiency

C3.2.1 Measure Description

Planning, engineering, and other eligible administrative costs associated with capital program or project development are a component of Toronto Hydro's total capital costs. For the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the proportion of its total capital expenditures on distribution plant and associated civil infrastructure that is comprised of indirect planning, engineering and support labour costs related to this portion of the utility's capital expenditures. By measuring the resulting ratio and taking steps to ensure that it remains within or below the historical levels, Toronto Hydro plans to drive the efficiency and productivity of these processes, ultimately resulting in more cost-effective assets being put into service.

The eligible costs to be tracked for the proposed measure include capitalized labour costs associated with long-term, short-term planning functions, including development of the long-term system studies, capital investment programs and specific projects. Section D1 provides a high level summary of each of the planning processes, while Section D3 provides details with respect to the elements and outputs produced by each planning process. The work to develop and refine the utility's decision support systems is also included in Section D3.1.2.1. The formula for the proposed performance measure is as follows:

$$\text{Planning, Engineering \&Support Cost Efficiency}(\%) = \frac{\text{\$ Capital Planning, Engineering \& Support Spend (Dx Plant)}}{\text{\$ Total Capital Spend (Dx Plant)}}$$

Using a hypothetical example to illustrate the mechanics of this formula, if Toronto Hydro's total capitalized indirect labour costs related to electric distribution plant amounted to $5 million in a year, while the utility's total capital expenditures attributable to the distribution plant and associated civil infrastructure were $50 million, the resulting metric for the year in question would be:

$$\frac{\$5\text{M}}{\$50\text{M}} = 10\%$$

Toronto Hydro tracks the eligible costs through a thorough time-sheeting process. This process assigns indirect labour costs to capital, operating, or blended activities, in accordance with a detailed set of pre-established criteria. These criteria are approved by Toronto Hydro's senior management and reviewed for compliance with the applicable accounting frameworks. Given that the utility has had no experience in explicitly tracking its performance on this measure in the past, Toronto Hydro proposes to track the yearly results on a rolling five-year average starting in 2015, in order to reduce the effects of any one-time events that may affect the results. While a portion of eligible indirect labour costs such as regular salary and burden of full-time employees is typically "fixed" year-over-year, subject to headcount changes, a significant portion of these costs can vary year-over-year. The variability is caused by circumstances such as overtime use, implementation of new tools or process streamlining, or additional hiring to support the changes in the utility's capital program. Accordingly, by commencing the measurement of its indirect labour costs supporting its electrical distribution plant and the associated infrastructure, Toronto Hydro plans to be in a better position to assess and improve the efficiency of its indirect labour costing and resourcing through a variety of potential management decisions.

C3.2.2 Historical Performance Trends

While Toronto Hydro has not explicitly tracked the proposed metric in the past, the application of the proposed formula to the eligible portion of the utility's historical capital expenditures produces the results presented in Figure 9.

Over the past five years, the portion of Toronto Hydro's indirect labour costs relative to the total distribution plant-related capital expenditures has decreased from 13.1% in 2009 to 7.1% in 2013, for the average five-year value of 9.9%. Toronto Hydro attributes the improvement in this measure's results to the increasing size of the utility's capital work program and subsequent optimization of the available labour resources. Although part of this improvement is attributed to the staffing reductions and certain accounting changes (2011), Toronto Hydro has generally been able to manage an increasing capital work program with the smaller work force. In addition, the performance improvements are attributable to the increased efficiency of asset management processes through automation of many manual procedures and the use of decision support systems, detailed in Section D3.

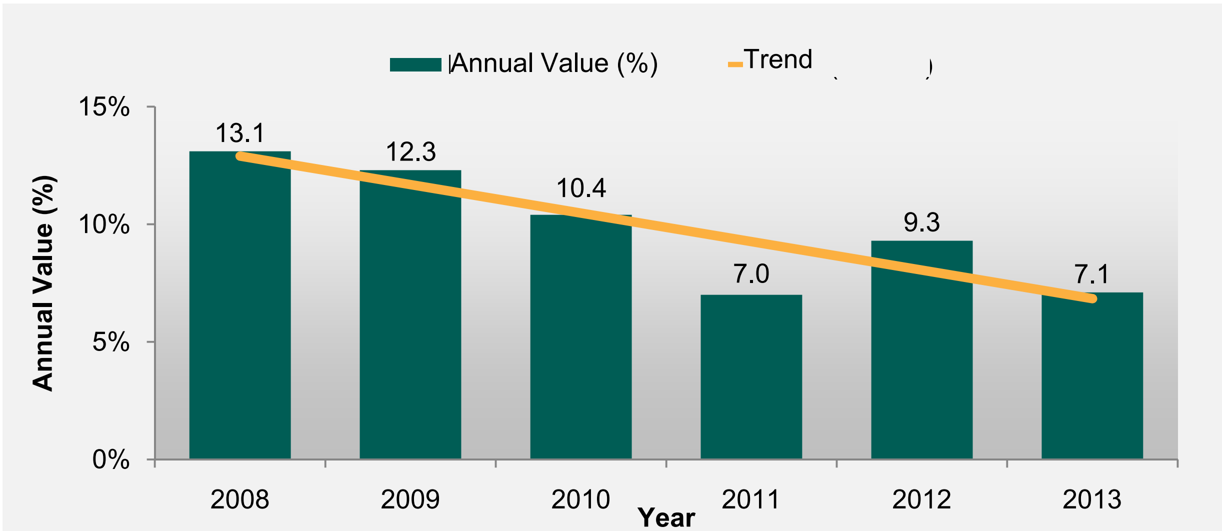

FIGURE 9: INDIRECT LABOUR % OF DX PLANT EXPENDITURES – 2009-2013

To gauge the appropriateness of its historic performance levels, Toronto Hydro consulted the 2014 edition of the *RSMeans Electrical Cost Data Book*[2] that provides the electric contractor industry with estimate ranges for a variety of electrical construction activities, including the proportion of total project costs made up of specific activities. A copy of the relevant information from this document can be found in Appendix A to this section of the DSP. According to the RSMeans data, the suggested total range of engineering costs as a portion of total project costs is within the 4.1% - 10.1% range. While Toronto Hydro's historical average result of 9.9% falls within the acceptable range, the utility notes that its indirect labour costs include other activities, such as management and support costs beyond the scope of activities captured by the RSMeans range.

For the purposes of its 2015-2019 capital plan, Toronto Hydro proposes to track the proportion of its indirect labour costs associated with electrical distribution plant relative to the total electrical distribution plant expenditures on a rolling five-year basis, with the 2009-2013 average value serving as a reference point. As the utility and the OEB gain more experience in this performance measurement area, Toronto Hydro may set more concrete targets in its future applications.

[2] RSMeans Electrical Cost Data Book, 2014 Edition, p 8.(See Appendix)

C3.2.3 Interaction with the Distribution System Plan

Toronto Hydro has no previous experience in tracking the proposed metric. Accordingly, the utility's current Distribution System Plan was not explicitly informed by any assumptions as to the capital planning, engineering, and support efficiency. By measuring these activities over the 2015-2019 timeframe, Toronto Hydro expects to gain valuable insights into this dimension of its capital work, while ensuring that the amount of supporting labour costs included in its distribution plant capital project costs remains appropriate.

C3.3 Supply Chain Efficiency: Materials On-Cost

C3.3.1 Measure Description

In accordance with the applicable accounting frameworks, Toronto Hydro adds the eligible portion of its supply chain and warehousing activities costs directly to the capital projects and programs that these activities support. The supply chain and warehousing costs are added to the total costs of capital projects through the service charge referred to as "On-Cost," which is applied as a percentage of the project's total costs. Since capitalized warehousing activities make up a material portion of each project's final costs, Toronto Hydro proposes to track the annual On-Cost value as a measure of efficiency of the utility's supply chain and warehousing activities.

Toronto Hydro calculates the On-Cost rate as the sum of budgeted eligible expenditures (e.g. warehouse employee labour costs), divided by the budgeted dollar value of materials moving through the utility's warehouses (including the recently outsourced warehousing operation) in a given year. The utility then applies the resulting rate to the dollar value of all materials when issued to capital and operating projects. At the end of each year, Toronto Hydro calculates the final on-cost rate on the basis of actual warehouse expenditures and the value of materials processed through the warehouse, and makes the appropriate adjustments to the capital costs of all projects.

Not all warehousing expenditures are included in the on-cost rate. For example, the inventory of materials used for internal warehousing purposes, utilities and communications-related expenses, and administrative staff costs are excluded. As with the indirect labour costs measure discussed above, Toronto Hydro's On-Cost calculation methodology is based on pre-determined parameters that are periodically evaluated.

C3.3.2 Historical Performance Trends

Figure 10illustrates Toronto Hydro's historical On-Cost rates and the associated performance trend. Toronto Hydro's On-Cost charges remained relatively flat between 2009 and 2013, with a 2009-2013 historical average of 11.8%. The utility attributes its generally steady On-Cost levels to better utilization of available resources, the increase of the overall volume of capital program and a number of efficiencies detailed in the Supply Chain Program OM&A evidence (Exhibit 4A, Tab 2, Schedule 12). Over the 2015-2019 planning horizon, the utility expects its On-Cost rate to decline because of anticipated attrition and other productivity and efficiency improvements, including the deployment of a third-party warehousing outsourcing model that began in 2013.

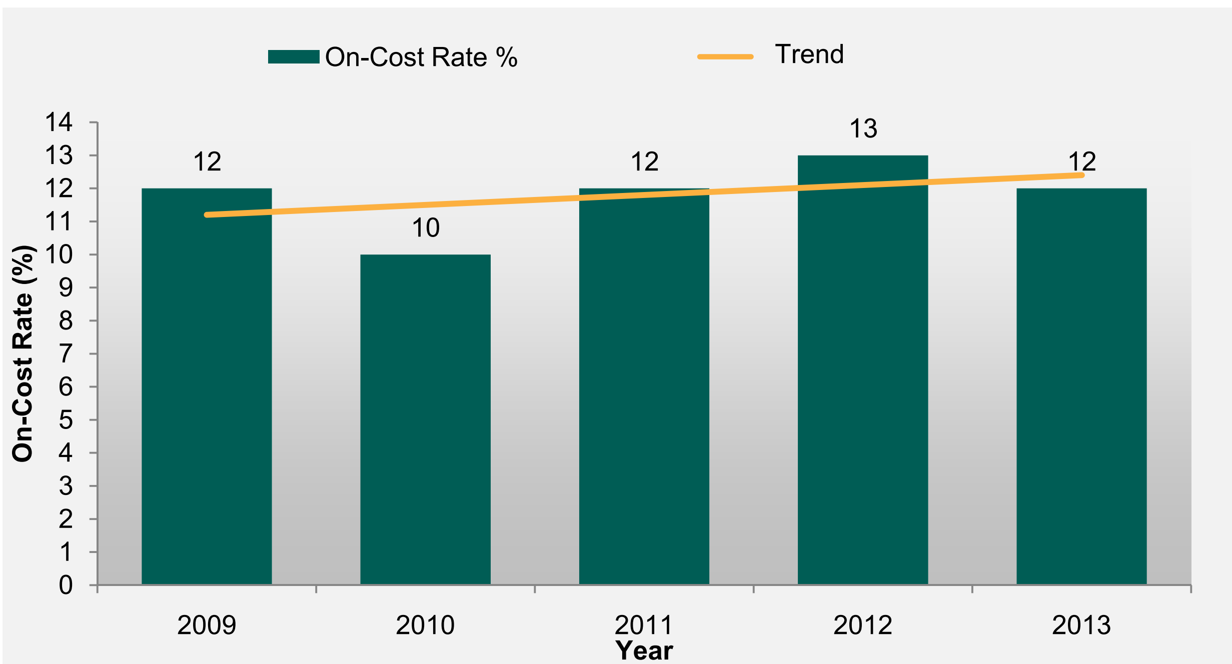

FIGURE 10: ON-COST PERFORMANCE (%) – 2009 – 2013

C3.3.3 Interaction with the Distribution System Plan

Subject to any developments outside of Toronto Hydro's control, Toronto Hydro's supply chain and warehousing efficiencies tracked through the On-Cost measure is expected to facilitate more cost-effective completion of the utility's capital program, enabling higher volumes of capital work to be completed for the same cost, thus directly benefiting Toronto Hydro ratepayers.

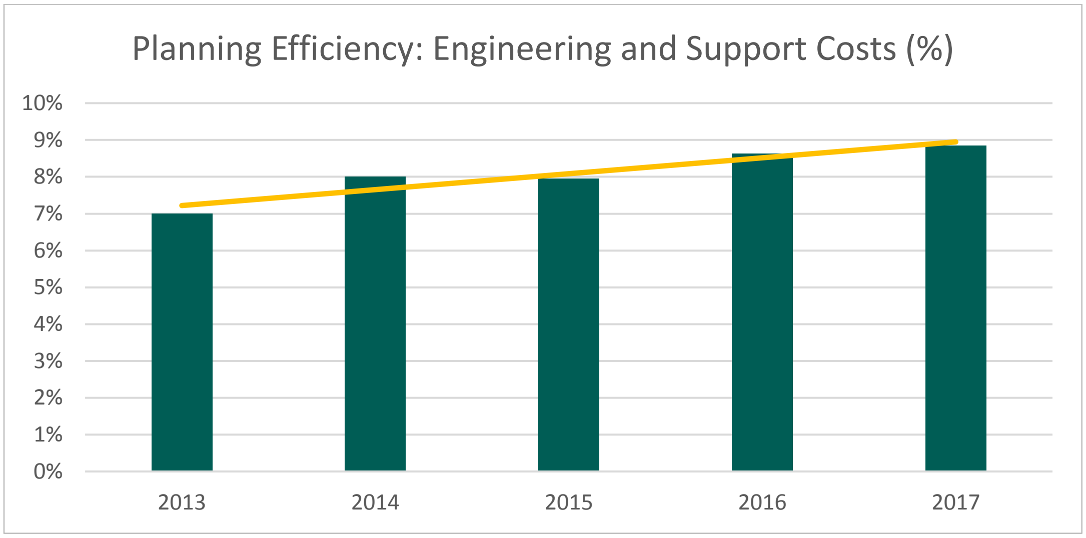

Figure 5: Engineering and Support Costs (%) Performance from 2013-2017

8. SUPPLY CHAIN EFFICIENCY: MATERIALS HANDLING ON-COST

In accordance with the applicable accounting framework, Toronto Hydro adds the eligible portion of its supply chain and warehousing activities costs directly to the capital projects and programs that these activities support. The supply chain and warehousing costs are added to the total costs of capital projects through the service charge referred to as “On-Cost”, which is applied as a percentage of the project’s total costs.

As shown in Figure 6, actual on-cost rate decreased between 2013 and 2017, with the general stability over the five-year historical period.

4.2 Stations Capacity Availability

The Stations Capacity Availability tracks the number of Transformer Stations where station demand is forecasted to exceed 90 percent of the station's firm capacity within the next five years. Figure 15 below shows the utility's performance in this measure over the 2013-2018 period. Two stations are forecasted to be loaded > 90% in the next five years.[5]

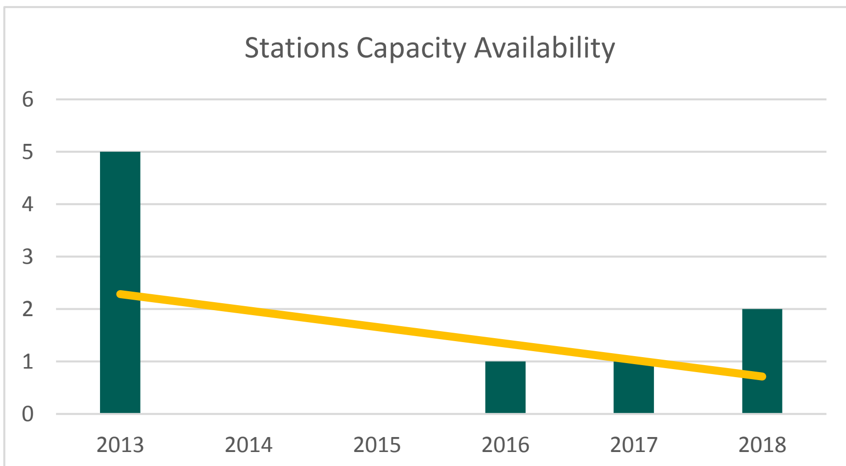

Figure 15: Stations from 2013 – 2018

4.3 Planning Efficiency: Engineering and Support Costs

This measure monitors the proportion of capital project expenditures attributable to indirect labour costs. The result of 10 percent for 2018 was comparable to the 2017 result of 9 percent.

[5] Please note that these are preliminary results and are subject to change based on additional loading analysis. Final results will be published in Toronto Hydro's final 2018 EDS.

7. 2018 CORPORATE SCORECARD UPDATE

In response to interrogatories 1B-SEC-8 and 4A-AMPCO-96, Toronto Hydro committed to providing the 2018 Corporate Scorecard. Table 5 below is the 2018 Corporate Scorecard updated to include 2018 results.

Table 5: 2018 Corporate Scorecard

Key Performance Indicator	2018 Target		2018 Result
New Services Connected on Time	96.5%		99.8%
Bill Accuracy	98.8%		99.3%
First Contact Resolution	86%		89%
Total Recordable Injury Frequency (TRIF)	1.45		0.83
Employee Engagement	6.0		7.1
SAIFI (# - Defective Equipment Only)	0.54		0.40
SAIDI (Minutes - Defective Equipment Only)	29.00		21.08
1-Year Distribution System Plan Investment ($M)	**Lower Target**	**Upper Target**	435.8
	418.0	451.0	
5-Year CIR Distribution System Plan Investment ($M)	**Lower Target**	**Upper Target**	1943.8
	1928.0	1957.2	
Consolidated Net Income ($M)	148.0		167.3

Table 4: 2018 Corporate Scorecard

Key Performance Indicator	2018 Target	
New Services Connected on Time	96.5%	
Bill Accuracy	98.8%	
First Contact Resolution	86%	
Total Recordable Injury Frequency (TRIF)	1.45	
Employee Engagement	6.0	
SAIFI (# - Defective Equipment Only)	0.54	
SAIDI (Minutes - Defective Equipment Only)	29.00	
1-Year Distribution System Plan Investment ($M)	Lower Target	Upper Target
	418.0	451.0
5-Year CIR Distribution System Plan Investment ($M)	Lower Target	Upper Target
	1928.0	1957.2
Consolidated Net Income ($M)	148.0	

Note 1: 2018 Results not yet available.

Table 5: 2019 Corporate Scorecard

Key Performance Indicator	2019 Target	
New Services Connected on Time	97.7%	
Bill Accuracy	99.0%	
First Contact Resolution	86%	
Total Recordable Injury Frequency (TRIF)	1.4	
Employee Engagement	6.5	
SAIFI (# - Defective Equipment Only)	0.52	
SAIDI (Minutes - Defective Equipment Only)	27.71	
5-Year CIR Distribution System Plan Investment ($M)	Lower Target	Upper Target.
	2341.2	2370.6
Net Income ($M)	160.6	

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 99:

Reference(s): Exhibit U, Tab 1C, Schedule 5, p.62;
1B-SEC-8, Table 5

Similar to what is provided in the 2018 Toronto AIF, please provide the weightings for the 2019 corporate scorecard.

RESPONSE:

Please see Table 1 below.

Table 1: 2019 Corporate Scorecard with Weightings

<table>
<tr><th>Key Performance Indicator</th><th colspan="2">2019 Target</th><th>Weight (%)</th></tr>
<tr><td>New Services Connected on Time</td><td colspan="2">97.7%</td><td>5</td></tr>
<tr><td>Bill Accuracy</td><td colspan="2">99.0%</td><td>5</td></tr>
<tr><td>First Contact Resolution</td><td colspan="2">86%</td><td>5</td></tr>
<tr><td>Total Recordable Injury Frequency (TRIF)</td><td colspan="2">1.4</td><td>10</td></tr>
<tr><td>Employee Engagement</td><td colspan="2">6.5</td><td>5</td></tr>
<tr><td>SAIFI (# - Defective Equipment Only)</td><td colspan="2">0.52</td><td>10</td></tr>
<tr><td>SAIDI (Minutes - Defective Equipment Only)</td><td colspan="2">27.71</td><td>10</td></tr>
<tr><td rowspan="2">5-Year CIR Distribution System Plan Investment ($M)</td><td>Lower Target</td><td>Upper Target</td><td rowspan="2">10</td></tr>
<tr><td>2341.2</td><td>2370.6</td></tr>
<tr><td>Net Income ($M)</td><td colspan="2">160.6</td><td>40</td></tr>
</table>

RESPONSES TO 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:

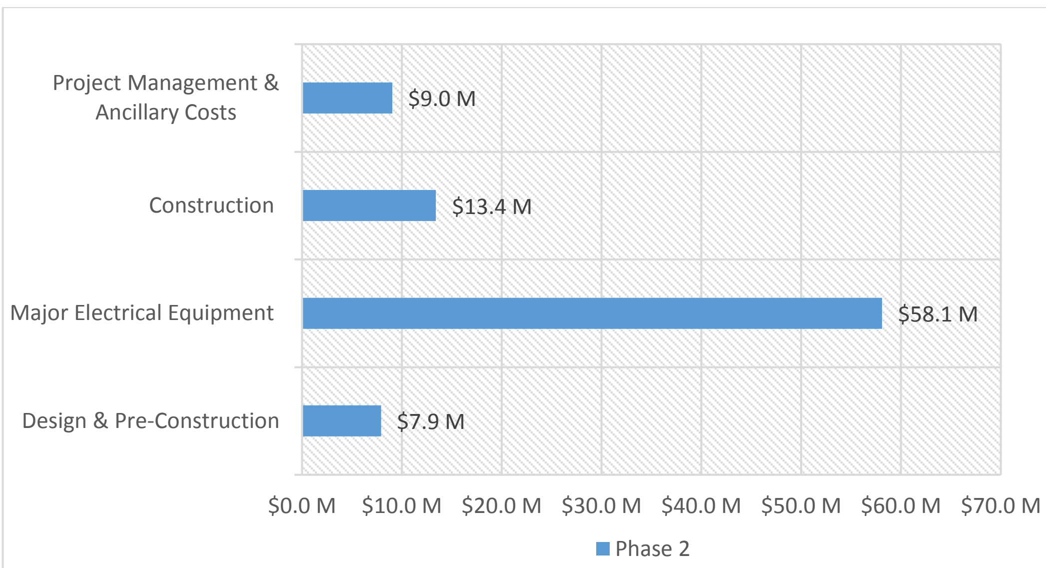

Figure 1: Copeland TS –Phase 2 Cost Breakdown

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**
VOLUME:	**Technical Conference**	
DATE:	**February 19, 2019**	

from left to right, the Hydro One 1 and 2, those were projects undertaken by Hydro One, and the original estimates related to those projects were estimates provided by Hydro One. Is that correct?

MR. LYBEROGIANNIS: Yes, Mr. Gluck.

MR. GLUCK: Thank you. Moving to 2B-Staff-95, part C. This is with respect to the Copeland Phase 1 project. And my first question, I am really just trying to understand the total budget for the project.

Is it correct to say that there was a budget of $143 million for this project during the period prior to 2015, and then 51 million in the 2015 to 2019 period, for a total budget of $195 million?

MR. LYBEROGIANNIS: Mr. Gluck, may I ask you just to repeat that question?

MR. GLUCK: Sure. I am just trying to understand the budget for the project and when the spending was expected to occur. So my understanding from this response is that there was a budget of $143 million for the project that would have been filed in the -- I think you gave me an EB number -- EB-2012-0064.

So there was an expectation that in that proceeding you advised the Board that $143 million would be spent prior to 2015. And then in the 2015 proceeding you advised the Board that $51 million would be spent in the 2015 to 2019 period, for a total budget of $195 million.

MR. LYBEROGIANNIS: Yes, that's correct.

MR. GLUCK: Thank you. Going to table 1, which is on page 4 of the same response, it seems that the capital contribution to Hydro One was -- had a variance of 20.5 million between approved and the current forecast. And when you remove the Hydro One aspect of the project budget, the cost overrun on Toronto Hydro's part of the project is $29.5 million on a $134.6 million project. This is eliminating the Hydro One portion of the project.

Can you explain what happened? Was there a shift of work between Toronto Hydro and Hydro One? Or was it something else?

[Witness panel confers]

MR. LYBEROGIANNIS: Mr. Gluck, the particular table you are referring to is 2B-Staff-95, table 1, I believe.

MR. GLUCK: Yes.

MR. LYBEROGIANNIS: So the response to your question is, yes, there was a reduction capital contribution to Hydro One, and there were, as you can see from the table, there were increases in other elements of the particular project.

MR. GLUCK: Right. Let me ask you this. Basically what I am doing is I'm netting out the capital contribution portion of this project, because that portion is done by another utility. So when I take out the 60.4 from the OEB approved amount, we get down to a $134.6 million project on a forecast basis. Right?

MR. LYBEROGIANNIS: Yes.

MR. GLUCK: And then I pull out the 39.9 million capital contribution that was actually paid on an actual basis, and I take that out from the 204. So now I am comparing the work that Toronto Hydro did on this project. And when you run the numbers, Toronto Hydro spent $29.5 million more on its aspect of the project, which is relative to a 134.6 million total amount, which is a 22 percent increase relative to the forecast.

So my question is, can you explain exactly what happened? What I am trying to ask you, actually, is: Did Toronto Hydro do more work than it expected because Hydro One did less work? Is that the reason for the variance? Or is it cost overruns on Toronto Hydro's side of the project?

MR. TRGACHEF: So the main change in the capital contribution resulted from design change that was developed with Hydro One that Toronto Hydro initiated, where we reduced the amount of high-voltage breakers from initial design of ten to six.

So it was reconfigured to a lower number. However, resulting from those design changes, it did impact other areas of the project where we -- Toronto Hydro did take on more work.

Where I can point you to is, the area of the tunnel work redesign did impact Toronto Hydro and doing additional work or change in scope.

MR. GLUCK: So just to repeat back, it was a change in scope to Toronto Hydro's side of the project, because Hydro One installed less -- did you say transformers?

MR. TRGACHEF: High-voltage switch gear.

MR. GLUCK: High-voltage switch gear. Okay.

Let me take you to Part B of the same response. You reference in that response contractor performance. And you speak to "the general contractors' U.K. parent company entered into compulsory liquidation on January 15, 2018", so you talk about that in that response

My question for you is, were you aware that the contractor was having issues earlier in the process? Or did Toronto Hydro have to react after the fact to that liquidation?

MR. TRGACHEF: If I can direct you to 2B-SEC-68, in response to C we indicate Toronto Hydro's internal enterprise risk management tools that we used to evaluate risk on a project such as Copeland. So this is a risk management model that we use to manage risks throughout the project.

If you turn to the Project Risk Map, the Carillion schedule outlined in A1 and rebased in A2 is a risk we manage throughout the project.

This is -- this is an issue that was reviewed on a monthly basis by the risk committee, and assessed at that point.

MR. GARNER: Mr. Gluck, do you mind if I just ask the question this way: Do you have an estimate of the costs, incremental costs that were incurred by Toronto Hydro due to the failure of the contractor?

MR. TRGACHEF: For that, I will direct you back to 2B Staff 95, and again to table 1. The actual costing that

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 93:

Reference(s): **Exhibit 2B, Section E7.4, p. 1**

Preamble:

The stations expansions program is a continuation of the expansion activities described in Toronto Hydro's 2015-2019 DSP.

a) Please provide a list of the work that was described in Toronto Hydro's 2015-2019 DSP (including the dollar value) that will be completed during the 2020 – 2024 period.

RESPONSE:

a) The following projects described in 2015-2019 DSP (EB-2014-0016) will be completed during the 2020-2024 period (EB-2018-0165):
   - Copeland TS – Phase 2; and
   - Horner TS Expansion.

   Table 1 and Table 2 below show the cost breakdown of these projects as described in Toronto Hydro's 2015-2019 DSP (EB-2014-0116) and as provided in the 2020-2024 DSP (EB-2018-0165).

Table 1: Copeland TS – Phase 2 – Cost Breakdown ($ Millions)

	Copeland TS – Phase 2										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
EB-2014-0116					24.0	22.0					**48.0**
EB-2018-0165			0.5	1.8	7.8	8.9	29.7	38.8	1.0		**88.5**

Note 1: For EB-2018-0165 costs, 2015-2017 are actuals, 2018-2019 are bridge, and 2020-2024 are forecasts.

Table 2: Horner TS Expansion – Cost Breakdown ($ Millions)

	Horner TS Expansion										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
EB-2014-0116		12.0	20.0	20.0	20.0						**72.0**
EB-2018-0165	0.05	0.3	--	15.0	19.4	10.6	7.8	8.0	8.0		**69.15**

Note 1: For EB-2018-0165 costs, 2015-2017 are actuals, 2018-2019 are bridge, and 2020-2024 are forecasts.

The cost variance between EB-2014-0116 and EB-2018-0165 for the Copeland TS – Phase 2 project is described below:

EB-2014-0116

This forecast only included procurement costs for materials, and did not include additional budget costs (including project management, labour, insurance, legal, etc.).

EB-2018-0165

In addition to the point made above, three factors contributed to an increase in forecasted project costs:

1) <u>Project Structure</u>: In Copeland TS – Phase 1, Toronto Hydro used separate contractors for design, supply, and construction. As a result of the Phase 1 experience, a decision was made to use an engineering, procurement, and construction (“EPC”) contract model for Phase 2. This has resulted in significant

increased costs associated with project design, project administration, and management (both for Toronto Hydro and the EPC firm), audit oversight, and billing costs.

2) Lessons Learned: In addition to the updated project structure, other lessons learned during Copeland TS – Phase 1 have increased the costs associated with Copeland TS – Phase 2 (e.g. difficult site conditions, transformer delivery and logistics costs, etc.). These lessons have resulted in additional costs forecasted for Phase 2.

3) Cost Escalation: The most recent forecast provides more realistic cost escalation factors for both material and labour costs, which have been rising sharply in Toronto.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

UNDERTAKING NO. JTC1.18:

Reference(s):

To provide the document referred to during the Copeland Phase 2 approval process.

RESPONSE:

Please see Appendix A to this response. Certain parts of this document have been redacted for confidentiality purposes.

Copeland TS Phase 2 Briefing

September 5, 2017
Tom Odell

The star design is a trade-mark of Toronto Hydro Corporation used under licence. 'Toronto Hydro' means Toronto Hydro-Electric System Limited.

Agenda

- Copeland TS Scope
- Phase 2 OEB Filing History
- Customer Service: Addressing Load Growth & Responsiveness
- Outcomes
- Budget Forecast
- Project Timeline
- Alternatives/Risk
- Conclusion

Copeland Transformer Station Project Scope

Project Purpose

- To facilitate infrastructure rebuild at Windsor TS, to improve supply reliability to downtown area, and to provide capacity and feeder positions for load growth in this area

Phase 1 Scope

- Design, procure, construct, install, test, commission and energize a new transformer station, including site preparation, building and tunnel construction, 115kV interface with HONI incoming circuits, 115/13.8kV transformers, 115 kV and 13.8kV switchgear, and installation of a 600 m cable tunnel between the new transformer station and the existing Front St underground transmission tunnel. Scope also includes the disassembly and reconstruction of the Machine Shop heritage building, and road reconstruction.
- All building structures and attachments are to be seismic
- Large capital contribution for HONI work

Phase 2 Scope

- Additional capacity expansion of Copeland TS (design, procure, construct, install, commission, energize)
- All equipment and attachments are to be seismic

Copeland TS Major Electrical Scope

Phase 1	Phase 2
Major Electrical Equipment to be designed, manufactured, installed, assembled, tested, commissioned and energized: ▪ Six 115 kV High Voltage Switchgears ▪ Two 130/144 (LTR) MVA Transformers ▪ Two 13.8 kV Switchgears ▪ P&C and Metering Equipment ▪ HV/MV/Control Cable Installation & Terminations, Installation/Supports/Racking/Tray	Major Electrical Equipment to be designed, manufactured, installed, assembled, tested, commissioned and energized: ▪ Three 130/144 (LTR) MVA Transformers (T5 spare) ▪ Three 13.8 kV Switchgears ▪ Additional P&C and Metering Equipment ▪ HV/MV/Control Cable Installation & Terminations, Installation/Supports/Racking/Tray

OEB Filing History: Phase 2

- All prior OEB filings cited future phases of Bremner/Copeland with varying levels of detail
- 2012 ICM filing was the first to provide details of Bremner/Copeland Phase 1 with some high-level description of Phase 2 scope
- 2014 EDR filing referenced Phase 2 activities and provided spending and timeline
- Upcoming 2020 filing will be the first one with detailed Phase 2 justification

OEB Filing	Description	Phase 2 Budget
EB-2009-0139 (Ex D1, Tab 7, Sch 1, p17)	Bremner project consists of 72MVA initial phase, with provision for 3 additional phases for 216MVA (3x72)	N/A
EB-2010-0142 (Ex D1, Tab 9, Sch 6)	Same as 2009: 72MVA initial phase, with provision for 3 additional phases for 216MVA (3x72)	N/A
147 EB-2012-0064 (Tab 4, Sch B17, p16-29, 38)	Bremner broken out into two phases, with phase 2 consisting of additional three 13.8kV switchgears and three 144MVA transformers for 144MVA of additional capacity. "Phase 2 of Construction of the Transformer Station (2021) - This involves the installation of additional transformers and medium voltage switchgear within the available space in the Transformer Station to supply additional loads as they increase from 2021 to 2030. This scope of work is not included in the capital costs requested in this filing."	$47.3M (in 2012 dollars) $77M "…needed to expand transformation capacity at Bremner from 2016 to 2030 due to load growth in the downtown core." [Appendix 3, Navigant Business Case Analysis, Apr 2012, p26]
EB-2014-0116 (Ex 2B, Sec E7.9)	Copeland Phase 2 listed with anticipated start date in 2019 and completion in 2020	$ 46M (24M in 2019, 22M future period)
[PROPOSED] Upcoming 2019 filing (for 2020-2025 period)	Copeland Phase 2 details (scope, planned work, schedule, up-to-date budget, phase 1 implications).	$ 88.5M proposed ($78.5M in 2020-2025 period)

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)

Alternatives & Risks

A. Separate Phase 2 Activities into Multiple Phases (T5 (spare), T4, T2)
   - Loss in efficiency and increased cost due to multiple mobilizations/demobilizations, procurements, permitting
   - Risk of customer load/requests materializing faster than anticipated

B. Defer all work to next rate filing (2025-2029)
   - Will not able to serve customer loads in 2027; earliest is possibly 2030
     - Capacity and feeder positions
   - Project team will be dismantled with loss of experience and knowledge
   - T5 deferred: Reliability concerns persist; area contingency option deferred

C. Expand Esplanade
   - Joint THESL-HONI project (dependent on HONI)
   - Longer lead-time; CCRA; stakeholder relations; MV civil
   - Transmission system limitations would prevent Copeland Phase 2 from ever being executed

D. CDM/DG Programs
   - Depends on longer-term government CDM/DG policy and outcome not guaranteed

Conclusion

- Phase 2 enables Toronto Hydro to meet future customer demand in the downtown core, as well as emerging City development plans
- Incorporating proposed development and building permit data, Toronto Hydro analysis indicates a strong need for Copeland Phase 2 by 2027
- In addition to capacity concerns, availability of feeder positions is a growing concern

- Station projects are complex with long project execution timelines and need to be executed well ahead of actual customer connection
- Numerous tangible benefits to customers and THESL including most cost-effective solutions (shorter feeder runs)
- Spare transformer improves system reliability and enables area contingency option

- In consideration of the needs, alternatives and risk, it is proposed Copeland Phase 2 is part of the 2020-2024 CIR Application

APPENDIX

E7.2 Energy Storage Systems

E7.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): $0.5 (Rate Base)	**2020-2024 Cost ($M):** $5.8 (Rate Base)
2015-2019 Cost ($M): $7.9 (Net Costs)	**2020-2024 Cost ($M):** $10.5 (Net Costs)
2015-2019 Cost ($M): $35.2 (Gross Costs)	**2020-2024 Cost ($M):** $52.8 (Gross Costs)
Segments: System Service	
Trigger Driver: Category 1- Power Quality; Category 2- Public Policy	
Outcomes: Customer Service, Reliability, Financial Sustainability, Public Policy	

The Energy Storage Systems ("ESS") program was developed to put batteries to use for the benefit of customers where this non-wires option is the best solution to enable or improve distribution service. As is stated in the 2017 Long-Term Energy Plan, "Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings."[1]

The Long-Term Energy Plan makes reference to two studies on energy storage that were completed at the request of the Ministry of Energy: (i) a 2016 IESO study on energy storage; and (ii) a 2017 study published by Essex Energy Corporation.

The IESO study, "IESO Report: Energy Storage," was produced in response to a request from the Ministry of Energy in April 2015. This study presents the many benefits of energy storage to the bulk electricity system. Among the benefits the report identifies is the deferral of system upgrades through the use of energy storage to reduce local system peaks.[2] The report states:

> *"Energy storage could also help improve the utilization of existing transmission and distribution assets by deferring some costs associated with their upgrades or refurbishments, as well as improve the quality of electricity supply in certain areas of the system by controlling local voltages."*[3]

[1] 2017 Long-Term Energy Plan, Ministry of Energy, 2017, p.60
[2] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.5
[3] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.35

Essex Energy Corporation's 2017 study, "The Study of Energy Storage in Ontario's Distribution Systems," was requested by the Ministry of Energy in March 2016. The report describes a number of benefits of energy storage, including distribution system upgrade avoidance, new generation capacity avoidance, redundant power supply (reliability), and power quality improvement.[4] In one of its case studies, the report also identifies the enablement of renewable generation as another benefit of energy storage.[5]

The IESO's 2015 "Central Toronto Area Integrated Regional Resource Plan" also highlights the benefits of energy storage, particularly as a solution to "community level" energy planning, including opportunities to enable renewable generation.[6]

Battery-based Energy Storage Systems are typically comprised of two components: batteries and power electronics. Batteries absorb and supply energy in direct current ("DC"). Power electronics convert battery DC power to alternating current ("AC") (and vice versa) to enable connection to the distribution system. The power electronics also connect and disconnect the batteries from the distribution system. The ability of the ESS to deliver the expected benefits depends not only on the size of the batteries, but also on the capacity ratings, configuration, and switching capabilities of the associated power electronics.

Toronto Hydro's proposed ESS Program includes three investment segments:

1) Grid Performance ESS,
2) Renewable Enabling ESS, and
3) Customer-Specific ESS

Grid Performance ESS projects utilize battery energy storage as integrated components of the traditional distribution system. These projects benefit multiple customers, in the same way as other distribution infrastructure (e.g. poles, wires, and transformers), and can provide specific solutions to distribution problems. Toronto Hydro proposes to use ESS to achieved grid performance enhancements, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase capacity of a feeder at peak periods. During the 2020-2024 period, $5.5 million is proposed for this category of investment.

[4] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p12
[5] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p27
[6] Central Toronto Area Integrated Regional Resource Plan, Independent Electricity System Operatior, 2015, p90

ESS systems can provide other distribution benefits including local demand response (DR). A local DR solution is being implemented at Cecil TS in the 2015-2019 rate period and is proposed for expansion during the 2020-2024 rate period as described in Section E7.4.

Toronto Hydro is proposing to use ESS connected to the distribution system along the feeder segments where customers would benefit from enhanced grid performance. These needs are diagnosed on a feeder-by-feeder basis having regard to the performance of that part of the grid with respect to capacity, reliability, power quality, and other relevant measures. Where a traditional poles and wires approach is applicable, the solution might be to upgrade the feeder, re-orient feeders, install additional protection and control devices, or undertake other conventional investments. In other instances, a poles and wires option may not be available for a variety of technical or economic reasons. This program will enable Toronto Hydro to pursue ESS options, as may be optimal in a given situation.

A typical example of where a battery solution can be used to cost-effectively improve grid performance would be an area with a relatively high concentration of customers who are sensitive to power quality disturbances. Benefits of such a solution include the following:

- **Voltage Sags:** ESS can offset significant voltage sags and provide ride-through capability.
- **Voltage Support:** ESS can dynamically counteract voltage fluctuations through voltage regulation, thereby minimizing the voltage fluctuations that adversely affect customer equipment and processes.
- **Phase balancing/efficiency**: ESS can help rebalance feeders that exceed the threshold for single phase imbalances, thus decreasing the return current on the neutral conductor and reducing line losses.
- **Reliability and power quality improvements**: ESS can improve the overall power quality for customers by counteracting variations in voltage and harmonics, as well as the effects of switching.

Renewable Enabling ESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. Distributed renewable generation has been supported in Ontario for over a decade through a series of programs offered through the Ontario Power Authority and IESO, including FIT, microFIT, and Net Metering. Customers who do not have contracts through these programs also install renewable generation. Those customers can receive payments according to hourly market prices or, more often, offset their monthly bill by generating their own electricity behind the meter.

As is the case with other renewable enabling improvements ("REI"), projects in this investment segment are funded 6 percent in the LDC rate base and 94 percent through the provincial REI revenue stream. Over the 2020-2024 period, $5 million is proposed for this segment, with $0.3 million (6 percent) allocated to Toronto Hydro's rate base. These investments are expected to enable the aggregate connection of 5 MW of renewable projects, which would otherwise not be possible due to technical limitations of the grid.

Similarly, ESS can cost-effectively enable electric vehicles ("EVs") to connect to the distribution system by addressing localized system constraints. Toronto Hydro is not proposing any EV ESS projects at this time.

Customer-Specific ESS projects would be installed at the request of the customer, typically behind the customer meter in order to maximize the benefits of the investment. These projects improve traditional distribution service outcomes such as power quality and reliability. By locating these distribution assets behind the meter, they also provide the customer with financial benefits, such as hourly peak-shaving and Industrial Conservation Initiative ("ICI") benefits (i.e. Global Adjustment relief for Class A customers who reduce their demand during provincial peak periods). Thus, the customer-specific behind the meter benefits "stack on top" of the distribution benefits, thereby creating a greater set of benefits associated with the ESS project.

Over the 2020-2024 period, $42.3 million is proposed for this segment. Investments in this segment are driven by the requesting customer's needs. In accordance with the "beneficiary pays" principle, Toronto Hydro will therefore hold these host site customers directly responsible for the costs of the projects that benefit them. As with other capital contributions, payments from the host site customers will offset the amounts that are added to rate base and charged through rates to all ratepayers. Presumptively, the result is that 100 percent of the $42.3 million of planned expenditures are offset by planned capital contributions, such that the net effect of this segment to the Toronto Hydro rate base is $0.

An example of this type of a Customer-Specific ESS project is the Metrolinx Eglinton Crosstown LRT ESS currently underway in 2018/2019. At its request, Metrolinx will receive reliability and emergency services in the event that distribution service from feeders becomes unavailable. The costs of the project are fully allocated to Metrolinx and recoverable through a capital contribution.

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.