Toronto Hydro-Electric System Limited

EB-2014-0116

Panel 1

Distribution Capital & System Maintenance

AMPCO Compendium

February 17, 2015

4. SUMMARY OF KEY DETAILS OF THE APPLICATION

4.1 Capital Expenditures And Rate Base

4.1.1 Capital Expenditures

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

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

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

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

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

	2016	2017	2018	2019
Capital Expenditures	518.8	467.4	470.0	502.2

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

Capital Investment Drivers

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

[17] EB-2010-0142

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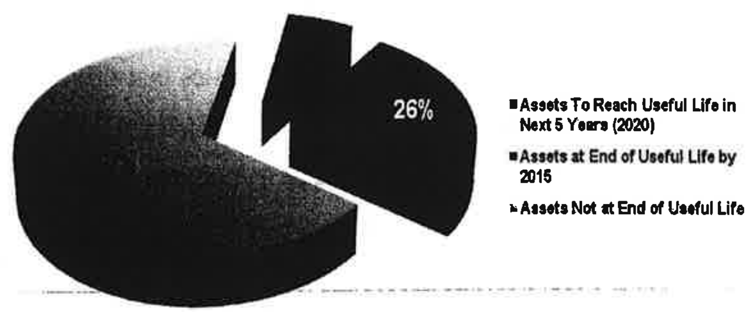
including a secondary network system, is unique in its span and configuration in Ontario's distribution sector.

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



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

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

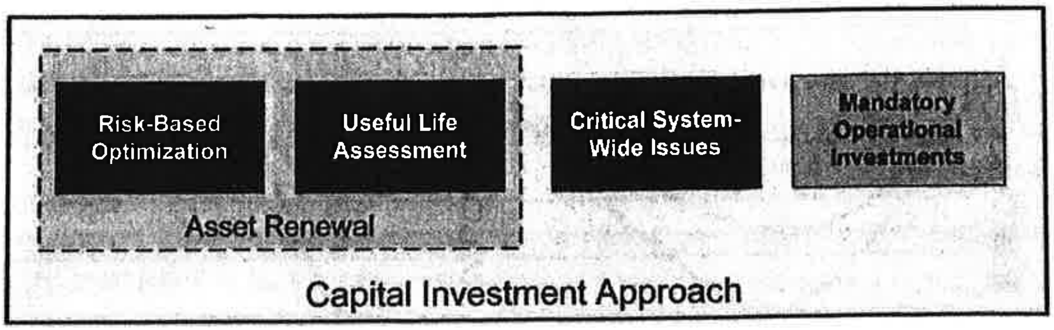


FIGURE 3: CAPITAL INVESTMENT APPROACH (2015-2019)

(a) **Asset Renewal:** To achieve steady state, in-kind replacement must be performed for those assets reaching or exceeding their economic end-of-life criteria. The Feeder Investment Model can be applied as to identify the economic end-of-life criteria and investment timing for all evaluated assets as per a risk-based optimization approach. For those asset classes not evaluated by the FIM, asset investment timing was determined based upon the assets' remaining useful life.

(b) **Critical System-Wide Issues:** This area of investment includes those broader investments of the utmost urgency, designed to target issues that go "beyond the asset", such as load growth, capacity and contingency constraints, operational flexibility and accessibility, safety and security of supply issues.

(c) **Mandatory Operational Investments:** This area of investment includes those necessary and mandatory day-to-day investments that support the 24/7 operations of Toronto Hydro, including customer-service requests, mandated service obligations, capital and maintenance support and non-system physical plant investments associated with Information Technology, Fleet and Facilities.

The spending requirements produced by this capital investment approach, illustrated in Figure 4, reveal a substantial investment backlog of approximately $2.56 billion that would optimally be /C
spent in 2015, followed by approximately $1.55 billion in investment from 2016 through 2019 (in aggregate). The backlog is comprised predominantly of assets that are past their economic end-of-life and end-of-useful life respectively, as well as critical issues that must be urgently addressed. This backlog exposes Toronto Hydro's distribution system to immediate risks.

Toronto Hydro's assessment is that the spending requirements reflected are ultimately representative of an economically optimal capital investment approach: execution of these investments would mitigate this backlog and allow for an immediate achievement of steady state. This approach would minimize the operating costs to which customers are exposed when considering capital and risk costs.

However, Toronto Hydro recognizes that executing a capital investment approach of this magnitude in a single year would constitute an unprecedented level of investment, and would result in large step-increases in rates. Moreover, the utility could not reasonably expect to execute this magnitude of investment in a single year considering current system constraints and available resources.

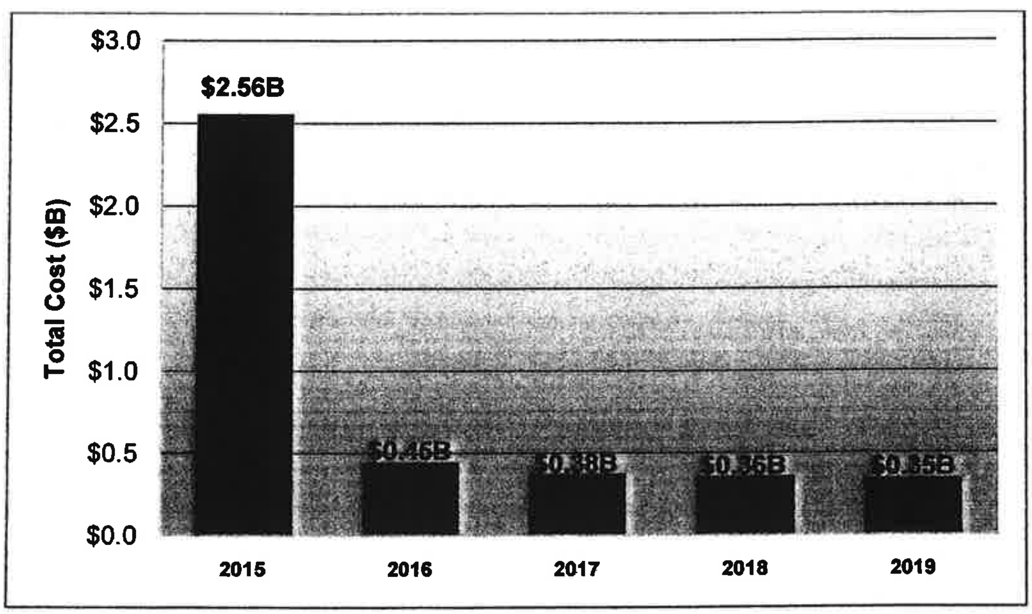


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FIGURE 4: ECONOMICALLY OPTIMAL CAPITAL INVESTMENT APPROACH (2015-2019)

Recognizing the infeasibility of completing this work in a single year, Toronto Hydro considered two alternative timelines in which to carry out this work: an "accelerated" strategy as well as the proposed "paced" strategy. The accelerated strategy would allow for the backlog of investments to be managed over the five-year DSP period, such that steady state is achieved by 2019 with a

(i) "Accelerated" Execution Strategy

The "accelerated" execution strategy is focused on mitigating the backlog of investments within the 5-year DSP period, such that steady state is achieved by 2020.

As illustrated in Figure 10, this strategy requires significant capital investments of approximately $830 million on average per year, with a total five-year investment of $4.17 billion. The advantage of this strategy is that steady state can be achieved in more rapidly, therefore mitigating the risks associated with the backlog within the five-year period. However, it is clear that the rate impacts from this strategy would be substantial for customers. Furthermore, the required investments do not align to Toronto Hydro's available resources and system constraints, and therefore there would likely be execution-related complexities.

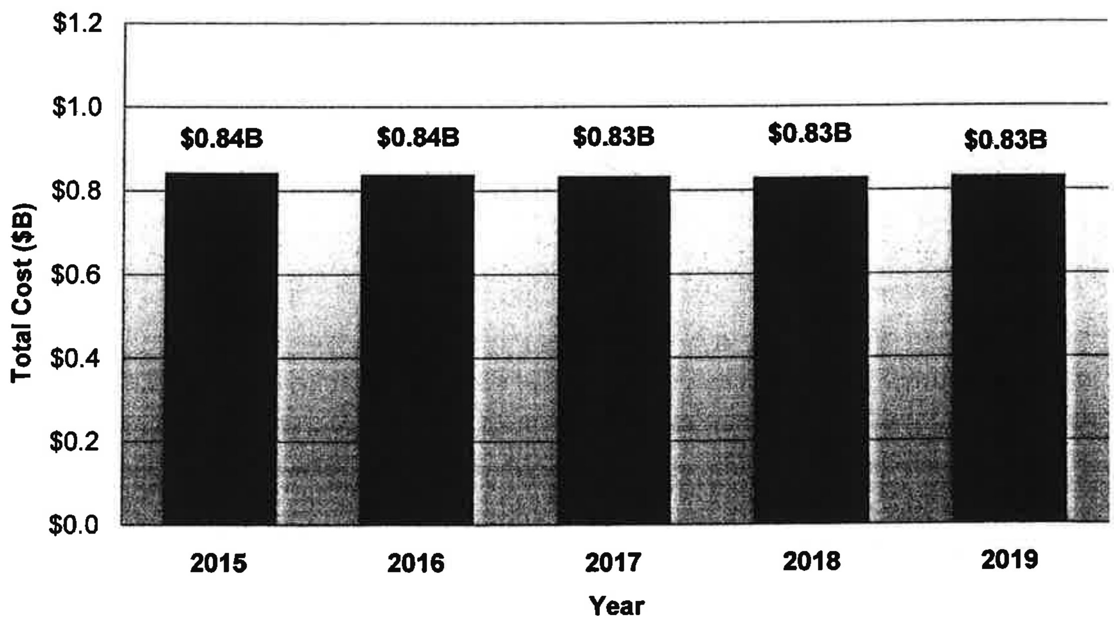

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FIGURE 10: CAPITAL INVESTMENT APPROACH AS PER "ACCELERATED" EXECUTION STRATEGY

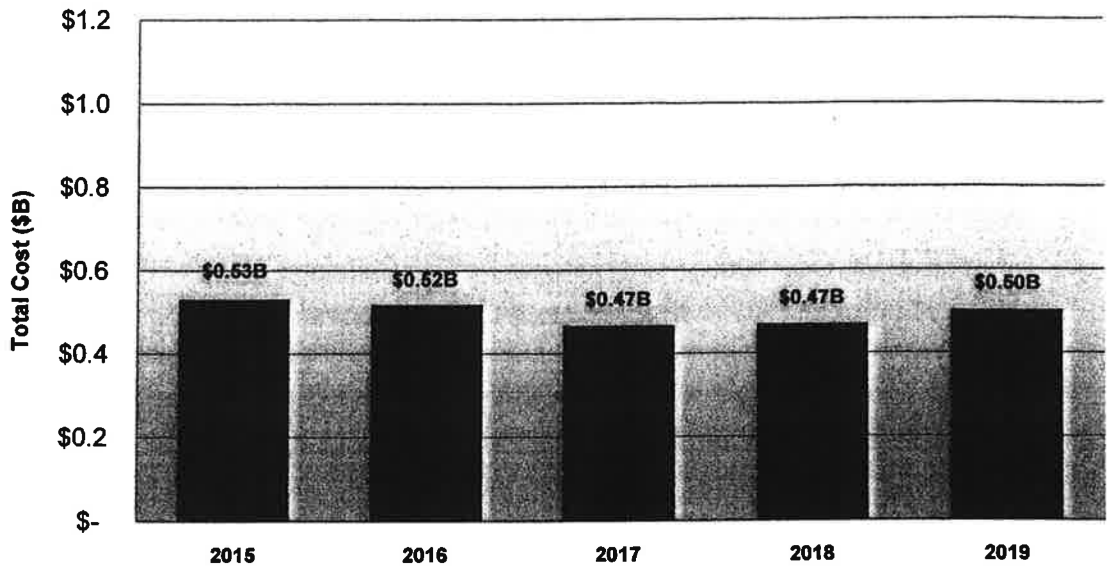

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FIGURE 11: CAPITAL INVESTMENT APPROACH AS PER "PACED" EXECUTION STRATEGY (2015-2019)

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

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

OEB Appendix 2-AA
Capital Projects Table

Projects	2010	2011	2012	2013	2014 BRIDGE	2015 TEST	2016 TEST	2017 TEST	2018 TEST	2019 TEST
Reporting Basis	CGAAP	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Metering	28.4	22.1	12.1	12.2	14.0	24.7	16.6	14.7	11.7	13.7
Customer Connections	15.2	31.2	31.0	53.4	52.1	39.3	53.8	64.9	56.9	46.6
Externally-Initiated Plant Relocation & Expansion	0.7	5.0	9.8	18.6	8.8	4.0	4.0	4.0	4.0	4.0
Load Demand	-	-	0.3	2.4	1.1	12.0	13.9	14.0	15.7	19.2
Generation Projects Protection and Control	-	-	-	-	-	6.1	5.2	3.3	2.1	2.0
System Access Investments Sub-total	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
Underground Circuit Renewal	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5
Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	-	5.5	1.5	2.4	4.7	3.5	1.4	0.7	0.8	0.5
Underground Legacy Infrastructure	-	-	-	-	-	2.1	6.7	6.6	6.5	5.5
Overhead Circuit Renewal	25.8	28.3	23.2	49.0	53.3	44.0	23.0	24.9	25.3	30.3
Overhead Infrastructure Relocation	-	-	-	-	-	0.7	1.4	1.8	2.3	3.6
Rear Lot Conversion	6.9	16.6	17.5	23.8	22.7	17.0	8.1	10.3	10.3	13.6
Box Construction Conversion	5.7	7.1	0.8	13.8	23.3	16.8	20.7	21.1	21.6	22.7
SCADAMATE R1 Renewal	-	-	-	1.9	2.6	6.2	4.1	2.7	-	-
Network Vault Renewal	1.7	0.9	3.6	10.8	0.9	4.0	10.4	10.3	10.3	10.2
Network Unit Renewal	7.3	4.4	5.1	7.3	3.6	5.2	7.4	7.3	7.3	7.3
Legacy Network Equipment Renewal (ATS & RPB)	0.4	0.0	0.1	1.6	0.2	0.4	1.0	1.1	0.9	1.1
Network Circuit Reconfiguration	-	-	-	-	-	-	2.3	2.3	2.3	2.3
Stations Switchgear Renewal	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4
Stations Power Transformer Renewal	1.8	4.0	2.7	1.7	1.3	1.7	2.6	2.6	2.7	2.7
Stations Circuit Breaker Renewal	0.0	0.9	0.2	1.0	2.1	1.7	1.8	1.8	2.1	1.8
Stations Control & Monitoring	-	-	0.1	0.5	0.2	0.1	0.9	1.1	1.5	1.4
Stations Ancillary Systems	0.1	0.1	0.2	0.6	0.2	0.7	0.6	0.4	0.3	0.4
Station Buildings	-	-	0.5	0.0	0.2	0.5	2.5	2.3	2.6	3.3
Stations DC Battery Renewal	0.2	0.2	0.4	0.3	0.6	0.3	0.7	0.7	0.7	0.7
Reactive Capital	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2
Worst Performing Feeder	16.7	19.3	6.7	1.2	4.8	1.2	1.8	1.8	1.8	1.8
Telecom Program	-	-	-	1.0	0.9	6.1	6.0	4.0	-	[illegible]
System Renewal Investments Sub-Total	215.0	215.3	157.2	231.1	286.3	251.7	235.0	246.3	260.4	[illegible]
Contingency Enhancement	-	-	-	-	-	10.0	5.9	9.7	9.7	15.3
Design Enhancements	-	-	-	-	-	0.4	1.7	1.7	1.7	1.7
Feeder Automation	3.3	0.9	6.2	8.8	0.8	11.1	15.1	9.4	10.0	8.5
Overhead Momentary Reduction	-	-	-	-	-	-	-	0.6	0.6	0.6
Handwell Upgrades	21.1	32.9	12.6	11.7	16.2	5.0	-	-	-	-
Polymer SMD-20 Renewal	-	-	-	0.8	2.8	4.8	-	-	-	-
Downtown Contingency	1.1	4.7	0.1	1.1	1.0	-	0.7	0.7	1.0	0.9
Customer Owned Station Protection	-	-	-	-	-	0.6	1.0	1.0	0.8	0.6
Stations Expansion	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0
Energy Storage Systems	-	-	-	-	1.0	0.5	1.1	2.2	3.2	3.8
Local Demand Response	-	-	-	-	-	0.2	2.4	0.6	0.5	0.3
Grid Intelligence	3.0	4.8	0.8	0.1	-	-	-	-	-	-
EV	-	-	0.0	0.0	-	-	-	-	-	-
System Service Investments Sub-Total	35.4	75.8	38.4	83.7	101.3	76.5	69.6	62.5	49.5	75.7
Fleet and Equipment Services	10.6	11.8	0.8	2.2	2.6	3.9	3.2	3.7	3.5	3.6
Facilities	12.1	25.3	6.6	14.5	90.3	53.8	24.2	2.0	2.0	1.9
IT Hardware	10.6	9.4	7.4	6.0	5.2	5.9	8.0	7.4	9.8	5.6
IT Software	22.2	21.2	14.5	9.6	10.1	15.5	16.2	15.8	16.8	16.8
Radio Project	-	-	-	-	-	6.7	13.7	-	-	-
ERP*	-	-	-	1.5	0.9	17.7	33.6	-	-	-
Program Support	-	-	-	-	0.4	1.2	0.5	-	-	-
General Plant Investments Sub-Total	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Miscellaneous	12.3	(4.2)	4.5	5.4	3.2	0.9	1.2	1.2	1.2	1.2
AFUDC	3.5	5.2	2.3	3.3	6.5	8.0	5.8	4.5	4.6	4.6
Roadcuts	-	-	3.1	1.8	3.0	3.3	4.1	4.1	4.1	4.1
EAR	34.5	23.6	-	-	-	-	-	-	-	-
Inflation	-	-	-	-	-	-	10.2	18.9	28.0	39.5
Other Sub-Total	50.4	24.6	9.9	10.5	12.7	12.2	21.2	28.6	37.9	49.4
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**531.1**	**518.8**	**467.4**	**470.0**	**502.2**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-	-	(6.3)	(5.9)	(5.1)	(5.0)	(5.4)
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**524.9**	**512.9**	**462.3**	**465.0**	**496.7**

THESL EB-2014-0116 1A-BOMA-8 (b) (d) (e) EB-2007-0680 Decision Page 13

THESL CAPEX - Historical Spending

	2006	2007	2008	2009	2010	2011	2012	2013	2014 Forecast		2014 Actual	2006-2009 Average	2008-2010 Average	2007-2009 Average	2009-2013 Average	2010-2013 Average	2010-2014 Average	2012-2014 Average
Board Approved			271.3	276.7	350.0	378.8	203.3	484.2	71.6	Phase 1			898.0		1693.0	1416.3	1815.1	1086.3
									327.2	Phase 2			**299.3**		**338.6**	**354.1**	**363.0**	**362.1**
									398.8									
Actual	193.0	276.0	234.0	262.0	400.6	445.5	288.0	445.7	589.2			965.0	896.6	772.0	1841.8	1579.8	2169.0	1322.9
												241.3	**298.9**	**257.3**	**460.5**	**395.0**	**433.8**	**441.0**
Variance $															148.8	163.5	353.9	236.6
Variance %															108.8%	111.5%	119.5%	121.8%
Actual vs Board Approved					50.6	66.7	84.7	-38.5	190.4	353.9								

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 5:

Reference(s): **Exhibit 1B, Tab 2, Schedule 4, p.6**

Please revise Figure 1 to show 2012 and 2013 actual, and 2014 current forecast, as separate bars.

RESPONSE:

Figure 1 has been revised to include 2012 and 2013 actual, and 2014 current forecast.

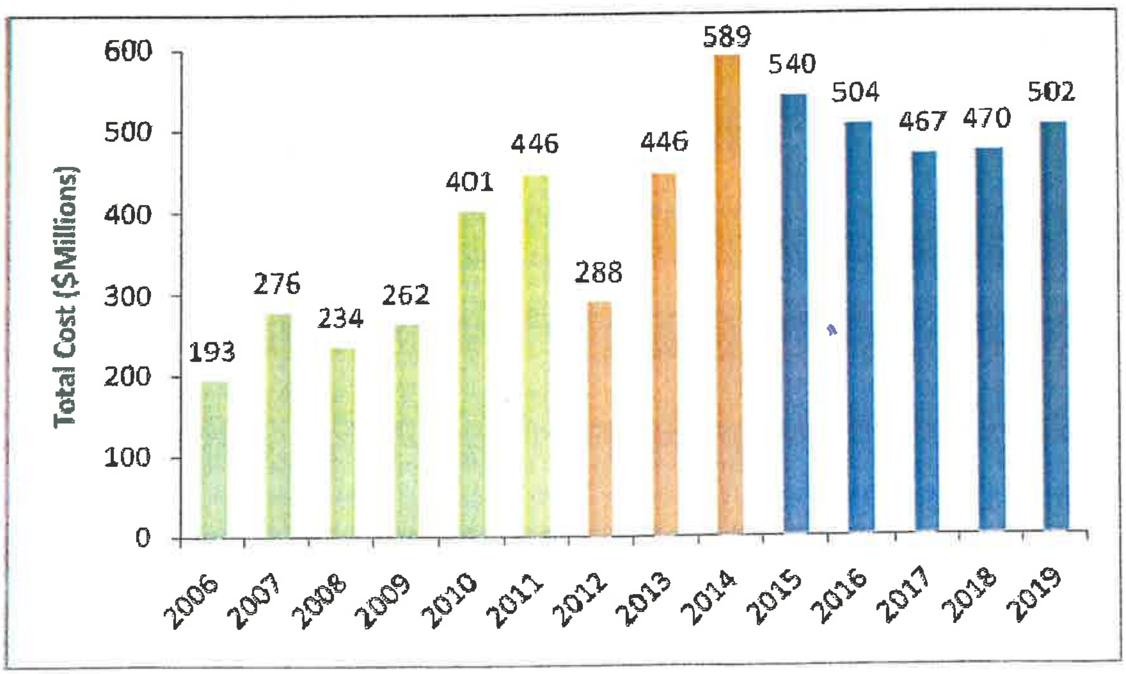

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Table 1: As Filed

	Projects	2010	2011	2012	2013	2014 BRIDGE	2015 TEST	2016 TEST	2017 TEST	2018 TEST	2019 TEST	Total 2010-2014	Total 2015-2019	AVG 2010-2014	AVG 2015-2019	Variance Absolute	Variance Percent
	Reporting Basis	CGAAP	CGAAP	USGAAP	USGAAP	USGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS						
	Metering	28.4	22.1	12.1	12.2	14.0	24.7	16.6	14.7	11.7	13.7	88.8	81.4	17.8	16.3	-1.48	-8%
✓	Customer Connections	15.2	31.2	31.0	53.4	52.1	39.3	53.8	64.9	56.9	46.6	182.9	261.5	36.6	52.3	15.72	43%
	Externally-Initiated Plant Relocation	0.7	5.0	9.8	18.6	8.8	4.0	4.0	4.0	4.0	4.0	42.9	20.0	8.6	4.0	-4.58	-53%
✓	Load Demand	-	-	0.3	2.4	1.1	12.0	13.9	14.0	15.7	19.2	3.8	74.8	0.8	15.0	14.20	1868%
N	Generation Projects Protection and	-	-	-	-	-	6.1	5.2	3.3	2.1	2.0	-	18.7	-	3.7	3.74	0%
	System Access Investments Sub	**44.4**	**58.3**	**53.2**	**86.6**	**76.0**	**86.1**	**93.8**	**100.9**	**90.4**	**86.5**	318.5	456.4	63.7	91.3	27.58	43%
✓	Underground Circuit Renewal	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5	429.4	459.3	85.9	91.9	5.98	7%
	Paper-Insulated Lead-Covered (PIL	-	5.5	1.5	2.4	4.7	3.5	1.4	0.7	0.8	0.5	14.1	6.9	2.8	1.4	-1.44	-51%
N	Underground Legacy Infrastructure	-	-	-	-	-	2.1	6.7	6.6	6.5	5.5	-	27.4	-	5.5	5.48	0%
	Overhead Circuit Renewal	25.8	28.3	23.2	49.0	53.3	44.0	23.0	24.9	25.3	30.3	179.6	147.5	35.9	29.5	-6.42	-18%
N	Overhead Infrastructure Relocation	-	-	-	-	-	0.7	1.4	1.8	2.3	3.6	-	9.8	-	2.0	1.96	
	Rear Lot Conversion	6.9	16.6	17.5	23.8	22.7	17.0	8.1	10.3	10.3	13.6	87.5	59.3	17.5	11.9	-5.64	-32%
✓	Box Construction Conversion	5.7	7.1	0.8	13.8	23.3	16.8	20.7	21.1	21.6	22.7	50.7	102.9	10.1	20.6	10.44	103%
✓	SCADAMATE R1 Renewal	-	-	-	1.9	2.6	6.2	4.1	2.7	-	-	4.5	13.0	0.9	2.6	1.70	189%
✓	Network Vault Renewal	1.7	0.9	3.6	10.8	0.9	4.0	10.4	10.3	10.3	10.2	17.9	45.2	3.6	9.0	5.46	153%
✓	Network Unit Renewal	7.3	4.4	5.1	7.3	3.6	5.2	7.4	7.3	7.3	7.3	27.7	34.5	5.5	6.9	1.36	25%
✓	Legacy Network Equipment Renew	0.4	-	0.1	1.6	0.2	0.4	1.0	1.1	0.9	1.1	2.3	4.5	0.5	0.9	0.44	96%
N	Network Circuit Reconfiguration	-	-	-	-	-	-	2.3	2.3	2.3	2.3	-	9.2	-	1.8	1.84	
✓	Stations Switchgear Renewal	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4	71.9	106.3	14.4	21.3	6.88	48%
✓	Stations Power Transformer Renew	1.8	4.0	2.7	1.7	1.3	1.7	2.6	2.6	2.7	2.7	11.5	12.3	2.3	2.5	0.16	7%
✓	Stations Circuit Breaker Renewal	-	0.9	0.2	1.0	2.1	1.7	1.8	1.8	2.1	1.8	4.2	9.2	0.8	1.8	1.00	119%
✓	Stations Control & Monitoring	-	-	0.1	0.5	0.2	0.1	0.9	1.1	1.5	1.4	0.8	5.0	0.2	1.0	0.84	525%
✓	Stations Ancillary Systems	0.1	0.1	0.2	0.6	0.2	0.7	0.6	0.4	0.3	0.4	1.2	2.4	0.2	0.5	0.24	100%
✓	Station Buildings	-	-	0.5	-	0.2	0.5	2.5	2.3	2.6	3.3	0.7	11.2	0.1	2.2	2.10	1500%
✓	Stations DC Battery Renewal	0.2	0.2	0.4	0.3	0.6	0.3	0.7	0.7	0.7	0.7	1.7	3.1	0.3	0.6	0.28	82%
✓	Reactive Capital	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2	152.4	165.5	30.5	33.1	2.62	9%
	Worst Performing Feeder	16.7	19.3	6.7	1.2	4.8	1.2	1.8	1.8	1.8	1.8	48.7	8.4	9.7	1.7	-8.06	-83%
✓	Telecom Program	-	-	-	1.0	0.9	6.1	6.0	4.0	-	-	1.9	16.1	0.4	3.2	2.84	247%
	System Renewal Investments Su	**215.0**	**219.3**	**157.2**	**231.1**	**286.4**	**251.7**	**236.0**	**246.3**	**260.1**	**265.5**	1,109.0	1,258.6	221.8	251.7	29.92	13%
N	Contingency Enhancement	-	-	-	-	-	10.0	5.9	9.7	9.7	13.5	-	48.8	-	9.8	9.76	
N	Design Enhancements	-	-	-	-	-	0.4	1.7	1.7	1.7	1.7	-	7.2	-	1.4	1.44	
✓	Feeder Automation	3.3	0.9	6.2	8.8	0.8	11.1	15.1	9.4	10.0	8.5	20.0	54.1	4.0	10.8	6.82	171%
N	Overhead Momentary Reduction	-	-	-	-	-	-	-	0.6	0.6	0.6	-	1.8	-	0.4	0.36	
	Handwell Upgrades	21.1	32.9	12.6	11.7	16.2	5.0	-	-	-	-	94.5	5.0	18.9	1.0	-17.90	-95%
✓	Polymer SMD-20 Renewal	-	-	-	0.8	2.8	4.8	-	-	-	-	3.6	4.8	0.7	1.0	0.24	35%
	Downtown Contingency	1.1	4.7	0.1	1.1	1.0	-	0.7	0.7	1.0	0.9	8.0	3.3	1.6	0.7	-0.94	-59%
N	Customer Owned Station Protection	-	-	-	-	-	0.6	1.0	1.0	0.8	0.6	-	4.0	-	0.8	0.80	
	Stations Expansion	6.9	32.5	18.6	61.2	82.2	54.2	28.5	36.5	22.0	44.0	201.4	185.2	40.3	37.0	-3.24	-8%
✓	Energy Storage Systems	-	-	-	-	1.0	0.5	1.1	2.2	3.2	3.8	1.0	10.8	0.2	2.2	1.96	980%
N	Local Demand Response	-	-	-	-	-	0.2	2.4	0.6	0.5	0.3	-	4.0	-	0.8	0.80	
X	Grid Intelligence	3.0	4.8	0.8	0.1	-	-	-	-	-	-	8.7	-	1.7	-	-1.74	-100%
X	EV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	System Service Investments Sub	**35.3**	**75.6**	**38.4**	**83.7**	**104.1**	**86.8**	**56.8**	**62.5**	**49.5**	**73.9**	337.1	329.2	67.4	65.8	-1.58	-2%
	Fleet and Equipment Services	10.6	11.8	0.8	2.2	2.6	3.9	3.2	3.7	3.5	3.6	28.0	17.9	5.6	3.6	-2.02	-36%
	Facilities	12.1	25.3	6.6	14.5	90.3	53.8	24.2	2.0	2.0	1.9	148.8	83.9	29.8	16.8	-12.98	-44%
	IT Hardware	10.6	9.4	7.4	6.0	5.2	5.9	8.0	7.4	9.8	5.6	38.6	36.7	7.7	7.3	-0.38	-5%
✓	IT Software	22.2	21.2	14.5	9.6	10.1	15.5	16.2	15.8	16.8	16.8	77.6	81.1	15.5	16.2	0.70	5%
N	Radio Project	-	-	-	-	-	6.7	13.7	-	-	-	-	20.4	-	4.1	4.08	
✓	ERP*	-	-	-	1.5	0.9	17.7	33.6	-	-	-	2.4	51.3	0.5	10.3	9.78	2038%
✓	Program Support	-	-	-	-	0.4	1.2	0.5	-	-	-	0.4	1.7	0.1	0.3	0.26	325%
	General Plant Investments Sub-T	**55.5**	**67.7**	**29.3**	**33.8**	**109.6**	**104.6**	**99.4**	**28.9**	**32.1**	**27.9**	295.8	292.9	59.2	58.6	-0.58	-1%
	Miscellaneous	12.3	-4.2	4.5	5.4	3.2	0.9	1.2	1.2	1.2	1.2	21.2	5.7	4.2	1.1	-3.10	-73%
✓	AFUDC	3.5	5.2	2.3	3.3	7.1	6.1	4.3	4.5	4.6	4.6	21.4	24.1	4.3	4.8	0.54	13%
✓	Roadcuts	-	-	3.1	1.8	3.0	3.3	4.1	4.1	4.1	4.1	7.9	19.7	1.6	3.9	2.36	149%
X	EAR	34.5	23.6	-	-	-	-	-	-	-	-	58.1	-	11.6	-	-11.62	-100%
N	Inflation	-	-	-	-	-	-	10.2	18.9	28.0	39.5	-	96.6	-	19.3	19.32	
	Other Sub-Total	**50.4**	**24.6**	**9.9**	**10.6**	**13.3**	**10.3**	**19.8**	**28.8**	**37.9**	**49.4**	108.7	146.0	21.7	29.2	7.46	34%
	Total	**400.6**	**445.5**	**288.0**	**445.7**	**589.2**	**539.6**	**504.2**	**467.4**	**470.0**	**502.2**	2,169.0	2,483.4	433.8	496.7	62.88	14%
	Less Renewable Generation Faci	-	-	-	-	-	-6.3	-5.9	-5.1	-5.0	-5.4	-	-27.7	-	-5.5	-5.54	
	Total	**400.6**	**445.5**	**288.0**	**445.7**	**589.2**	**533.4**	**498.3**	**462.3**	**465.0**	**496.7**	2,169.0	2,455.7	433.8	491.1	57.34	13%

✓ Spending Increasing
N New Program
X No Spending

2015 to 2019 Total $ 2,483.4
2015 to 2019 Average $ 496.7

b) Publication Information

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

c) Summary of Bill Impacts

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

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

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

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Ontario Energy Board

Ontario

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

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pacing and prioritization of investment in a manner that controls year-over-year rate increases and to reducing the need for mitigation at the time of Board approval. Others noted that some costs on the total bill are outside of a distributor's control, and that increases in these costs should not result in automatic offsetting adjustments to distribution investment spending.

The Board's Conclusions

As indicated in the Introduction to this Report, the Board's first two statutory objectives are key considerations for the policies described in this Chapter. Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan. The Board recognizes that factors beyond a distributor's control may add complexity and uncertainty to any effort to estimate bill impacts on customers. However, a distributor must exercise control over the pace of its own capital spending, as this factor can be an important element in the total cost of electricity to customers. To aid distributors in this essential task, standardized methods and tools should be developed for use by distributors in the preparation of their plans. In addition, the Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor).

The Board will further engage stakeholders on the identification and development of qualitative and quantitative approaches and tools to be used by distributors to support their investment proposals, including methodologies to assist in prioritizing and pacing proposed investments in consideration of the total bill impact on customers. The output of any methodology will need to be transparent, robust and reproducible, and include forecast information from independent and authoritative sources where these are publicly available.

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1 **Table 1: Summary of Asset Condition**

Asset Group	Asset Condition					Total Population	EOL within 10 years Units (%)
	Very Good	Good	Fair	Poor	Very Poor		
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1,732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7,490	2,140	1,070	30,709	10,700 (35%)
Submersible Transformers	3,095	3,094	1,470	420	210	8,289	2,100 (25%)
Vault Transformers	7,178	3,900	1,330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4,950	4,950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6,388	3,194	159,700	31,940 (20%)
Overhead Switches - Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches - Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable - XLPE in Ducts	N/A	2,497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable - PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable - XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4,985	4,985	71	20	10	10,071	101 (1%)

2007-2016

2 Note: N/A indicates no data was available

7) Analyze the asset condition and performance information to identify population condition, performance trends and high risks and impacts of asset condition on meeting business objectives, including service quality standards.
8) Verify and confirm that the asset condition assessment results reflect actual field condition ("spot audits").

RESULTS

The findings of Kinectrics' review of asset condition at THESL are detailed in the report entitled "Distribution Asset Condition Assessment for Toronto Hydro-Electric System Limited, Report K-012905-RA-002-R00", which is attached to this schedule.

In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in the report, in general, Kinectrics found that the available records of assets provided by THESL accurately reflected the condition of the equipment in service.

In the case of a few specific assets classes at THESL, there are indications that assets may be deteriorating faster than they are being replaced and these require actions beyond routine maintenance. Indications of this include the increasing failure rates and the poor Health Indices of some classes of asset. For example, direct buried underground cable is a major asset class that suffers from this deterioration.

The prime results of the condition assessment for each asset class, based on existing condition data, are shown in the following Table 1. This is an ultimate best estimate of the condition of each asset class determined using the Health Index method, or the age-based method where sufficient condition data was not yet available at THESL. The percentage of the total population for each asset class in each condition category, "very good", "good", "fair", "poor", and "very poor", is shown in the "Asset Condition" column. The results show that most assets are in very good or good condition. This indicates in general that the maintenance and capital replacement programs at THESL have been well designed and executed.

The final column on the right hand side indicates the number of assets that are expected to require replacement within the next ten years and the percentage of the total asset class that this represents. It is recommended that the assets in "very poor" condition be planned for replacement in two to three years, and assets in "fair" condition be planned for replacement in four to ten years. It is anticipated that the assets now in "fair" condition will be in "very poor" condition by the end of the ten years.

The assets that require the most significant replacement programs in the next 10 years are:

- Direct buried underground cable (61% of the population)
- Automatic transfer switches (63%)
- Station transformers (50%).
- Pole mounted transformers (35%)
- Network transformer/protector units (32%)

Of the list above, the assets with the largest impact on reliability and cost are the direct buried underground cable and the station transformers. A risk assessment was performed in the context of a larger prioritization of all assets. The final method and recommended plan are detailed in the 2007-2016 Electrical Distribution Plan, filed at Exhibit D1, Tab 8, Schedule 10 of this Application.

A field audit of asset condition was conducted to confirm the results of the asset condition assessment based on existing information. A comparison of the average condition determined by the audit with the average condition based on existing condition data is shown in the bar chart of Figure ES-1. The field audit verified the Health Index results for most assets. Some differences are expected between the two methods of assessing asset condition due to the different condition criteria used in the two methods. The Health Index method is considered to be more accurate in cases where condition data existed in adequate quantity and quality. All equipment was found to be in "good" condition on average, except for underground cables where the Health Index method indicated only "fair" condition on average.

The asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data

Table 1 Unit replacement forecasts using age-based model

Asset Classes	Units in each year 2007-2016	Total	TOTAL POPULATION	%
Station Transformers	15	147	287	51.2
Circuit Breakers	63	632	1,732	36.5
Switchgear Assemblies	7	71	272	26.1
Buildings	0	0		
Network trans/protectors	83	826	2,055	40.2
Submersible Transformers	221	2,209	8,289	26.6
Vault Transformers	139	1,392	12,409	11.2
Pole Mounted Transformers	221	2,214	30,709	7.2
Pad Mounted Transformers	167	1,668	5,609	29.7
Wood Poles	2,613	26,128	159,700	16.4
Pad Mounted Switchgear	61	614	742	82.7
Underground Cable In Duct (km)	0	0		
Underground Cable Direct Buried (km)	140	1,396		
Network Vaults	0	0		
Cable Chambers	129	1,292	10,071	12.8
TOTAL	4,078	40,777		

3.2 *Asset Condition Based Replacement Model*

3.2.1 Methodology

In the asset condition-based model, the unit replacement forecasts are based upon an evaluation of asset condition against condition criteria. This method minimizes the errors of age-based methods where the age of the asset class may not be a true indicator of asset health, whether for the better or for the worse. This approach also lends itself to risk analysis of the results.

In the unit replacement forecasts the following steps were taken:

- Ascertain condition of assets

Primary Cable Direct Buried (circuit km)											1149
Network Vaults	0	1	1	8	8	8	8	8	8	8	58
Cable Chambers	9	10	10	22	22	22	4	4	4	4	111
TOTAL	3170	3788	3798	5564	5564	5564	5709	5648	5631	5631	50067

3.3 *Analysis*

A comparison of the total number of units replaced in a ten year time-span using the two methods may be found in Table 4.

Table 4 Comparison of age-based and asset condition based unit replacement forecasts

Asset Classes	Age based analysis 2007-2016 Total	Asset Condition based analysis 2007-2016 Total	TOTAL POPULATION	%
Station Transformers	147	142	287	49.4 X
Circuit Breakers	632	94	1732	5.4
Switchgear Assemblies	71	0	272	0.0
Buildings	0	0		
Network trans/protectors	826	658	2055	32.0 X
Submersible Transformers	2,209	2,101	8,289	25.3
Vault Transformers	1,392	1,340	12,409	10.8
Pole Mounted Transformers	2,214	10,698	30,709	34.8 X
Pad Mounted Transformers	1,668	1,101	5,609	19.6
Wood Poles	26,128	31936	159,700	20.0
Overhead Switches – Remote Operated	N/A	103	505	20.4
Pad Mounted Switchgear	614	67	742	9.0
Automatic Transfer Switches	N/A	72	113	63.7 X
Underground Cable In Duct (km)	0	401	1243	32.3 X
Underground Cable Direct Buried (km)	1,396	1,149	1271	90.4 X
Network Vaults	0	58	1048	5.5
Cable Chambers	1,292	111	10071	1.1
TOTAL	40,777	50,067		

the probability of a failure occurring and estimating the severity of the consequences in the event of such a failure. Components in poor condition and with severe consequences upon failure would be targeted for replacement first.

The risk analysis was conducted in six steps:

- Determine the probability of failure in each Health Index Class
- Identify the Consequence types (eg. Reliability)
- Define three consequence severity grades for each risk type
- Determine the proportion of each asset class in each consequence severity grade
- Identify the dominant risk type for each asset class
- Calculate the number of components in each risk level

Since the equipment to be replaced had already been defined by the Asset Condition Assessment and the risk analysis was only being used to prioritize replacements, only relative risks were used in the analysis instead of absolute dollar values of risk.

3.2.2 Forecast

Table 3 Unit replacement forecasts using Asset Condition Model

	Units in each year										
Asset Classes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Station Transformers	0	1	1	4	4	4	32	32	32	32	142
Circuit Breakers	0	7	7	8	8	8	14	14	14	14	94
Switchgear Assemblies	0	0	0	0	0	0	0	0	0	0	0
Buildings	0	0	0	0	0	0	0	0	0	0	0
Network trans/protectors	52	56	56	86	86	86	86	50	50	50	658
Submersible Transformers	168	179	179	225	225	225	225	225	225	225	2101
Vault Transformers	0	5	5	190	190	190	190	190	190	190	1340
Pole Mounted Transformers	856	910	910	1146	1146	1146	1146	1146	1146	1146	10698
Pad Mounted Transformers	11	55	55	88	88	88	179	179	179	179	1101
Wood Poles	1916	2396	2396	3604	3604	3604	3604	3604	3604	3604	31936
Overhead Switches - Remote Operated	0	0	0	1	1	1	25	25	25	25	103
Pad Mounted Switchgear	1	4	4	6	6	6	10	10	10	10	67
Automatic Transfer Switches	0	0	0	0	0	0	18	18	18	18	72
Underground Primary Cable In Duct (circuit km)	24	24	24	47	47	47	47	47	47	47	401
Underground	133	140	150	129	129	129	112	87	70	70	

2.2 Asset Replacement Costs

As an indicator only of the overall significance of each asset class to THESL, an estimate of the total replacement cost of the major assets has been made based on the data provided. The following Table 2-2 summarizes the input data.

Table 2-2 Total Replacement Value of Asset Classes[1]

Asset Class	Cost/Unit to Replace	Units	Population	Replacement Cost (million $)
U/G Feeder Cable - Direct Buried	$ 500[2]	m	300000	150.00
U/G Dist Cable - Direct Buried	$ 280[2]	m	1188000	332.64
U/G Feeder Cable - in Duct	$ 150[3]	m	754000	113.00
U/G Dist Cable - in Duct	$ 150[3]	m	3016000	452.00
Poles	$ 5,780[4]	each	159000	919.02
O/H Transformers	$ 4,266	each	30709	131.00
U/G Transformers	$ 12,000	each	8289	99.47
Padmount Transformers	$ 25,000	each	5609	140.23
Building Vault Transformers	$ 12,000	each	12409	148.91
Network Transformers/protectors	$ 85,000	each	2055	174.7
O/H Switches - Manual	$ 8,000	each	946	7.57
O/H Switches - Remote	$ 25,000	each	505	12.63
UG ATS Switches	$ 19,428	each	113	2.20
Padmount Switches	$ 26,035	each	742	19.32
Cable Chamber Roof Replacement	$ 12,000	each	10071	120.85
Vault Roof Replacement	$ 22,566	each	1084	24.46
Stations Transformers	$ 180,000	each	287	51.66
Stations Circuit Breakers	$ 30,000	each	1732	52.00
Stations Switchgear	$ 1,750,000	each	272	476.00
Stations Buildings	$ 5,000,000	each	16	80.00

NOTES
1 The replacement cost per unit data was obtained from THESL's "Electric System Distribution Asset Strategy 2006" Table A1-1
2 Direct buried cable is replaced with cable in concrete encased duct
3 Does not include replacing the duct structure
4 The figure for poles includes insulators, hardware and conductors.
5 It was assumed that 20% of the cable was feeder cable and 80% distribution cable
6 Replacement costs provided may be maximum values rather than average values

The asset classes listed in Table 2-2 are not intended to be an exhaustive list of the asset classes of THESL but a list of the most important for determining priorities. Total replacement costs calculated for the assets of Table 2-2 therefore does not represent the total replacement value of the assets of THESL.

The two methods produced similar results for the following asset classes:

- Station transformers
- Submersible transformers
- Vault transformers
- Underground direct buried cable

The two methods produced different results for the following asset classes:

- Circuit breakers
- Switchgear assemblies
- Pole mounted transformers
- Pad-mounted transformers
- Overhead switches
- Pad-mounted switchgear
- Automatic transfer switches
- Underground cable in duct
- Cable chambers

In the case of circuit breakers and switchgear assemblies, the difference between the two methods can be explained by the condition-based analysis' lack of ability to capture obsolescence issues. The age-based analysis is limited to the age of the equipment and therefore captures obsolescence issues.

It is unusual for a condition-based analysis to direct more unit replacements than an age-based approach. The differences may be explained by a too long a life span predicted for pole-top units. In addition, condition data is typically not collected for pole-top units as they are not easily accessible for maintenance. These two factors may have led to the stated difference.

For automatic transfer switches and underground cable in duct, the condition-based analysis identified replacement needs that were not captured by the age-based analysis.

A significant discrepancy exists between the two methods with respect to cable chambers. The condition-based analysis was believed to provide more realistic results in this instance as civil structures in good environments can last substantially longer than if only an age-based assessment was carried out.

3.4 Recommended Unit Replacement Forecast

The results presented in 3.1.2 and 3.2.2 were compared with differences explained in 3.3. In general, the condition-based method was used to guide the unit replacement forecast unless a valid reason was found to deviate as was discussed in 3.3. The results were examined in light of the fact that asset classes work in groups and that it is cost effective to replace assets in groups. The results were also examined in light of execution feasibility by THESL. Based upon these analyses, the recommend unit replacement forecast is listed in Table 5.

Table 5 Recommended unit replacement forecast

Asset Classes	Units in each year										
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Station Transformers	6	6	6	7	7	7	7	6	5	5	61
Circuit Breakers	23	22	23	25	25	25	25	23	21	21	232
Switchgear Assemblies	4	4	4	4	4	4	4	4	4	4	40
Buildings	0	0	0	0	0	0	0	0	0	0	0
Network trans/protectors	55	59	64	69	69	69	69	64	58	58	634
Submersible Transformers	327	597	635	688	688	688	688	635	587	587	6118
Vault Transformers	33	25	26	29	29	29	29	26	24	24	273
Pole Mounted Transformers	452	341	363	393	393	393	393	363	335	335	3761
Pad Mounted Transformers	109	172	180	193	193	193	193	180	169	169	1750
Wood Poles	1431	1080	1149	1243	1243	1243	1243	1149	1061	1061	11902
Overhead Switches - Remote Operated	50	50	50	50	50	50	50	50	50	50	500
Pad Mounted Switchgear	30	56	59	64	64	64	64	59	55	55	571
Automatic Transfer Switches	5	5	5	5	5	5	5	5	5	5	50
Underground Cable In Duct (conductor km)	77	50	53	58	58	58	58	53	49	49	561
Underground Cable Direct Buried (conductor km)	124	230	245	266	266	266	266	245	226	226	2361
Network Vaults	10	10	10	10	10	10	10	10	10	10	100
Cable Chambers	30	30	30	30	30	30	30	30	30	30	300
TOTAL	2766	2736	2902	3132	3132	3132	3132	2902	2690	2690	29214

3.5 Sustaining Capital Requirements

Table 5 was further simplified by grouping assets that work together as part of the distribution system and then estimates generated for the unit replacements of assets in each group. THESL forecasts that it will need to make sustaining capital investments of approximately $1.2 billion over the next ten years to maintain asset condition. Nearly half will need to be invested to replace underground direct buried distribution systems. It also forecasts that the rest of its underground distribution system and its overhead system will need $210 million and $182 million respectively over the next ten years. Investments in transformer stations, municipal stations and network electrical distribution systems will require investments of $95 million, $60 million, and $58.5 million respectively over the next ten years. The ten-year forecast for sustaining capital per distribution group is presented in Table 6.

Table 6 Sustaining capital requirements 2007-2016

Group	Sustaining Capital Required per Year ($ 000,000)										Total	% of total
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
Underground Direct Buried Distribution	29.6	55.0	58.5	63.5	63.5	63.5	63.5	58.5	54.0	54.0	564	50
Underground Non-direct Buried Distribution	28.9	18.7	19.9	21.6	21.6	21.6	21.6	19.9	18.4	18.4	210	17
Overhead Distribution	22.1	16.5	17.6	19.1	19.1	19.1	19.1	17.6	16.2	16.2	182	15
Network Systems	5.1	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	58.5	5
Transformer Stations	9.4	8.8	9.4	10.2	10.2	10.2	10.2	9.4	8.6	8.6	95	8
Municipal Stations	7.0	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	60	5
Total	102.1	110.0	117.0	127.0	127.0	127.0	127.0	117.0	108.0	108.0	1,170	100

The recommended investments focus on the key asset classes that require replacement and focus investments in proportion to the need identified in the Asset Condition Assessment and age-based studies. The recommended plan is certain for the period 2007-2010. An Asset Condition Assessment will be required after a few years of progress in the recommended plan in order to make any adjustments to the plan given data uncertainty or a difference in actual component performance as compared to predicted performance.

Appendix A

Ten Year Plan

Portfolio Number	Capital Category	Year										Total
		[redacted]	2011	2012	2013	2014	2015	2016	2017	2018	2019	$ Millions
1	Underground Direct Buried Cable	[redacted]	$60.0	$60.0	$50.0	$50.0	$50.0	$50.0	$5.0	$5.0	$5.0	$405.3
2	Underground Rehabilitation	[redacted]	$22.0	$22.0	$22.0	$20.0	$18.0	$18.0	$18.0	$17.0	$16.0	$209.3
3	Overhead Systems	[redacted]	$19.0	$19.0	$19.0	$18.0	$16.0	$16.0	$16.0	$16.0	$16.0	$177.0
4	Network Vaults	[redacted]	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0	$59.7
5	Transformer Stations	[redacted]	$10.0	$12.0	$13.0	$18.5	$18.0	$18.0	$14.0	$14.0	$20.0	$153.4
6	Municipal Stations	[redacted]	$6.0	$5.0	$4.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$51.8
	SUSTAINING CAPITAL TOTAL	[redacted]	$123.0	$124.0	$114.0	$117.5	$113.0	$113.0	$64.0	$63.0	$68.0	$1,056.5
7	Reactive	[redacted]	$21.3	$21.3	$20.0	$20.0	$20.0	$18.0	$18.0	$18.0	$18.0	$197.1
8	Customer Connections	[redacted]	$32.0	$32.0	$35.0	$35.0	$35.0	$38.0	$38.0	$40.0	$40.0	$357.5
9	Engineering Capital	[redacted]	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$300.1
	TOTAL TRADITIONAL OPERATIONS	[redacted]	$206.3	$207.3	$199.0	$202.5	$198.0	$199.0	$150.0	$151.0	$156.0	$1,911.2
	EMERGING REQUIREMENTS											
10	Standardization	[redacted]	$22.7	$10.8	$13.3	$10.4	$5.8	$5.2	$5.2	$5.4	$5.2	$116.7
11	Downtown contingency (feeder-tie)	[redacted]	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$313.0
12	Worst Performing Feeder (WPF)	[redacted]	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$5.5	$55.0
13	Smart Grid Operations	[redacted]	$3.4	$3.0	$3.4	$4.8	$5.7	$7.6	$8.6	$9.9	$12.4	$61.9
14	Externally Initiated Plant Relocation	[redacted]	$46.6	$33.8	$65.6	$30.9	$11.3	$15.7	$5.4	$4.8	$6.3	$248.3
15	Stations System Enhancement	[redacted]	$69.5	$42.8	$17.5	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$149.0
16	Secondary Upgrades	[redacted]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.5
17	Environmental Footprint	[redacted]	$2.3	$3.4	$1.9	$1.1	$0.7	$0.4	$1.0	$0.0	$0.4	$11.3
18	Capacity Growth	[redacted]	$2.7	$9.1	$6.9	$6.7	$4.8	$14.2	$13.9	$8.5	$11.9	$78.7
19	Rear Lot Rebuild	[redacted]	$9.8	$16.8	$15.0	$15.0	$18.5	$26.7	$24.4	$23.5	$23.4	$173.1
20	URD System (rebuild)	[redacted]	$1.2	$1.2	$1.2	$1.2	$1.2	$0.0	$0.0	$0.0	$0.0	$6.0
21	Lead Cable	[redacted]	$42.9	$42.9	$42.9	$42.9	$42.9	$42.9	$42.9	$42.9	$42.9	$386.1
22	OH System Rebuild (Box Design)	[redacted]	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$2.3	$20.7
	TOTAL EMERGING REQUIREMENTS	[redacted]	$240.2	$203.0	$206.9	$152.4	$130.2	$152.0	$140.7	$134.4	$141.7	$1,626.3
	TOTAL CAPITAL PLAN	[redacted]	$446.5	$410.3	$405.9	$354.9	$328.2	$351.0	$290.7	$285.4	$297.7	$3,537.5
	Contributions from Customers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL (NET)	[redacted]	$415.0	$384.0	$365.6	$328.5	$309.7	$329.5	$273.4	$267.5	$279.2	$3,295.1

condition.

Assets that require the most significant investments in the next ten years are:

- 61 percent of direct-buried underground cable
- 31 percent of underground cable in-duct
- 63 percent of automatic transfer switches
- 50 percent of station transformers
- 35 percent of pole mounted transformers
- 32 percent of network transformer/protector units

Asset age is also a useful indicator of the state of assets, and is particularly useful for determining the geographic concentration of areas requiring investment. Figure 2 below displays the equipment age in the city, grouped into five-year categories.

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E6.1 Underground Circuit Renewal

INSTALLING NEW SUBMERSIBLE BUILDING VAULT SF6-INSULATED SWITCH

E6.1.1 Summary

Program Description

The Underground Circuit Renewal program replaces end-of-life and obsolete assets that contribute to the deterioration of system reliability. The program is a continuation of activities previously described in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 IRM/ICM rate application.

The Underground Circuit Renewal program replaces three assets types: underground switches, transformers and cables. These assets are primary components of an underground distribution system, and degrade due to age and exposure to harsh field environments. Proactive renewal is needed to ensure that reliability, safety and environmental risks are properly mitigated.

The anticipated benefits of the Underground Circuit Renewal program are as follows:

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CAPEX ($M)	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5

Given that a high population of assets will be approaching the end of their useful lives in 2015, Toronto Hydro expects to maintain a level of investment similar to the forecasted 2014 magnitude throughout the 2015-2019 period. Minor fluctuations in the pacing of investment over the forecast period (e.g. the drop in spending in 2016 and 2017) will likely be required to facilitate other high-priority renewal and service investments in the underground system using similar resources. The proposed rate of investment in the Underground Circuit Renewal program will allow Toronto Hydro to prudently and proactively manage the significant backlog of end-of-life and poor condition underground assets, maintaining system reliability performance while enhancing customer value with the installation of more robust and reliable underground construction.

TABLE 1: UNDERGROUND CIRCUIT RENEWAL PROGRAM ASSET REPLACEMENT UNITS

Assets (Units)	2015	2016	2017	2018	2019	Total
Underground Switches	84	71	74	88	88	405
Underground Transformer	348	291	305	362	361	1,667
Underground Cable (circuit km)	150	126	132	156	156	720

TABLE 2: SUMMARY PROGRAM BENEFITS

Customer Value	▪ Installing newer assets allows for reduced customer disruption in the event of an outage (i.e. quicker restoration due to SCADA switches and no digging for cable replacement). ▪ Improved neighborhood aesthetics depending on the age and condition of existing assets (i.e. heavily rusted transformers and switches). ▪ The completion of the first year of activities in this program is expected to result in an avoided estimated risk cost (ARC) of $102 million. A positive ARC value is indicative of a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) through the renewal of the assets within this program (see Section E6.1.7).
Reliability	Proactively replacing assets with a high risk of failure will: ▪ Reduce customers interruptions ▪ Mitigate safety risks to employees ▪ Minimize reactive repair costs
Safety	▪ Minimize safety related issues due to flashovers (seen with pad-mounted and submersible switches and non-switchable submersible transformers). ▪ Minimize the risk associated with dig-ins of direct buried cables and cables in direct buried PVC ducts.
Efficiency	▪ Improved restoration time by replacing older and unreliable assets with modern equipment capable of remote sensing and operation (i.e. switchgear). ▪ Improved isolation of transformers without affecting power supply to customers on the rest of the distribution system. ▪ Faster cable replacement of underground cables due to the concrete encased duct infrastructure.
Other (flashovers, dig-ins)	▪ Elimination of routine CO_2 washing used to maintain pad-mounted switches. ▪ Complete removal of cables in duct when a feeder is abandoned rather than dead-ending the cables and leaving it in the ground where removal of direct buried cables is not economically feasible.

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015 and for each following year effective January 1 through to December 31, 2019.

RESPONDING SUBMISSION OF TORONTO HYDRO

(on Motion by AMPCO returnable January 19, 2015)

1. On December 31, 2014 the Association of Major Power Consumers in Ontario ("AMPCO") filed a Notice of Motion seeking an order requiring Toronto Hydro-Electric System Limited ("Toronto Hydro") to provide full and adequate responses to those questions posed by AMPCO at the Technical Conference in which it requested that Toronto Hydro provide historical information for the period 2010 to 2014 of the quantities of particular asset units replaced (e.g., switches, transformers, poles, etc.) and the spending for those particular units for a number of asset replacement programs.

2. This information is apparently required by AMPCO to derive an estimate of unit cost (e.g., $/pole).

3. The specific information requested by AMPCO is not relevant because it would not properly permit the comparison of unit costs. In addition, the information sought cannot be extracted from the project information in an accurate manner in a reasonable time frame, even with significant effort and resources. Accordingly, it is Toronto Hydro's submission that AMPCO's motion should be dismissed.

Resulting Data Would Not be Relevant

4. Even if the data sought could be obtained in a reasonable time frame (which it cannot), the unit cost information requested by AMPCO would not permit the meaningful comparison of unit costs over time since the data would not provide insights with respect to what happens on a particular project design or execution of a particular project (Technical Conference Transcript, Vol. 1, p. 101). As the requested information would not properly permit the comparison of unit costs, it is not relevant to the proceeding and its production should not be required.

5. By way of example, during the Technical Conference AMPCO suggested that Toronto Hydro could take the total number of poles to be installed over a period of time, break them out into wood and concrete and calculate the relevant unit cost. In response, Toronto Hydro's General Manager of Engineering and Investment Planning, Mr. Walker, indicated that while mathematically such a calculation was possible, the result would be a number that does not actually represent a standard unit cost (Technical Conference Transcript, Vol. 1, p. 97). This is because the associated costs relate to circumstances unique to that particular project in which the asset unit was used. Varying circumstances (such as an asset replacement in a suburban area versus the downtown core) will present different cost results even through the same asset is replaced. The asset and work undertaken each time an asset is employed or replaced are not uniform as in a manufacturing process where unit costs are more appropriately measured (Affidavit of Mike Walker, attached hereto as **Schedule "A"**, at para. 11).

6. By way of further example, when counsel for AMPCO asked about the possibility of calculating the dollars per kilometer of PILC cable replacement and whether the resulting information would be valuable in assessing the reasonableness of the proposed spending, Mr. Walker similarly indicated that while this would produce an average cost it would not produce a consistent cost or a cost that would be comparable as between prior completed jobs and planned future jobs. For example, Mr. Walker noted that while some work involves patching a small segment of cable length, in other jobs entire sections would be replaced, thereby rendering the proposed calculation meaningless (Technical

Conference Transcript Vol. 1, pp. 99-100). Similarly, when asked whether an historical average compared to the average of the planned future spending period would provide a meaningful number, Mr. Walker responded that an average would not be meaningful because the mix of work within a program or portfolio in a given year would differ year over year and so such numbers would be misleading (Technical Conference Transcript Vol. 1, p. 100; Affidavit, para. 9).

7. Toronto Hydro's approach to tracking project costs recognizes the diverse range of work environments and circumstances that are encountered by Toronto Hydro across its system. Given this approach and that the circumstances of each job varies greatly, it would be very challenging to reconcile the unit costs of particular assets as between different jobs (Technical Conference Transcript, Vol. 1, p. 94).

8. As described at para. 12 in the Affidavit of Mr. Walker, the range of variables that would be encountered, for example on a typical pole installation project, is broad and would include such aspects as the relevant ground conditions, location, number of circuits, voltage of those circuits, whether the poles will carry circuits with a single or multiple voltages, whether there will be a need for underground risers, transformer type, guying, work time restrictions, etc. Toronto Hydro can encounter any one or more of these variables in the field, which would affect the cost of the project. For example, a pole installation in concrete could cost more than a pole installation in soil, a pole installation outside of business hours could cost more than during regular business hours, and pole installation in the downtown core could cost more than in a suburban area of the city.

9. It is also important to note that approximately 81% of Toronto Hydro's distribution system capital costs (i.e. all electrical material costs, all civil construction costs, and a portion of electrical design and construction work) are subject to market driven pricing, and are therefore outside of Toronto Hydro's direct control (Affidavit, para. 7). In addition, the method by which a contractor accounts for costs or values assets to be replaced will vary between contractors and will be adapted to facilitate responses to Toronto Hydro's rigorous competitive procurement processes. As a result, the value to the Board of the data sought is further diminished.

Costs are Accounted for on a Project Basis

10. As explained by Mr. Walker, Toronto Hydro measures, tracks and manages its project costs by comparing its actual costs for specific jobs within a project to its design estimate for each specific job within a project (Technical Conference Transcript, Vol. 1, p. 98). Following high-level project planning, Toronto Hydro's designers prepare a design estimate for each particular job or activity that forms part of the project. That estimate will take into account the specific requirements for that job or activity, having regard to the circumstances unique to that job or activity. These include factors such as its location, the number of circuits involved, parking or timing of work restrictions and other relevant circumstances that are specific to the planned job or activity. During and post-completion, Toronto Hydro measures its performance against the design estimate for the particular job or activity. If a significant variance is found, Toronto Hydro then conducts a project variance analysis to determine the cause(s) of the variance and any lessons learned that may be helpful for future projects.

11. Toronto Hydro experiences significant diversity in its project activities over time. It has been Toronto Hydro's experience that the mix of work within a program or portfolio in a given year may not be consistent from year to year (Affidavit, para. 9). Because of this diversity Toronto's practice is to measure, track and manage its project costs relative to the design estimates that are prepared on a project by project basis or job by job basis rather than by comparison of unit costs between programs or from year to year.

12. As further explained by Mr. Walker, Toronto Hydro does not consider costs on a per-asset basis (Technical Conference Transcript, Vol. 1, pp. 96-97). With respect to projects or jobs that are bid on by and awarded to outside contractors, the bid costs reflect logical groupings of assets, as well as associated material, labour, overhead and other costs that contractor will charge, regardless of their actual cost to construct. With respect to work that is performed using internal resources, Toronto Hydro instead tracks actual project costs through a detailed work order process (Affidavit, para. 6).

13. As a result of the foregoing, it would be extremely complex and time-consuming for Toronto Hydro to review each designed and completed job for the purpose of extracting

the asset units and related costs. In effect, the costs and asset units are woven into the project accounting.

14. This problem is further complicated by the functionality of Toronto Hydro's IT framework for managing project information. In particular, through Toronto Hydro's custom applications and existing enterprise resource planning ("ERP" or "Ellipse") system project information is transformed at various stages of a project's lifecycle. These transformations can involve changes in scope, the splitting or combining or phasing of scopes, advancing or deferring scopes between years, etc. Each transformation represents a new stage in the project lifecycle, which is not automatically reconciled to previous stages (Affidavit, para. 18).

15. This process of reconciling executed work and costs against the initially planned work and costs requires a labour-intensive and extensive mapping exercise so as to account for each of the transformational steps back to the original project scope that informed the underlying regulatory filing (Affidavit, para. 17-18).

The Requested Information Can Only be Provided with Significant Time and Resources

16. Having regard to the manner in which Toronto Hydro measures and tracks its project costs, as well as the limitations of its Ellipse system, the information requested by AMPCO could only be ascertained and provided if Toronto Hydro were to dedicate and divert considerable resources over a significant period of time.

17. As described in para. 18 of the Affidavit, it is estimated that this effort would require three full time resources and would take approximately one full year to complete. This level of resources and time commitment is required because, as explained in para. 16 of the Affidavit, the unit cost for installing or replacing a particular piece of equipment will not be apparent from any particular work order but must instead be derived from a labour-intensive process of manually allocating costs from numerous work orders to the relevant assets associated with a project, and repeating this for each project within a given program.

18. It is Toronto Hydro's submission that the level of resources and time needed to provide this information is unreasonable as it would require Toronto Hydro to divert significant resources away from normal business activities - including the execution of its capital program - and has real potential to cause delay in the proceeding. Given the relevance and usefulness of the data, and the foregoing complication with extracting the data, the production of such information should not be required.

All of which is respectfully submitted this 13th day of January, 2015.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By its Counsel

Torys LLP

for

Charles Keizer

TAB 2A

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015 and for each following year effective January 1 through to December 31, 2019.

AFFIDAVIT

I, Mike Walker, of the City of Toronto, in the Province of Ontario, MAKE AN OATH AND SAY:

1. I am the General Manager, Engineering and Investment Planning, Toronto Hydro Electric System Limited ("Toronto Hydro") and, as such, have knowledge of the matters to which I herein depose.

2. As the General Manager, Engineering and Investment Planning, my responsibilities include capacity and generation planning, as well as asset lifecycle planning for all assets within Toronto Hydro's distribution system; annual capital investment planning; annual maintenance investment planning; design, material and equipment standards development and maintenance; and engineering policy development and maintenance.

3. In evidence filed on July 31, 2014 in support of its application in EB-2014-0116 (the "Pre-filed Evidence"), Toronto Hydro describes a number of discrete capital investment programs which together comprise Toronto Hydro's 2015-2019 Distribution System Plan ("DSP"). Toronto Hydro filed detailed business case evidence in support of each of these programs (Exhibit 2B, Sections E5.1 to E8.8).

4. For some of the capital investment programs,[1] Toronto Hydro provided forecast estimates of the quantities of certain asset units that it expected to replace, install or remove (depending on the nature of the program) in each year of the DSP. While Toronto Hydro was able to

[1] E6.1, E6.2, E6.4, E6.5, E6.6, E6.7, E6.8, E6.9.

provide these estimated asset quantities on a forecast basis at the program level, as a component of forecasting its cost estimates in the business cases, it did not provide the corresponding costs for the particular assets. In addition, its ability to provide estimated asset quantities does not speak to Toronto Hydro's ability to provide historical information on the quantities of particular asset units installed, removed or replaced, or the corresponding costs on a per-unit basis.

Measurement and Tracking of Project Costs

5. Capital investment programs are implemented through the completion of specific projects. Toronto Hydro designs and executes its capital work on a project basis. A project consists of all of the activities that are involved in removing, replacing or installing a group of assets within a particular geographic location. A project's cost consists of the blended costs of the various activities that together comprise the project.

6. Project costs are measured and tracked differently, depending on whether the work is being performed internally or externally. If the work, or a portion of it, has been contracted, the costs reflect the contractor's bid price for the civil materials, labour, overhead and other costs necessary to execute the work (with the exception of electrical equipment that is provided by Toronto Hydro). The contractor is bound to their bid price even if their actual costs of completing the project differ. If the work is being performed using internal resources, the costs represent the actual material, labour and equipment costs incurred by Toronto Hydro to execute the work, which are tracked through a detailed work order process.

7. Approximately 81 percent of Toronto Hydro's capital costs in its electrical work program are subject to competitive market forces. This includes the costs of all electrical equipment, which Toronto Hydro procures for use on its system (whether or not such equipment is installed by internal resources or outside contractors), all civil construction related costs, and costs related to electrical design and construction work provided by outside contractors, all of which are sourced through competitive processes. The remaining 19 percent of Toronto Hydro's capital costs in its electrical work program are attributable to the internal labour and vehicle costs in connection with the relevant projects. As a consequence of there being a high proportion of Toronto Hydro's capital costs subject to competitive market forces, the level of those costs on a per unit basis is largely outside of Toronto Hydro's control. Competitive

market pressures already ensure that Toronto Hydro is able to obtain the lowest cost per unit that the market can bear, for the majority of its project spending.

8. Project costs are influenced by the variety of circumstances and factors that Toronto Hydro encounters across its large and diverse system. For example, pole installations as part of an Overhead Circuit Renewal project can be subject to variables such as the following: installation in soil or in concrete; location of the pole (i.e. downtown, suburban, road with or without parking); type and number of connected circuits (i.e. single phase, three-phase, 27.6 kV, 13.8 kV, 4.16 kV, or combination of these); type and number of other equipment installed on the pole (i.e. switches, risers, transformer, etc.); and the loading conditions and switching requirements applicable to the pole. These variables can change from project to project, or from pole to pole within a project. The unique combination of variables encountered on a particular project will affect the cost of that project. For example, on a pole installation project the cost of the project will be affected by such factors as whether the poles need to be installed in concrete as compared to soil, or whether the poles can be installed during regular business hours or must be installed outside of regular business hours.

9. Because of the diverse conditions and circumstances encountered across Toronto Hydro's system, the mix of work within a project and the mix of projects within a program vary considerably from year to year. As an example, the majority of projects in the Overhead Circuit Renewal program in a given year may be executed in the suburbs where crews generally encounter fewer restrictions and complexities when installing poles. The next year, the bulk of the work within the program may shift to the downtown core, where pole installations are typically more complex and time consuming. As a result of these geographical differences, the number of pole installations would likely be significantly higher but with much lower costs in the first year as compared to the second year. A comparison of the cost per pole installed in these years would not reflect the diverse conditions and circumstances encountered and, as a result, would not be meaningful.

10. Given the complexities described above, Toronto Hydro plans, designs and tracks work on a project by project basis, rather than on an asset by asset basis. As such, rather than considering the unit cost of a particular asset on one project or in one period relative to the unit cost of the same type of asset on another project or in another period, Toronto Hydro instead considers the actual costs of a project relative to the estimated costs for that particular

project, where the estimate will have taken into account the known circumstances and conditions unique to the particular project.

11. Unit costing is a common consideration in manufacturing, where the output is the production of consistent, uniform and repeatable units. In that context, unit costing enables the manufacturer to track the unit costs by standardizing production through an assembly line manufacturing process, with the objective of every product off the line being identical in form and quality, and every step in production being consistent and optimized.

12. Toronto Hydro is subject to many variables outside of its control in meeting its service requirements and managing its large and complex system. A unique combination of variables is encountered on each project and that unique combination of variables gives rise to a cost profile that is unique to the particular project. These include variables such as system configuration, system voltage, construction standards, number of circuits/phases, switching requirements, system loading, location within the City, type of street, site access restrictions, soil/ground conditions, seasonal/weather impacts, timing of work execution, condition of associated assets, third party coordination requirements, and presence of other utility plant.

Project Accounting Processes

13. Toronto Hydro's capital projects begin as "scopes" of work that are created in a custom scoping application by planning engineers who have experience identifying, prioritizing and planning investments within one or more discrete capital programs. Using the utility's suite of planning tools and databases, these engineers exercise professional judgement to create project scopes that address discrete assets (e.g. stations circuit breakers), arrays of like assets (e.g. polymer SMD-20s), or geographic/feeder based investment needs (e.g. Overheard Circuit Renewal).

14. Once the investment needs within a particular project scope are fully specified, the engineer produces a "high-level estimate" of the project cost using the utility's Enterprise Resource Planning ("ERP") system (currently Ellipse). The engineer then delivers the scope package to a program management consultant, who reviews the scope and determines the resources and scheduling of the work. At this stage, the scope may be split, combined, phased, advanced or deferred based on the project management consultant's recommendations.

15. The project then moves to detailed design where a designer is tasked with assessing site-specific construction needs through field visits, the Geographic Information System (GIS) and other available records. The scope of the project could be modified at this point in the process. Using this information and their professional experience, designers produce construction drawings and an accompanying detailed design estimate in Ellipse. When the design is complete, the designer "packages" the estimate in Ellipse, which results in the creation of new identifiers called "Projects" and "Work Orders". It is not until the estimate is packaged that Ellipse establishes a transactional record for the project.

16. As a result of the process described above, the "unit cost" for installing or replacing a particular piece of equipment, such as a pole installation, will not be apparent from any particular work order. Rather, the cost of each installed or replaced asset unit will be made up of costs that would be found in multiple work orders, each of which addresses a discrete set of tasks that contributes to that installation or replacement (i.e. one work order for setting the poles, another for framing them, etc.). As such, deriving the unit cost for the installation or replacement of a particular asset will involve allocating the costs of those multiple work orders to the relevant assets, which on account of the diverse conditions and circumstances encountered in the field may require certain estimates or assumptions to be made. It is not uncommon for there to be dozens of work orders associated with a particular project. As such, the process would be expected to be very labour-intensive, given that a program is made up of a number of individual projects.

17. Toronto Hydro's ERP system does not provide the capability to create or manage a master record for a capital project throughout its entire lifecycle. Toronto Hydro can track project execution costs against Ellipse projects and work orders, and can be compared to packaged design estimates. However, in order to report project variances or historical unit costs on a program basis, the utility must manually map this transactional record back to the original project scopes. As mentioned previously, these scopes are created in a custom application with no linkage to Ellipse. Scopes are subsequently managed in different custom tools as the project information is transformed at various stages in its lifecycle. The reconciliation of each of the previous steps in the lifecycle of the project requires significant manual effort, which is further compounded by the process described in paragraph 16 above.

Feasibility of Providing the Information Requested by AMPCO

18. To provide the information requested by AMPCO, Toronto Hydro would have to manually reconcile the costs of executed projects against the scope of work initially developed for each corresponding project. Through such a process, Toronto Hydro would need to determine the quantities and costs for the assets in question and aggregate those asset quantities and costs back to the specific projects and programs where they originated, while taking into account any scope changes that may have occurred over the lifecycle of the project. Toronto Hydro would also have to manually derive the unit costs for each of the assets in question for each project by way of analyzing each work order for a project to allocate costs. This data is not readily available within Ellipse. This process would be very labour- intensive. Toronto Hydro estimates that if it were to dedicate three staff from the System Planning and Project Management functions on a full-time basis, it would take a duration of approximately one year to manually derive all of the unit cost information requested by AMPCO.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario, this 13 day of January, 2015	
Commissioner for Taking Affidavits Elias Lyberogiannis (LSUC #: 64499C)	Mike Walker

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January 21, 2015

RESS, EMAIL & COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro") Custom Incentive Rate Application (EB-2014-0116)

We are counsel to the applicant, Toronto Hydro, in the above referenced proceeding. On January 19, 2015 Toronto Hydro and the Association of Major Power Consumers in Ontario (AMPCO) reached a settlement on AMPCO's motion of December 31, 2014. As part of the settlement, Toronto Hydro agreed to provide certain information in response to AMPCO's information requests, as detailed before the Board on January 19, 2015. Enclosed, please find Toronto Hydro's responses.

Yours truly,

Jonathan Myers

cc: A. Klein and D. Coban, THESL
C. Keizer and C. Smith, Torys LLP
All Parties

13398-2009 18730607.1

AMPCO Motion Settlement: Toronto Hydro Response

A. Background

For purposes of settling and the withdrawal of the motion brought by the Association of Major Power Consumers in Ontario ("AMPCO") dated December 31, 2014, Toronto Hydro agreed to provide the information set out below. This information is provided without prejudice to Toronto Hydro's position that unit and cost information obtained for the purpose of calculating a unit cost is irrelevant and Toronto Hydro is free to make submissions in this regard in the future.

1. For the Distribution System Plan ("DSP") programs that AMPCO identified in its motion (i.e. E6.1, E6.2, E6.4, E6.5, E6.6, E6.7, E6.8 and E6.9), and for the specific asset types identified for each program in the same motion, Toronto Hydro agreed to provide, on a best efforts basis, numbers of assets and the dollar values associated with those assets for the years 2012 and 2013, and for the period of January to June, 2014. This information is only available on an in-service additions basis, as opposed to a capital expenditures basis.

2. Toronto Hydro agreed to provide the same information, on a best efforts basis, for the major asset types identified in programs E6.10, E6.13, E6.14 and E6.15, which were not included in AMPCO's motion or original request.

3. For the subset of capital programs listed in points 1 and 2 above, Toronto Hydro agreed to provide the number of units to be replaced in 2015 for programs that are planned on a discrete asset basis (as opposed to programs that are planned on a geographical basis), and the associated program spending for 2015.

B. Discrete Investment Programs

Further to item 3, above, the following table lists the programs within the designated subset of DSP capital programs requested by AMPCO that address discrete asset replacements, as opposed to geographically planned rebuilds or refurbishments. While these programs are driven by the replacement of a specific major asset type, the expenditures can also include a number of other related assets, depending on the nature of each individual project. As such, a simple division of planned program expenditures by the number of units for the corresponding major asset type will not yield an asset-specific average cost that is directly comparable to the historical data provided for 2012-2014.

Table 1: Discrete Investment Programs

DSP Program	Major Asset Type (Installed)	Examples of other major assets in a project
E6.8 SCADA-Mate R1 Switch Renewal	Overhead Switch	RTU, Wooden Poles
E6.9 Network Vault Renewal	Network Vault	Network Units, Underground Cable
E6.10 Network Unit Renewal	Network Units (Transformers & Protectors)	Underground Cable
E6.13 Switchgear Renewal	Stations Switchgear (TS & MS)	Station Battery, Circuit Breakers
E6.14 Power Transformer Renewal	Stations Power Transformer	Bus Structure
E6.15 Circuit Breaker Renewal	Stations Circuit Breaker	Relays

C. Description of Data Provided

Historical Data

As explained in Ms. Rouse's affidavit dated January 16, 2015 (the "Rouse Affidavit"), Toronto Hydro is able to provide historical data for the years 2012 and 2013 using the utility's financial reporting system and by leveraging the detailed program mapping exercise that was carried out in preparing the DSP, specifically for the Incremental Capital Module ("ICM") program years (2012-2013). Historical data for 2014 (up to June) has been provided using the same sources. Data beyond June 2014 is unavailable as the year-end has not yet been closed-out or audited and the relevant program mapping exercise has not been completed.

The historical data provided is available only on an in-service basis. As explained in the Rouse Affidavit, not all capital expenditures in the years 2012 and 2013 (as well as 2014) would have gone into service in those same years. Similarly, in-service amounts associated with assets that came into service in any given year may include expenditures from prior years. Therefore, the costs and associated units provided in the tables in Section D below will not bear a direct relationship to the overall historical annual capital expenditure amounts provided in the spending summary tables in each of the identified programs.

It is also possible that a project that was placed into service in a given year could have lagging costs that appear separately as in-service additions in the following year. Therefore, the data that Toronto Hydro has been able to provide in Section D is not a true representation of average costs per unit.

As explained in the Rouse Affidavit, the financial asset classes that Toronto Hydro used to report historical actual units and costs in this response can include multiple different asset types with significantly different average costs. For example, the Overhead Switches asset class in Table 4, below, could include assets ranging from large three-phase gang-operated switches to single-phase manual cut-out switches. The financial asset sub-ledger cannot report at this lower level of detail.

It should also be noted that because this historical data is provided on an in-service basis, the units and costs necessarily represent the number of assets <u>installed</u>. This is distinct from the forecast information provided in the referenced DSP programs. The units provided in the DSP forecast tables for System Renewal programs represent the number of units to be <u>replaced</u>, <u>removed</u>, or otherwise <u>intervened upon</u> by that program. This is a particularly important distinction for programs that are not "like-for-like" in nature. For example, Toronto Hydro is planning to remove rear lot plant that may be situated either overhead or underground, depending on the area. However, regardless of the current rear lot configuration, Toronto Hydro replaces existing rear lot plant with front lot, underground plant. Therefore, the historical information provided will be based on the new front lot plant installed, whereas the forecast information will be based on the quantity of existing rear lot plant to be replaced. This means that the historical unit counts provided in Section D below are not directly comparable to the forecasted unit counts summarized in the DSP evidence.

Moreover, while some programs may on the surface appear to be "like-for-like", it is likely that the rebuilt plant will nevertheless differ on an asset unit count basis from the existing plant due to changes in design and construction standards, field conditions, feeder loading and other considerations over time. For example, Toronto Hydro may replace a larger number of existing low kVA rated transformers with a smaller number of higher kVA rated transformers in order to improve cost efficiency in the renewed feeder design.

Forecast Data

The forecast unit count and program cost information that Toronto Hydro has summarized in Section E is taken directly from the original DSP program evidence. As explained in Section B above, this information cannot be used to derive an average asset unit cost for the referenced asset types because overall program costs may include expenditures related to other types of assets.

The forecast information provided in Section E is total capital expenditures by program. The historical actual information for 2012-2014 is provided on an in-service basis. Accordingly, the data will not be directly comparable.

D. Historical Units and Costs (2012 to June 2014)

The tables provided in this section summarize the historical number of units and the in-service dollar amounts associated with those units for each of the programs and asset types requested by AMPCO. As explained in Mr. Walker's affidavit dated January 13, 2015 and filed by Toronto Hydro (the "Walker Affidavit"), the information provided below does not permit the meaningful comparison of unit costs over time since the data does not provide insights with respect to what happens on a particular project design or execution of a particular project.

Project costs are influenced by the variety of circumstances and factors that Toronto Hydro encounters across its large and diverse system. For example, pole installations as part of an Overhead Circuit Renewal project can be subject to the following variables: installation in soil or in concrete; location of the pole (i.e. downtown, suburban, road with or without parking); type and number of connected circuits (i.e. single phase, three-phase, 27.6 kV, 13.8 kV, 4.16 kV, or a combination of these); type and number of other equipment installed on the pole (i.e. switches, risers, transformers, etc.); and the loading conditions and switching requirements applicable to the pole. These variables can change from project to project, from pole to pole within a project, or from time to time. The unique combination of variables encountered on a particular project will affect the cost of that project. For example, on a pole installation project the cost of the project will be affected by such factors as whether the poles need to be installed in concrete as compared to soil, or whether the poles can be installed during regular business hours or must be installed outside of regular business hours.

Because of the diverse conditions and circumstances encountered across Toronto Hydro's system, the mix of work within a project and the mix of projects within a program vary considerably from year to year. As an example, the majority of projects in the Overhead Circuit Renewal program in a given year may be executed in the suburbs where crews generally encounter fewer restrictions and complexities when installing poles. The next year, the bulk of the work within the program may shift to the downtown core, where pole installations are typically more complex and time consuming. As a result of these geographical differences, the number of pole installations would likely be significantly higher but with much lower costs in the first year as compared to the second year. A comparison of the cost per pole installed in these years would not reflect the diverse conditions and circumstances encountered and, as a result, would not be meaningful.

Please note that in most cases the 2012 ISA unit counts and dollar amounts in the following tables are significantly lower than in 2013 and 2014, and in some cases are zeros. This is due to the ramp-down of Toronto Hydro's capital program that occurred following the decision in the utility's 2012-2014 Cost of Service application, and pending the Phase 1 IRM/ICM decision.

Table 2: E6.1 Underground Circuit Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Underground Cable	Underground Primary In-duct-XLPE	M	106,291	$ 6,715,307	283,719	$ 15,431,361	31,033	$ 1,524,924
Underground Switches	Underground Switch Installation	EA	36	$ 2,695,127	40	$ 3,115,838	3	$ 289,065
Underground Transformer	Underground Distribution Transformer	EA	85	$ 1,052,331	270	$ 4,747,080	122	$ 2,222,103

- Please note that Underground Cable is reported in terms of meters of cable in the above table. For the forecasted units that appear in the DSP program evidence, the amount of cable is represented in terms of circuit kilometres, which does not take into account the number of phases in a section of feeder. As such, these measures are not directly comparable.

Table 3: E6.2 Paper-Insulated Lead-Covered Leakers and Cable Piece-Outs

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Underground Cable	Underground Primary PILC	M	-	$ -	525	$ 111,443	579	$ 253,474

Table 4: E6.4 Overhead Circuit Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Wood Poles	Wooden Poles	EA	147	$ 1,047,156	2,672	$ 15,205,774	804	$ 4,051,829
Concrete Poles	Concrete Poles	EA	3	$ 16,505	39	$ 432,769	5	$ 68,159
Overhead Switches	Overhead Switches, Overhead SMD-20 Switches	EA	47	$ 849,687	569	$ 4,422,034	68	$ 286,201
Overhead Transformers	Overhead Polemount Transformers	EA	113	$ 1,320,316	730	$ 7,332,735	205	$ 2,203,596

Table 5: E6.5 Overhead Infrastructure Relocation

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Poles	Not Applicable - New Program in 2015							
OH Conductor (mts)								
OH Switches								
OH Transformers								
Underground Cable								

Table 6: E6.6 Rear Lot Conversion

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Poles	Wooden Poles	EA	2	$ 8,323	131	$ 1,219,236	-	$ -
Transformers	Underground Distribution Transformer, Overhead Polemount Transformers	EA	-	$ -	158	$ 2,547,017	47	$ 555,704
Manual Switch	Underground Switch Installation, Overhead Switches, Overhead SMD-20 Switches	EA	-	$ -	39	$ 599,518	12	$ 36,310
Fuse	Not Applicable - Not tracked in financial asset sub-ledger							
Riser								
Conductor (m)	Overhead Lines	M	-	$ -	2,581	$ 197,148	-	$ -
Cable (m)	Underground Primary In-duct-XLPE	M	-	$ -	40,937	$ 4,164,428	8,782	$ 715,142

Table 7: E6.7 Box Construction Conversion

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
OH Transformer	Overhead Polemount Transformers	EA	-	$ -	120	904,168	11	$ 7,330
OH Switch	Overhead Switches, Overhead SMD-20 Switches	EA	-	$ -	61	$ 326,611	3	$ 421
Poles	Wooden Poles, Concrete Poles	EA	-	$ -	257	$ 1,409,059	208	$ 722,496
UG Switch	Underground Switch Installation	M	-	$ -	-	$ -	-	$ -
UG Transformer	Underground Distribution Transformer	EA	-	$ -	12	$ 162,685	-	$ -
OH Conductor (km)	Overhead Lines	M	-	$ -	28,914	$ 644,636	5,173	$ 8,874
UG Cable (km)	Underground Primary In-duct-XLPE	M	-	$ -	4,272	$ 577,285	-	$ -

Table 8: E6.8 SCADA-Mate R1 Switch Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
R1 Switch	Overhead Switches	EA	-	$ -	31	$ 957,343	-	$ -
RTU	System Supervisory Scada RTU	EA	-	$ -	25	$ 732,206	-	$ -

Table 9: E6.9 Network Vault Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Vaults	Underground Vault	EA	-	-	15	$ 3,888,327	-	$ -
Roofs	Underground Vault Roof	EA	2	$ 113,203	5	$ 497,433	2	$ 315,172
UG Network Units	Underground Network Transformers	EA	-	-	36	$ 2,998,417	4	$ 323,468

Table 10: E6.10 Network Unit Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Network Unit (Transformer & Protector)	Underground Network Transformers	EA	43	$ 2,226,623	90	$ 6,191,413	8	$ 587,140

Table 11: E6.13 Station Switchgear Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
TS Switchgear	HONI Contributions		N/A	$ 5,475,623	N/A	$ 2,597,670	N/A	$ -
MS Switchgear	Substation Equipment Air Insulated Switch	EA	-	-	-	-	2	$ 3,426,968

- Note that no TS switchgear were put into service in the time period covered by the table above. The ISA dollars shown for TS switchgear represent lagging HONI contribution expenditures related to previously installed switchgear assets.

Table 12: E6.14 Power Transformer Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
Stations Power Transformer	Substation Transformer	EA	7	$ 3,849,895	1	$ 529,308	4	$ 1,391,540

Table 13: E6.15 Circuit Breaker Renewal

AMPCO Requested Assets	THESL Financial Assets Installed	Unit of Measure	2012 ISA Quantities	2012 ISA Dollars	2013 ISA Quantities	2013 ISA Dollars	As at June 2014 ISA Quantities	As at June 2014 ISA Dollars
KSO Oil Circuit Breakers	Substation Equipment - Outdoor Breaker	EA	3	$ 487,266	5	$ 857,882	1	$ 162,730

E. 2015 Discrete Asset Program Forecasts

Table 14: E6.8 SCADA-Mate R1 Switch Renewal (2015 forecast)

Major Asset Type (Replaced)	2015 Estimated Units	2015 Total Estimated Program Cost
SCADA-Mate R1 Switch	72	$ 6.16 M

- Note that if an obsolete RTU exists at an R1 switch location, the RTU may also be replaced, which will affect the total cost of the R1 replacement. Toronto Hydro estimates that 52 RTUs will be replaced in 2015.

Table 15: E6.9 Network Vault Renewal (2015 forecast)

Major Asset Type (Project Type)	2015 Estimated Units	2015 Total Estimated Program Cost
Network Vault Rebuild	4	$ 2.95 M
Network Vault Roof Rebuild	4	$ 0.70 M
Network Vault Decommissioning	2	$ 0.30 M

- Note that while the Network Vault Renewal program deals with discrete assets, the intervention on those assets will vary depending on requirements. Intervention can include a full vault rebuild, a roof rebuild only, or vault decommissioning. Each planned 2015 project in this program (summarized in Exhibit 2B, Section E6.9, Table 9) corresponds to a particular project type for a discrete unit; as such, Toronto Hydro is able to provide the estimated costs related each type of network vault project in 2015, as shown in the table above.

Table 16: E6.10 Network Unit Renewal (2015 forecast)

Major Asset Type (Replaced)	2015 Estimated Units	2015 Total Estimated Program Cost
Network Units (Transformer & Protector)	40	$ 3.95 M

Table 17: E6.13 Switchgear Renewal (2015 forecast)

Major Asset Type (Replaced)	2015 Estimated Units	2015 Total Estimated Program Cost
MS Switchgear	3	$ 11.9 M
TS Switchgear	0	

Table 18: E6.14 Power Transformer Renewal (2015 forecast)

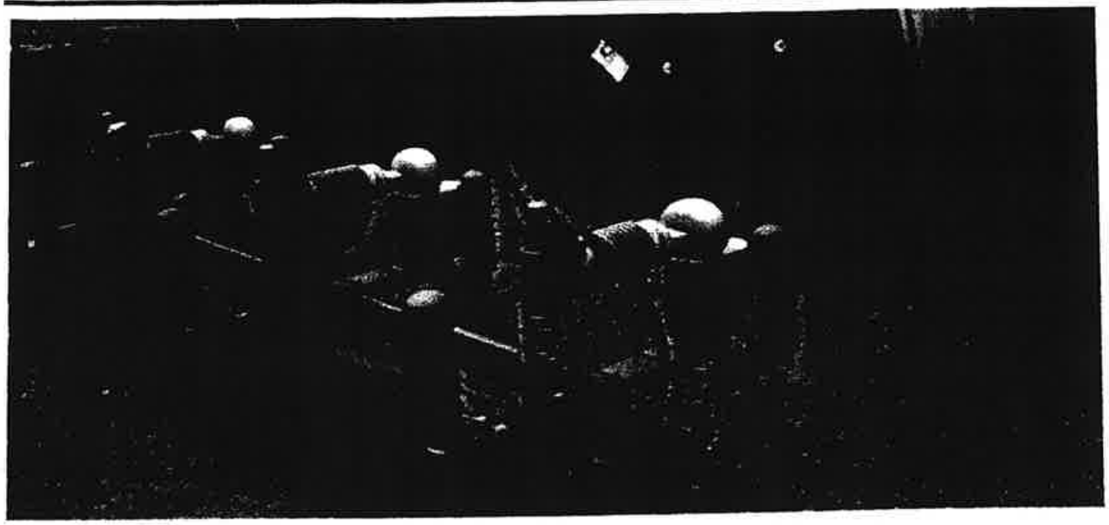
Major Asset Type (Replaced)	2015 Estimated Units	2015 Total Estimated Program Cost
Power Transformer	4	$ 1.68 M

- Please note that the total cost in the table above includes one project for the installation of an oil containment unit at an existing power transformer location. This project is estimated to cost $161 K and will not result in the replacement of a power transformer.

Table 19: E6.15 Circuit Breaker Renewal (2015 forecast)

Major Asset Type (Replaced)	2015 Estimated Units	2015 Total Estimated Program Cost
KSO Oil Circuit Breaker	10	$ 1.66 M

E6.8 SCADA-Mate R1 Switch Renewal



DEFECTIVE SCADA-MATE R1 SWITCH USED FOR INTERNAL INVESTIGATION

E6.8.1 Summary

Program Description

The SCADA-Mate R1 Switch Renewal program will complete the ongoing activities previously described in the Ontario Energy Board (OEB) approved SCADA-Mate R1 Switches segment in the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing.[1]

The SCADA-Mate R1 Switch Renewal program targets the replacement of SCADA-Mate R1 switches which have proven to be defective. There have been three incidents of the switch operating unexpectedly when crews were establishing an open air-gap with the disconnect switch. In one case, this resulted in a flashover and a pole catching fire while a field worker was manually operating the disconnect switch underneath. It has been determined that corrosion of internal components, coupled with the design of the switch, caused the switch to operate unexpectedly. After determining that these switches posed a significant safety hazard (as discussed in section E6.8.3), Toronto Hydro began to replace the SCADA-Mate R1 switches in its system with new R2 switches in 2013.

[1] EB-2012-0064, Tab 4, Schedule B8.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending						Future Spending			
Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CAPEX ($M)	-	-	-	1.90	2.57	6.16	4.11	2.69	-	-

E6.8.2 Program Description

The SCADA-Mate R1 Switch Renewal program will complete the ongoing activities previously described in the OEB-approved SCADA-Mate R1 Switches segment in the Incremental Capital Module (ICM) as part of Toronto Hydro's 2012-2014 rate filing[2]. Toronto Hydro expects to complete the proactive replacement of all in-service SCADA-Mate R1 switches with R2 switches by 2017.

SCADA-Mate switches are overhead load interrupting switches that have the capability of being remotely operated from the control room. The sensory, control and communication functions of these devices provide significant advantages in managing Toronto Hydro's distribution system. For example, SCADA-Mates can detect a fault on a feeder and enable the control room to rapidly isolate the faulted area and restore power to the unaffected areas of the main feeder (also known as the feeder's trunk) by opening and closing the switches remotely. In addition, SCADA-Mate switching units enable Toronto Hydro field crews to create an open isolation point when work is required on a circuit. This is a required and important safety measure to help ensure that the equipment will not become energized while field crews are working on the faulted section of the feeder when restoring a fault in order to create a zone of work protection for the field crews working on the feeder.3

Figure 1 illustrates a typical SCADA-Mate switch configuration, which consists of the switch assembly and the remote terminal unit (RTU). The switch assembly physically connects to the primary conductors to open and close the circuit. SCADA-Mate switches are equipped with SF_6 (sulfur hexafluoride) interrupters that limit and contain any electrical arcing from the interrupter switches. The interrupter indicator on the side of the switch shows whether the switch is in the open or closed position. This allows live circuit making and breaking without exposing Toronto Hydro crews and the public to the risk of arcing and flashovers.

[2] EB-2012-0064, Tab 4, Schedule B8.
[3] Infrastructure Health and Safety Association, *Electrical Utility Safety Rules*, (Mississauga: Infrastructure Health and Safety Association, 2014) at Rule 114 (Safe Conditions for Work), Rule 115 (Work on Isolated Circuits), and Rule 126 (Switching Operations). ["EUSR"]

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

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

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

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
R1 Switch	72	67	57			196
RTU	52	49	14			115

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

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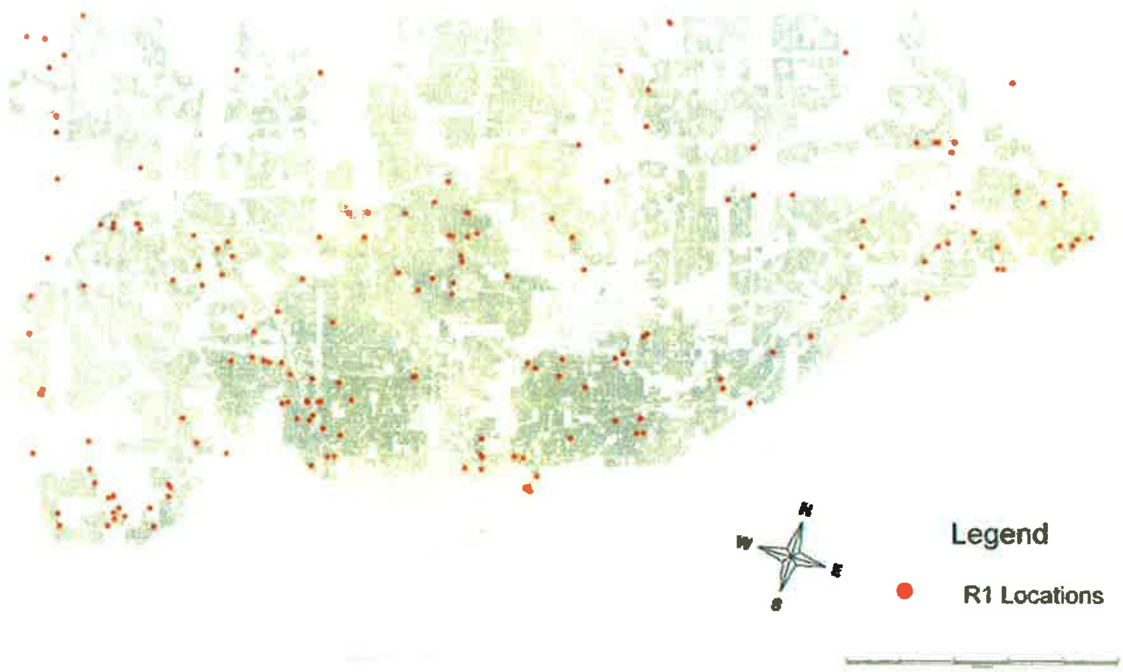

FIGURE 2: MAP OF THE REMAINING SCADA-MATE R1 SWITCHES

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

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

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

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

/C

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

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 39:

Reference(s): **Exhibit 2B, Section E.6 and**
THESL EB-2012-0064, Tab 4, Schedule A, App 1, Tab 1

THESL's DSP has expenditures in the asset categories of System Access, System Renewal, System Service and General Plant. Board staff seeks information that will indicate the degree to which programs authorized in THESL's previous application have been achieved, including the impacts completion of these programs have had on OM&A expenditures, in tabular form including:

a) The objectives which were to be completed in the years 2012 to 2013 (Phase 1) and 2014 (Phase 2, projected) for which capital funding was sought from the Board in EB-2012-0064 according to Reference 2;
b) The total dollars that were sought and approved by the Board, in order to achieve the objective;
c) the capital expenditure (for assets that were actually in-service) that have been spent for the achieved objective;
d) the extent to which the objective was achieved, on a % of dollars basis i.e. "b"/"c";
e) an explanation for the differences where a) the objectives were not achieved or b) where the expenditure, on either a $ per unit or total $expenditure, varied by 10% or more;
f) The OM&A expenditures for the year and how it has been affected by the capital expenditures of earlier years.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

An example of the information Board staff is seeking is provided below for category E6, System Renewal Investments (note that this example only mentions 3 segments of the E6 Assets. All segments for all categories are required):

	Asset	Objective for 2012-2014	Dollars requested	Dollars expended	Achieved	OM&A
E6.1	Underground Circuit Renewal					
	Explanation					
E6.2	PILC Piece-outs and Leakers					
	Explanation					
E6.13	Switchgear Renewal	• Replace 4 obsolete MS switchgear • Replace 4 TS switchgear	Per [Reference 2] Project Schedule B13.1 and 13.2 2012-$19.35m 2013-$18.76m 2014-$20.31m			
	Explanation					
Etc.						

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Please complete the above table and provide similar tables for each of the categories (i.e., System Renewal, System Access, System Service and General Plant) and segments of assets within these categories as shown above.

RESPONSE:

Toronto Hydro has not completed its tracking and analysis of the ICM work program as that program is still being executed. Currently, the following information is available:

- Appendix A provides in-service additions at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). As illustrated in the appendix, Toronto Hydro expects the in-service additions associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall in-service additions.
- Appendix B provides CAPEX at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). Toronto Hydro expects the CAPEX associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall CAPEX.
- Appendix C presents overall CAPEX (actuals) and in-service additions (actuals) for jobs that were listed in approved segments in Phase 1 of the ICM filing (i.e., 2012 and 2013 filed jobs) and that were <u>completed in 2012 or 2013</u>. It compares the sum of the original CAPEX estimates for these jobs versus (i) the sum of the actual CAPEX and (ii) the sum of actual in-service additions associated with the completed jobs. As illustrated, the overall actual spending associated with these jobs has varied by approximately 8% versus overall forecasted spending.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Toronto Hydro is unable to provide an accurate and complete true-up in advance of 2014 year-end close out and a subsequent analysis and reconciliation of segment level spending in each year. There are a number of practical constraints to providing further detailed true-up data in advance of the completion of the 2014 portion of the ICM work program. These result primarily from changes in job timing and composition within ICM segments, coupled with the need to reconcile large amounts of field data.[1] Moreover, as explained in the response to interrogatory 2A-CCC-23, Toronto Hydro believes that providing early or partial true-up information would be inefficient and inconsistent with the OEB's Decision in EB-2012-0064.

There are generally two different types of segments within Toronto Hydro's ICM work program: those that are asset-based (e.g., switchgear), and those that are geographically-based (e.g., underground). For both of these types of work, as jobs move from high-level planning to detailed design and then to execution, their nature and timing may be adjusted. The following situations represent examples of these types of necessary and prudent adjustments.

- *Job scopes change*
    - A detailed field inspection for a geographically-based job, such as an overhead rebuild, may uncover the need for additional asset refurbishment work to be added to the scope of the job.
- *Jobs are advanced and deferred*
    - A field inspection for a geographically-based job such as an overhead rebuild may identify additional assets that require replacement (e.g., more

[1] Toronto Hydro notes that its proposed Enterprise Resource Planning (ERP) system will make improvements to planning capabilities over the current ERP system. For more on the ERP, please see the ERP Program in the DSP, Exhibit 2B Section 8.6.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

poles and transformers), which necessitates additional design work and delays the start date of construction.
  - Feeder loading restrictions imposed due to unusually hot weather may prevent isolation of, or transfer of load to, feeders to allow execution of a job, which necessitates a delay of the job and substitution of another.
- *Jobs are added and deleted from the ICM term*
  - A feeder reconfiguration scheduled during the ICM period may need to be deferred past 2014 because an initially-proposed load transfer was no longer feasible, due to new customer connections resulting in insufficient transfer capacity to undertake the work.
  - A job may need to be added to the ICM program because a new customer could request a connection to the system that would require the expansion and upgrade of an existing transformer. External agencies may require relocation of Toronto Hydro plant to allow for execution of their own work, resulting in the addition of a job to the program and forcing the deferral of another or others.
  - Poor asset performance with a resultant impact on reliability in a given area may require the addition or advancement of a job to the work program, forcing the deferral of another or others.

Toronto Hydro is diligently tracking these changes to the ICM program and intends to provide the OEB and intervenors with a specific reconciliation of forecasts versus actual, including detailed explanations for variance, through the true-up process. However, due to ongoing reconciliation activities and the number of personnel working on the capital program as it moves from planning to detailed design to execution, the detailed information that the utility currently has is in the form of a large amount of field data that

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

has not yet been reviewed, compiled, and summarized such that it can be effectively presented. Only once the full ICM program is complete, 2014 financial closeout has occurred and all field data is gathered, will Toronto Hydro be able to begin undertaking the compilation exercise, which it expects to present to the OEB in the second quarter of 2015.

APPENDIX A: Capital Summary Table (ISAs)

		Phase 1: Approved			Phase 2: Approved	Phase 1 + 2: Approved		Phase 1 + 2: Actual/Forecast					Variance	
		In-Service Additions												
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
Schedule Number	Segments	Total 2012 In-Service Additions	Total 2013 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total Approved In-Service Additions (2012-2014)	2012 In-Service Additions Actual (Annual)	2013 In-Service Additions Actual (Annual)	2014 In-Service Additions Actual (YTD June)	2014 In-Service Additions Forecast (Annual)	Total Forecast In-Service Additions (2012-2014)	Total 2014 In-Service Additions Approved vs Forecast	Total 2012-2014 In-Service Additions Approved vs Forecast
B1	Underground Infrastructure	12.74	51.88	23.07	36.70	59.77	124.39	9.35	62.17	10.07	76.54	148.06	16.78	23.67
B2	Paper Insulated Lead Covered Cable Piece Outs and Leakers	0.04	3.34	2.12	1.42	3.54	6.92	0.11	0.15	0.38	6.17	6.44	2.63	(0.48)
B3	Handwell Replacement	6.05	17.73	6.52	7.22	13.74	37.53	5.41	16.61	2.34	10.89	32.92	(2.85)	(4.60)
B4	Overhead Infrastructure	4.02	39.06	21.87	14.78	36.65	79.73	1.03	33.47	12.86	49.82	84.32	13.17	4.59
B5	Box Construction	0.26	14.35	9.02	5.72	14.74	29.34	0.02	5.24	2.90	18.45	23.71	3.71	(5.64)
B6	Rear Lot Construction	7.25	27.02	11.52	5.00	16.52	50.79	3.49	27.23	8.35	16.70	47.42	0.18	(3.37)
B9	Network Vault & Roofs	1.26	13.00	7.34	0.90	8.24	22.50	-	12.33	2.05	2.29	14.62	(5.95)	(7.88)
B10	Fibertop Network Units	0.65	5.52	3.02	2.84	5.85	12.02	0.96	7.06	0.94	5.60	13.62	(0.25)	1.60
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	1.99	1.28	0.10	1.38	3.36	-	1.51	0.29	0.30	1.81	(1.08)	(1.55)
B12	Stations Power Transformers	0.17	2.33	1.36	-	1.36	3.86	-	0.35	0.99	2.90	3.25	1.54	(0.60)
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	0.77	9.16	5.37	1.41	6.78	16.71	-	-	3.21	3.61	3.61	(3.17)	(13.10)
B20	Metering	2.10	7.75	3.29	3.82	7.11	16.96	-	7.13	3.41	10.82	17.95	3.72	0.99
B21	Externally-Initiated Plant Relocations and Expansions	4.50	20.78	9.72	1.87	11.59	36.87	1.94	7.37	0.03	17.80	27.10	6.21	(9.77)
BXX	ICM Understatement of Capitalized Labour	3.69	4.63	-	-	-	8.32	-	-	-	-	-	-	(8.32)
[redacted]														
B17	Copeland Transformer Station	-	-	124.10	-	124.10	124.10	-	2.08	1.30	1.30	3.38	(122.80)	(120.72)
B18.2	Hydro One Capital Contributions	-	-	60.00	-	60.00	60.00	-	-	-	-	-	(60.00)	(60.00)
[redacted]														
B7	Polymer SMD-20 Switches	-	0.93	0.60	1.59	2.19	3.12	-	0.84	-	1.51	2.35	(0.68)	(0.77)
B8	SCADA-Mate R1 Switches	-	0.87	0.56	1.89	2.45	3.32	-	1.88	0.03	0.03	1.91	(2.43)	(1.42)
B14	Stations Circuit Breakers	0.34	0.76	0.22	1.05	1.27	2.36	0.22	0.90	0.19	0.50	1.62	(0.77)	(0.74)
B16	Downtown Station Load Transfers	0.30	1.68	0.84	-	0.84	2.82	-	0.03	1.33	1.33	1.36	0.49	(1.46)
B18.1	Hydro One Capital Contributions	-	1.48	-	2.64	2.64	4.12	5.48	2.61	-	1.76	9.85	(0.88)	5.73
C1	Operations Portfolio Capital	29.00	87.75	29.66	49.29	78.95	195.70	39.93	79.39	30.76	99.43	218.76	20.48	23.05
C2	Information Technology Capital	9.25	21.47	6.28	11.25	17.53	48.25	7.56	20.28	6.24	17.49	45.33	(0.04)	(2.92)
C3	Fleet Capital	0.29	0.76	1.75	2.00	3.75	4.80	0.80	0.44	1.83	3.72	4.96	(0.03)	0.16
C4	Buildings and Facilities Capital	3.76	2.90	3.35	5.00	8.35	15.00	1.40	6.16	0.04	7.21	14.77	(1.13)	(0.23)
[redacted]														

APPENDIX B: Capital Summary Table (CAPEX)

		Phase 1: Approved Capital Spending			Phase 2: Approved Capital Spending	Total Phase 1 + 2 Capex Approved		Phase 1 + Phase 2: Actual/Forecasted Capital Spending					Variance	
		CapEx			CapEx	CapEx	CapEx	CapEx						
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
Schedule Number	Segments	2012 Approved Capex	2013 Approved Capex	2014 Approved Capex	Total 2014 Approved Capex	Total 2014 Approved Capex	Total Approved Capex (2012-2014)	2012 Capex (Actual)	2013 Capex (Actual)	2014 Capex Actual (YTD Jun)	2014 Capex IR Fcst as at Jul 2014 (Annual)	Total Fcst Capex (2012-2014)	Total 2014 Capex Approved vs Fcst	Total 2012-2014 Capex Approved vs Fcst
B1	Underground Infrastructure	28.75	58.94	-	77.86	77.86	165.56	36.90	55.97	41.69	107.08	199.95	29.22	34.39
B2	Paper Insulated Lead Covered Cable - Piece Outs and Leakers	0.08	5.42	-	3.55	3.55	9.05	0.14	1.98	2.33	5.96	8.08	2.42	(0.96)
B3	Handwell Replacement	13.65	16.65	-	18.06	18.06	48.36	12.39	11.87	3.96	15.52	39.77	(2.54)	(8.59)
B4	Overhead Infrastructure	9.07	55.88	-	26.01	26.01	90.96	11.59	40.42	28.23	64.12	116.13	38.10	25.16
B5	Box Construction	0.58	23.04	-	14.27	14.27	37.90	0.84	13.84	9.70	23.03	37.71	8.76	(0.18)
B6	Rear Lot Construction	16.36	29.43	-	12.51	12.51	58.29	15.98	23.20	7.35	26.42	65.60	13.91	7.31
B9	Network Vault & Roofs	2.84	18.76	-	2.25	2.25	23.85	2.81	10.58	1.17	1.18	14.58	(1.07)	(9.27)
B10	Fibertop Network Units	1.48	7.71	-	7.09	7.09	16.28	2.14	6.83	1.59	4.66	13.63	(2.43)	(2.65)
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	3.26	-	0.25	0.25	3.51	-	1.59	0.22	0.22	1.81	(0.03)	(1.70)
B12	Stations Power Transformers	0.38	3.48	-	-	-	3.86	0.02	1.54	0.87	2.66	4.21	2.66	0.36
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	1.73	13.72	-	3.54	3.54	18.98	2.43	5.08	3.21	9.34	16.85	5.81	(2.13)
B20	Metering	4.74	8.40	-	9.54	9.54	22.68	5.69	4.72	4.91	12.56	22.97	3.02	0.29
B21	Externally-Initiated Plant Relocations and Expansions	10.16	24.84	-	4.55	4.55	39.55	9.20	18.57	3.87	6.46	34.23	1.91	(5.33)
BXX	ICM Understatement of Capitalized Labour	8.32	-	-	-	-	8.32	-	-	-	-	-	-	(8.32)
[redacted]														
B17	Copeland Transformer Station	8.50	81.00	34.60	-	34.60	124.10	4.07	26.72	20.57	54.51	85.29	19.91	(38.81)
B18.2	Hydro One Capital Contributions	-	23.00	37.00	-	37.00	60.00	-	18.60	8.85	21.20	39.80	(15.80)	(20.20)
[redacted]														
B7	Polymer SMD-20 Switches	-	1.53	-	3.97	3.97	5.50	-	0.84	0.71	1.85	2.69	(2.13)	(2.82)
B8	SCADA-Mate R1 Switches	-	1.43	-	4.73	4.73	6.16	-	1.90	0.45	1.79	3.69	(2.94)	(2.47)
B14	Stations Circuit Breakers	0.76	0.55	-	2.63	2.63	3.94	0.22	1.02	0.09	1.81	3.05	(0.82)	(0.89)
B16	Downtown Station Load Transfers	0.68	2.14	-	-	-	2.82	0.05	2.31	0.42	1.29	3.65	1.29	0.84
B18.1	Hydro One Capital Contributions	1.48	-	-	2.64	2.64	4.12	26.63	20.49	1.04	5.88	53.00	3.24	48.88
C1	Operations Portfolio Capital	64.78	81.63	-	103.78	103.78	250.19	66.67	93.24	41.61	98.24	258.15	(5.53)	7.96
C2	Information Technology Capital	22.00	15.00	-	15.00	15.00	52.00	23.20	17.12	5.99	16.24	56.57	1.24	4.57
C3	Fleet Capital	0.80	2.00	-	2.00	2.00	4.80	0.79	2.16	0.51	2.00	4.95	-	0.15
C4	Buildings and Facilities Capital	5.00	5.00	-	5.00	5.00	15.00	5.13	5.71	1.35	8.25	19.10	3.25	4.10
	Allowance for Funds Used During Construction	1.20	1.40	-	7.95	7.95	10.55	-	-	-	-	-	(7.95)	(10.55)
[redacted]														

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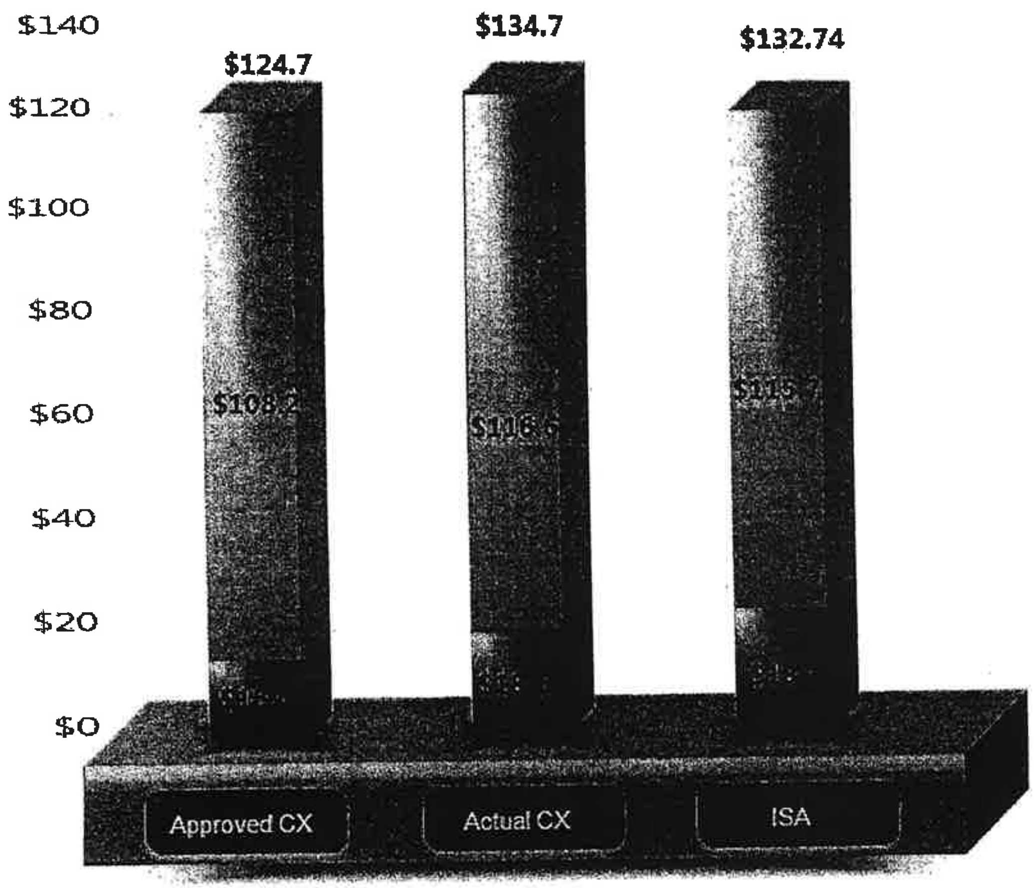
APPENDIX C: Phase 1 ICM Jobs Completed in 2012-2013

Filed ICM Phase 1 Jobs Completed in 2012-2013 ($ millions)
Approved CAPEX, actual CAPEX and actual in-service amount (ISAs)



Completed in 2012

Completed in 2013

Note 1:
This summary represents 188 jobs filed in approved ICM segments in Phase 1.

Note 2:
This summary excludes Copeland TS and HONI capital contributions.

Note 3:
Minor revisions to these amounts are anticipated based on further reconciliation of financial data for 2013 jobs.

ICM Project – Underground Infrastructure and Cable

Underground Infrastructure Segment

Toronto Hydro-Electric System Limited (THESL)

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SUMMARY OF CHANGES IN THE UPDATE

- Reduced 2012-2013 budget from $99.96 M to $87.7 M, a reduction of $12.26 M
- Revised number of jobs proposed for 2012/2013 to 27, with jobs for 2014 to be addressed in Phase Two, as proposed
- 2014 jobs and spending shown in strike-through
- Restructured 2012 and 2013 jobs to recognize the work accomplished to date in 2012 and the continuing priority needs of the system
- Clarified the trend in outages due to direct buried cable by presenting the information in terms of outages per kilometre of direct buried cable remaining in the system. See Figure 1
- Corrected numerical and typographical errors

ICM Project | Underground Infrastructure Segment

I EXECUTIVE SUMMARY

1. Project Description

This segment includes 27 discrete jobs to replace approximately $87.7 million of direct buried /UF, US cable with cable in concrete-encased ducts, and air-insulated pad-mounted switchgear units with SF_6-insulated pad-mounted switchgear units in 2012~~,~~ and 2013~~, and 2014~~. The cost breakdown by year is $61.1 million in 2012~~,~~ and $26.6 million in 2013~~, and $74.92 million in 2014~~. The jobs address both direct buried cable and air-insulated pad-mounted switchgear units /UF, US collectively, as this is the most efficient and cost-effective approach. Table 1 below lists the proposed jobs, in order of the number of unplanned sustained outages[1] experienced by the feeder in 2011 (with the exception of the last job in the table because it addresses a number of feeders). Each job is described in section II.

Table 1: List of jobs to be executed in 2012~~,~~ and 2013 ~~and 2014~~

Job Title	Year	Estimated Cost ($M)	
Underground Rehabilitation of Feeder NY80M29	2012, 2013	$2.90	
Underground Rehabilitation of Feeder SCNAR26M34	2012, 2013~~, 2014~~	$2.33	/US
Underground Rehabilitation of Feeder NY55M8	2013	$2.50	/UF, US
Underground Rehabilitation of Feeder YK35M10	2012	$2.32	/US
~~Underground Rehabilitation of Feeder SCNT63M4~~	~~2014~~	~~$3.16~~	
Underground Rehabilitation of Feeder SCNA47M14	2012, 2013	$4.43	
Underground Rehabilitation of Feeder NY51M6	2012	$2.91	/UF, US
~~Underground Rehabilitation of Feeder NY80M8~~	~~2014~~	~~$9.51~~	
~~Underground Rehabilitation of Feeder NY85M6~~	~~2014~~	~~$2.01~~	
Underground Rehabilitation of Feeder NY51M8	2013~~, 2014~~	$1.26	/US
Underground Rehabilitation of Feeder SCNA502M22	2012, 2013~~, 2014~~	$2.78	/UF, US

[1] A sustained outage is an outage lasting more than one minute.

ICM Project | Underground Infrastructure Segment

Job Title	Year	Estimated Cost ($M)	
Underground Rehabilitation of Feeder SCNAH9M30	2012, ~~2014~~	$0.84	/UF, US
Underground Rehabilitation of Feeder NY85M4	2013, ~~2014~~	$2.48	
Underground Rehabilitation of Feeder SCNA47M13	2012, ~~2013, 2014~~	$3.47	
Underground Rehabilitation of Feeder NY80M2	2012	$0.80	/UF
Underground Rehabilitation of Feeder NY51M7	2013	$1.43	
Underground Rehabilitation of Feeder NY51M24	2013, ~~2014~~	$3.21	/US
Underground Rehabilitation of Feeder NY80M30	2012	$4.07	/UF
~~Underground Rehabilitation of Feeder NY55M23~~	~~2014~~	~~$2.24~~	
~~Underground Rehabilitation of Feeder NY85M24~~	~~2014~~	~~$2.03~~	/US
Underground Rehabilitation of Feeder SCNAE5-2M3	2012	$1.51	
~~Underground Rehabilitation of Feeder NY85M7~~	~~2014~~	~~$13.83~~	
Underground Rehabilitation of Feeder SCNT63M12	2012, 2013, ~~2014~~	$7.68	/UF, /US
Underground Rehabilitation of Feeder SCNT63M8	2012, 2013, ~~2014~~	$5.05	
Underground Rehabilitation of Feeder SCNAE5-1M29	2012	$3.97	
Underground Rehabilitation of Feeder NY53M25	2013	$2.40	/US
~~Underground Rehabilitation of Feeder NY80M9~~	~~2014~~	~~$2.21~~	
Underground Rehabilitation of Feeder SCNT47M3	2012, 2013, ~~2014~~	$16.98	/UF, /US
~~Underground Rehabilitation of Feeder SCNAH9M23~~	~~2014~~	~~$2.71~~	
Underground Rehabilitation of Feeder NY51M3	2012, 2013, ~~2014~~	$0.37	/UF, /US
Underground Rehabilitation of Feeder SCNA47M17	2012	$1.10	
Underground Rehabilitation of Feeder NY85M31	2013	$0.34	/UF
~~Underground Rehabilitation of Feeder SCNA502M21~~	~~2014~~	~~$2.56~~	
Underground Rehabilitation of Feeder SCNT47M1	2012, 2013, ~~2014~~	$6.63	/UF, /US
Underground Rehabilitation of Feeder NY55M21	2013	$1.51	/UF
Underground Rehabilitation of Feeders NY85M1, NY85M9 and NYSS58F1	2012, 2013	$2.66	/US
	Jobs Total	$87.63	
Reconciliation for job cost changes < $100,000 and rounding		$ 0.07	
	Reconciled Total	$87.70	

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TABLE 7: AVOIDED RISK COST BUSINESS CASE EVALUATION

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

E6.1.7 2015 Project Details

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

(a) previously filed projects that appeared as jobs in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

ICM Jobs	CIR Projects
14.0	82.0

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

TABLE 7: AVOIDED RISK COST BUSINESS CASE EVALUATION

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

E6.1.7 2015 Project Details

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

(a) previously filed projects that appeared as jobs in the OEB approved Underground Infrastructure segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 8: 2015 PROGRAM COSTS

ICM Jobs	CIR Projects
18.6	77.3

/C

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

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TABLE 9: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E11628	E11628 Morningview UG Rebuild Phase 1 - Elec (47M3)	$344,403	2014	ICM
E11629	E11629 Morningview UG Rebuild Phase 2 - Elec (47M3)	$574,005	2014	ICM
E11803	E11803 Rebuild feeder egress H9M32 and M26 Ellesmere-Civil	$770,354	2015	CIR
E12128	E12128 Morningview UG Rebuild Phase 3 -Civil(47M3)	$1,607,213	2014	ICM
E12210	E12210 - Venture Drive UG SCNT47M1 - Civ / Elec	$1,838,314	2015	ICM
E12213	E12213 - Morningside Casebridge SCNT47M1 - Elec	$1,963,487	2015	ICM
E12217	E12217 Windfield Bayview Area Rebuild (51M21, NYSS27F1)	$172,201	2014	ICM
E12243	E12243 Durnford-Rylander-Tideswell Rebuild ph2 Electrical (47M17)	$57,400	2014	ICM
E12244	E12244 Tallpine Rebuild Phase Electrical (47M17)	$688,805	2014	ICM
E12251	E12251 Scenic Millway Rebuild SS27 - Electrical	$1,722,014	2014	ICM
E12267	E12267 Clappison Rebuild Electrical (47M17)	$229,602	2014	ICM
E12278	E12278 Nashdene-Tiffield UG Rebuild - Elec (NAR26M22) (DESIGN ONLY)	$3,628,734	2015	CIR
E12302	E12302 McNicoll Maybrook SCNAR26M32 UG Rebuild – Civil	$1,378,994	2015	CIR
E12310	E12310 Scunthorpe Invergordon UG Rebuild Ph A - Civil H9M26 SCNAH9M26	$1,273,978	2015	CIR
E12311	E12311 Scunthorpe Invergordon UG Rebuild Ph A - Electrical H9M26 SCNAH9M26	$739,958	2015	CIR
E12324	E12324 Dynamic Dr/McNicoll - Electrical (NAR26M32)	$919,012	2015	CIR
E12331	E12331 Civil Works for Rebuild of NYSS38F2 off Bunty Lane NYSS38F2	$51,856	2015	CIR
E12346	E12346 Bluffwood Saddletree Electrical NY51M3	$124,286	2015	ICM
E12380	E12380 Rebuild of NY51M4 Consumers Rd & Victoria Park Areas - Electrical NY51M4	$1,540,160	2015	CIR
E12385	E12385 Don Mills / Eglinton Rebuild - Civil (53M1)	$131,366	2015	ICM

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E12386	E12386 Don Mills / Eglinton Rebuild - Electrical (53M1)	$285,129	2015	ICM
E12400	E12400 Cass Ave UG VC NHF3 to 502M22 - Civil SCNHF3	$2,247,023	2015	CIR
E12406	E12406 Palmdale Dr UG VC NHF3 to 502M22 - Civil SCNHF3	$1,203,205	2015	CIR
E12409	E12409 Thimble Berryway Aspenwood UG Rebuiild Electrical NY51M3	$206,194	2015	ICM
E12428	E12428 Rebuild of NY51M4 Consumers Rd & Victoria Park Areas - Civil NY51M4	$342,386	2015	CIR
E12430	E12430 Cherrystone Aspenwood - Electrical (51M27)	$166,171	2015	ICM
E12477	E12477 Middlefield Passmore StateCrown Civil SCNAR26M21	$1,403,077	2015	CIR
E12487	E12487 Middlefield Industrial UG 63M6 Rebuild-Civil SCNT63M6	$859,191	2015	CIR
E13041	E13041 Ironside Crescent UG Rebuild Civil SCNAR26M21	$953,041	2015	ICM
E13046	E13046 NY53M26 UG Rebuild in Curlew and Victoria Park areas – Civil	$348,912	2015	CIR
E13065	Rebuild of SCNAE5-1M25 by Brimley Rd and Skagway Avenue – Electrical	$392,239	2015	ICM
E13069	E13069 NY51M24 UG Rebuild North of Finch	$430,208	2014	ICM
E13194	E13194 off Don Mills/Graydon Hall UG Reh (NY51M29)	$2,066,416	2014	ICM
E13212	E13212 Teesdale Place UG Reb Civil (SCNAR43M27)	$240,432	2015	CIR
E13240	E13240 51M22, 51M4 UG rehab off Sheppard & Victoria Park Intersection-Civil	$633,781	2015	CIR
E13621	Brandy Court PandC Civil Elec NY53M24	$113,533	2015	CIR
E13673	E13673 FESI mitigation 47M13 submersible transformer SCNA47M13	$75,664	2015	CIR
E14008	E14008 Rebuild Trunk 502M1 M22 Birchmount – Electrical	$362,801	2015	CIR
E14035	E14035 Teesdale Place UG Rebuild Electrical SCNAR43M27	$360,264	2015	CIR
E14116	E14116 DB Cable Replacements on SS63F1-Cummer & Maxome area-Civil	$262,347	2015	CIR
E14141	E14141 UG Rebuild 502M32 Eastwood SD- Civil	$1,442,504	2015	CIR
E14160	E14160 UG Cable Replacement 53M25 Cassandra 3Ph	$408,725	2015	CIR

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Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
E14177	E14177 UG Rebuild 502M29 Carabob Crt - Civil	$415,952	2015	CIR
E14179	E14179 UG Rebuild 502M29 Bonis King Henrys- Civil	$936,238	2015	CIR
E14191	E14191 UG Rebuild H9M30 Kingston Mason -Electrical	$623,791	2015	CIR
E14230	E14230 Manse Road 209-245 UG Rebuild Civil	$744,400	2015	CIR
E14234	E14234 Grenoble Gateway UG Rebuild Civl NY53M9	$297,997	2015	CIR
E14236	E14236 185 Galloway UG Rebuild SCNAH9M29 - Civil	$457,867	2015	CIR
E14281	E14281 UG Rebuild VC 64F2 to 51M5 Argonne Simeon- Civil	$1,175,981	2015	CIR
E14322	E14322 Establish Neilson Tapscott R26M34 Main – Electrical	$737,921	2015	ICM
E14411	E14411 Crow Tr Remaining UG Rebuild Civ and Elect R26M34 SCNAR26M34	$473,989	2015	CIR
E14432	E14432 P01 47M1 Mammoth Hall UG Rebuild Ph3 (Electrical) SCNT47M1	$855,398	2015	ICM
E15024	E15024 P01 Sheppard UGDB Cable Reb Ele	$429,796	2015	CIR
E15193	E15193 Leslie-Clovercrest-UG Renewal-Civil & Elec-51M6 NY51M6	$540,298	2015	CIR
E15195	E15195 Morningside Ave UG trunk-Civil NT47M3 SCNT47M3	$431,057	2015	CIR
E15197	E15197 P01-Finch-Sheppard-Replacement 51M22 trunk-Elec-51M22-Leslie Ts	$539,483	2015	CIR
E15198	E15198 Finch-Sheppard-trunk cable repl.-Elec- 51M28 NY51M28	$476,680	2015	CIR
E15231	E15231 Leslie/Finch Replace UG cable 51M23 NY51M23	$137,417	2015	CIR
E15232	E15232 Leslie/Finch Replace UG trunk cable 51M7 NY51M7	$123,896	2015	CIR
E15233	E15233 Woody Vineway & Curly Vineway UG renewal 51M6 NY51M6	$290,478	2015	CIR
E15267	E15267 -P162 Bermondsey Trunk UG Renewal Elec 53M2, M12, M27, M28 NY	$1,687,487	2015	CIR
E15270	E15270 Victoria Park Gordon Baker UG renewal Phase II Civil 51M32 NY51M3	$1,456,519	2015	CIR
E15273	E15273 Wynford Heights Crescent UG Renewal Elec NY53M2	$378,823	2015	CIR
E15306	E15306 Leslie Francine Gideon Conversion Civil SS68-F10 to 51M3	$2,695,018	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
	NYSS68F1			
E15307	E15307 Bridgeport UG Rebuild Ph1 - Civil 47M13 SCNA47M13	$1,896,861	2015	CIR
E15316	E15316 Leslie Threadneedle Clansman Conversion SS68F10 to 51M3 NYSS68F10	$501,360	2015	CIR
E15317	E15317 Bridgeport UG Rebuild Ph2 - Civil 47M13 SCNA47M13	$1,853,593	2015	CIR
E15318	E15318 Bridgeport UG Rebuild Ph3 - Civil 47M13 SCNA47M13	$1,943,271	2015	CIR
E15324	E15324 Paul Markway Conversion Civil SS68-F10 to 51M27 NYSS68F10	$559,217	2015	CIR
E15325	E15325 Paul Markway Conversion Elec SS68-F10 to 51M27 NYSS68F10	$123,755	2015	CIR
E15328	E15328 McNicoll Leslie Conversion Civil SS68F10 to 51M3 NYSS68F10	$2,933,082	2015	CIR
E15332	E15332 Guildpark Pathway UG Rebuild - Civil H9M30 SCNAH9M30	$401,734	2015	CIR
E15342	E15342 Tahoe Court UG Rebuild Civil NY53M24	$243,928	2015	CIR
E15350	E15350 Confederation Angora UG Rebuild - Civil H9M30 SCNAH9M30	$2,007,342	2015	CIR
E15353	E15353 Brahms Clansman Don Mills Conversion Civil SS68-F1 to 51M27	$569,495	2015	CIR
E15355	E15355 Gracemount UG Rebuild - Civil H9M30 SCNAH9M30	$975,476	2015	CIR
E15356	E15356 Gracemount UG Rebuild - Electrical H9M30 SCNAH9M30	$340,470	2015	CIR
E15379	E15379 Victoria Park York Mills UG cable replacement 51M25 NY51M25	$817,406	2015	CIR
E15390	E15390 Scunthorpe Invergordon UG Rebuild Ph B - Civil H9M26 SCNAH9M26	$1,466,283	2015	CIR
E15392	E15392 Scunthorpe Invergordon UG Rebuold Ph D - Civil H9M26 SCNAH9M26	$1,737,054	2015	CIR
E15393	E15393 Scunthorpe Invergordon UG Rebuild Ph E - Civil H9M26 SCNAH9M26	$761,102	2015	CIR
E15395	E15395 Consumers Rd Sheppard UG Renewal 51M28 NY51M28	$929,773	2015	CIR
E15397	E15397 Scunthorpe Invergordon UG Rebuild Ph G- Civil H9M26 SCNAH9M26	$900,235	2015	CIR
E15429	E15429 Bridletowne-Warden 1-Ph UG	$1,738,101	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
	Rehab Civ SCNA502M22			
E15442	E15442 McGrisken Rd UG Rebuild - Electrical H9M23 SCNAH9M23	$180,272	2015	CIR
E15445	E15445 Cromwell Senator UG Rebuild - Civil 47M14 SCNA47M14	$1,594,380	2015	CIR
E15476	E15476 45 Birchmount Road UG Rebuild Civil SCNAR43M24	$88,288	2015	CIR
E15477	E15477 45 Birchmount UG Rebuild Elec SCNAR43M24	$97,275	2015	CIR
E15558	E15558 Bridletown-Warden 3-Ph UG Rehab Civ SCNA502M22	$97,275	2015	CIR
E15587	1123 Leslie St at Eglinton UG cable replacement 34M5	$32,837	2015	CIR
E16071	E16071 Morningside Ave UG trunk Electrical NT47M3 SCNT47M3	$409,540	2015	CIR
E16110	E16110 Guildpark Pathway UG Rebuild - Electrical H9M30 SCNAH9M30	$318,278	2015	CIR
E16131	E16131 Scunthorpe Invergordon UG Rebuild Ph D - Electrical H9M26 SCNAH9M26	$556,505	2015	CIR
W11156	35M10, M2, M4 & M9 Fairbank TS PILC Cable Replacmnt (Revised)	$826,754	2015	CIR
W11161	W11161 35M9 Fairbank TS PILC Cable Replacmnt	$74,025	2015	CIR
W11170	W11170 35M4 Fairbank TS PILC Cable Replacmnt	$215,957	2015	CIR
W11287	W11287 FESI - NY55M22 - Lateral Cable Replacmnt - Rowntree (ph4)	$718,430	2015	CIR
W11288	W11288 FESI 55M22 LATERAL CABLE REPLACEMENT-ISLINGTON	$332,907	2015	CIR
W12077	Hoggs Hollow PH4	$1,722,014	2013	ICM
W12308	W12308 FESI Clubhouse Crt and Brookwell Dr Rebuild	$1,290,728	2015	CIR
W12480	W12480 Primary Trunk Cable Replacement-The East Mall	$585,421	2015	CIR
W13114	W13114 Trunk Cable Replacement-The East Mall-ETHL-F2/F4	$597,047	2015	CIR
W13284	W13284 UG Lateral Repalcement Phase 1	$1,509,954	2015	CIR
W13287	W13287 UG Lateral Repalcement Phase 2	$1,951,438	2015	CIR
W14130	Rebuild Russfax & Twin Circle Crt	$439,236	2015	CIR
W14217	UG Lateral Cable Replacement - Signet/Kenhar 55M1	$1,063,379	2015	CIR

Project Number	Project Name	Total Project Cost	Start Date	Project Type (ICM or CIR)
W14274	UG Lateral Cable Replacement - Fenmar/Ormout 55M1	$1,055,354	2015	CIR
W14653	W14653-P01-Richview Feeder Egress Via Kelfield Rd	$1,341,461	2015	ICM
W14730	W14730-P01-Cable Upgrade to Increase Capacity on 88M46	$116,478	2015	CIR
W15268	W15268 - P01 - Red Robinway & Arnott UG Direct-Buried Cable Renewal CIVIL	$507,205	2015	CIR
W15269	W15269 - P01 - Red Robinway & Arnott UG Direct-Buried Cable renewal ELEC	$578,936	2015	CIR
W15278	W15278 The East Mall area UG Voltage Conversion Civil LDF1, LDF2 and LDF3 LDF1	$622,916	2015	CIR
W15279	W15279 - Dundas/Shaver area UG VC Civil QCF1, QCF2 and QCF3	$617,408	2015	CIR
W15298	W15298 West of Kipling Avenue, UG Voltage Conversion AHF2, AHF5	$573,753	2015	CIR
W15357	W15357 270 The Kingsway, Upgrade PT44103 Humbertown Plaza, 38M7 38-M7	$208,386	2015	CIR
W15363	W15363 150 Berry Rd VC of Tx/Sw at loc PT7257 to feeder 38M29 T-F1	$386,009	2015	CIR
W15462	W15462 Alcester Crt Underground Rebuild 35M7	$304,772	2015	CIR
W16076	W16076 - P01 Mayall Avenue Underground Rebuild 55M26	$564,185	2015	CIR
X12138	X12138 Larksong Crt Feeder DB Cable Replace (53M8) (DESIGN ONLY)	$240,187	2015	CIR
X12497	X12497 - Lotherton Parkway UG reconfiguration NY35M12	$880,289	2015	CIR
X15590	Electrical Work for the Replacement of A60CS and A61CS	$72,565	2015	CIR

The following subsections provide project details for all 2015 projects.

THESL APPROACH

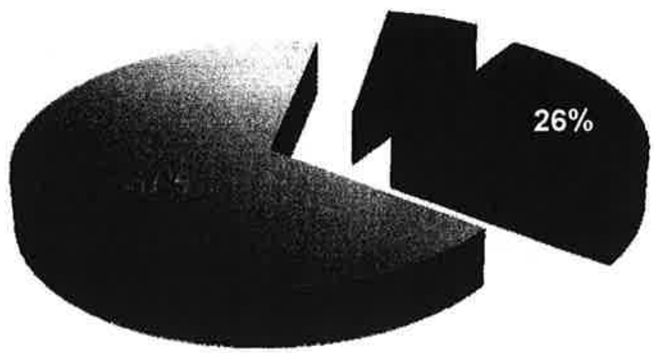


FIGURE 8: USEFUL LIFE DEMOGRAPHICS – 2015

It is critical that Toronto Hydro is able to manage this backlog as per a capital investment approach and execution strategy that allows for the steady state to be achieved, while also being responsive to customer's price sensitivity and practical to execute when accounting for available resources. The following sections provide further details and breakdowns on the capital investment approach as well as the execution strategies that may be applied in order to eliminate this backlog.

E2.1.2 Capital Investment Approach

The first milestone of the long-term system review process is to derive a proactive capital investment approach. Toronto Hydro's capital investment approach produced as part of the 2015-2019 capital expenditure plan includes three forms of investments:

- Asset renewal investments designed to target those assets nearing, at or beyond their economic end-of-life or end-of-useful life criteria within Toronto Hydro's grid systems (overhead, underground, secondary network, stations).
- System-wide critical issues that are of utmost urgency and go "beyond the asset", introducing challenges associated with safety, operational and capacity constraints, security of supply and load growth.

system plan itself that is supplied by outputs from the planning process, and finally (v) a measurement and enhancement process that supports continuous improvement. Figure 12 depicts the AM process and its various elements and support systems.

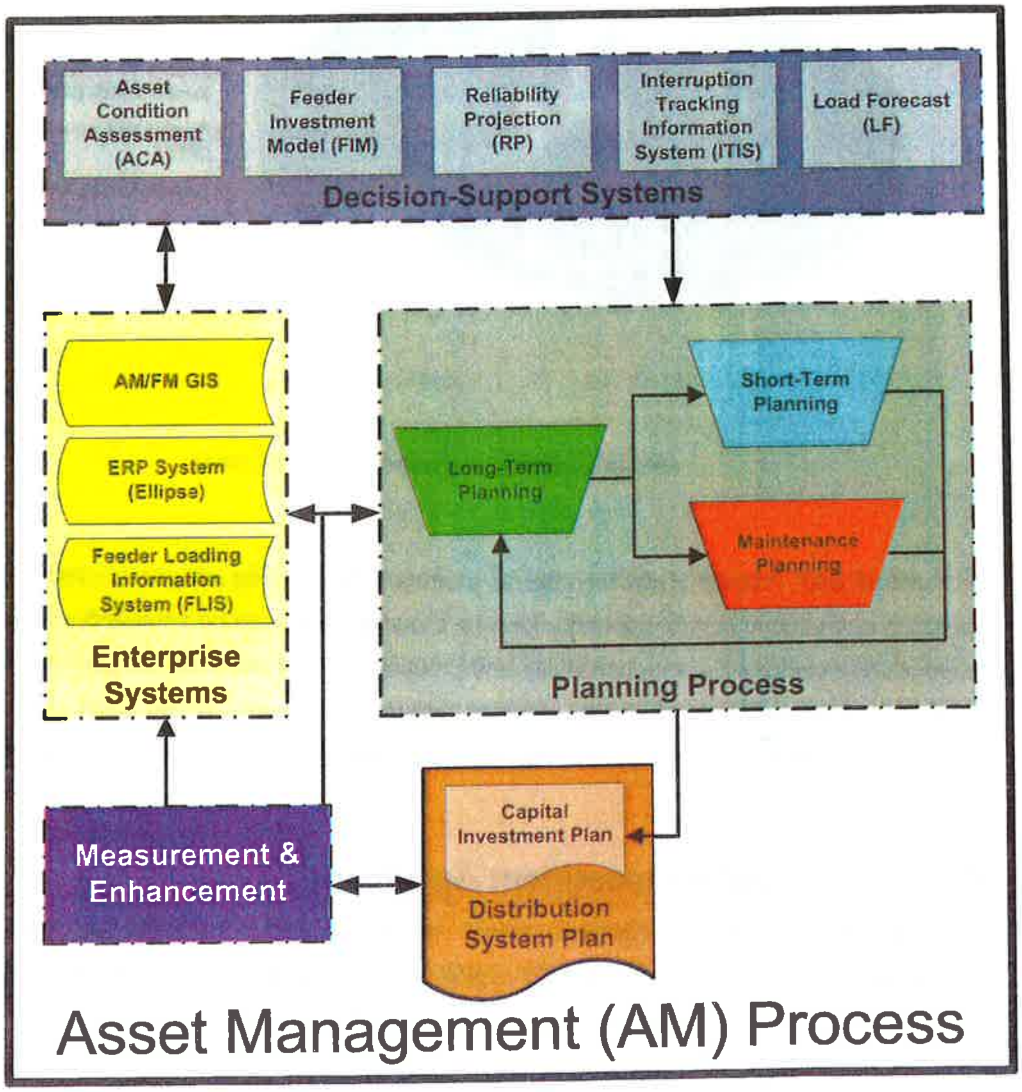


FIGURE 12: ASSET MANAGEMENT PLANNING PROCESS OVERVIEW

The planning process element of the AM process can be further subdivided into three stages:

(i) Long-term planning, discussed in detail in Section D1.2.1, results in the development of a capital investment approach and execution strategy along with corresponding investment programs that align to AM objectives.

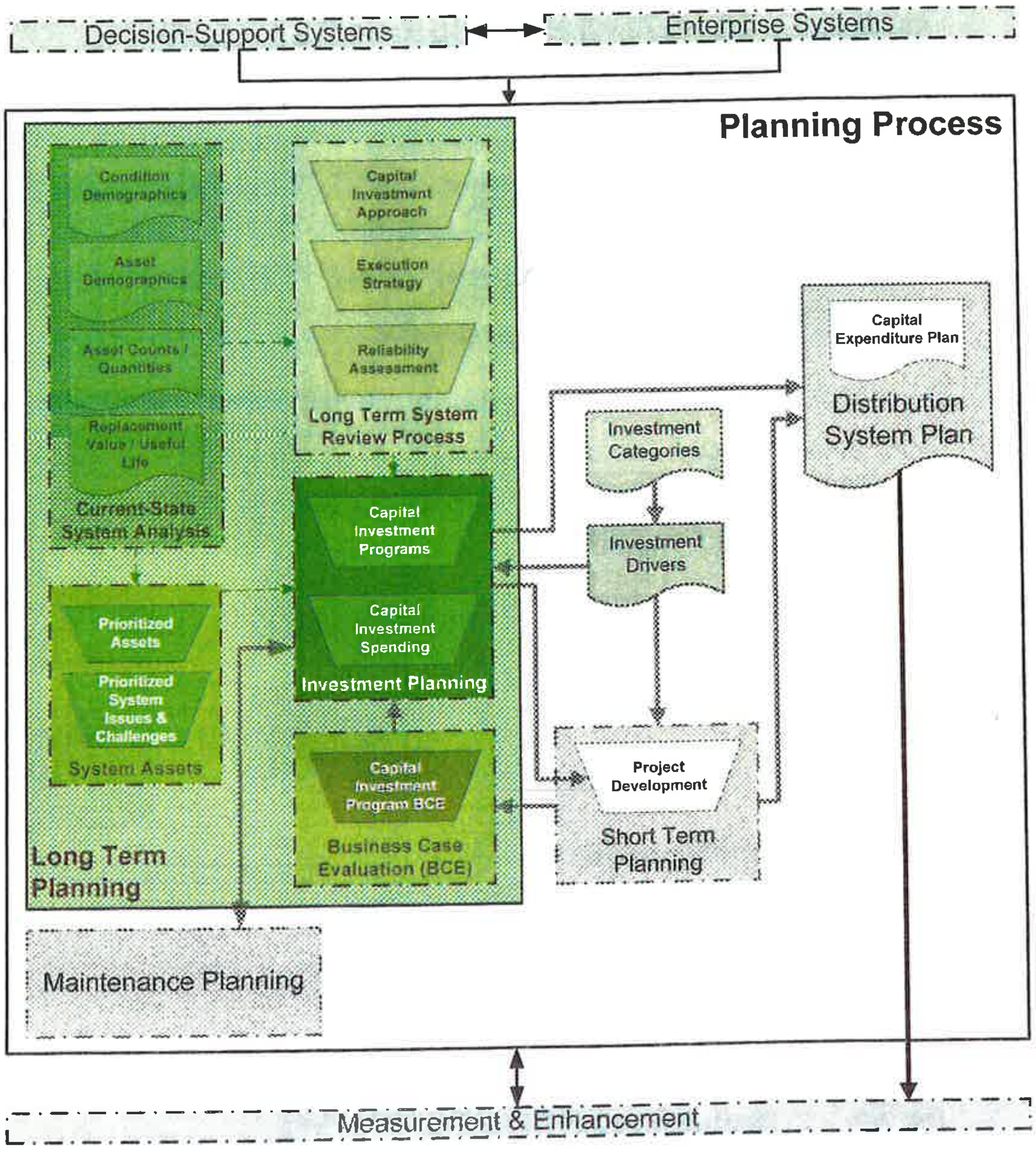


FIGURE 3: LONG-TERM PLANNING PROCESS

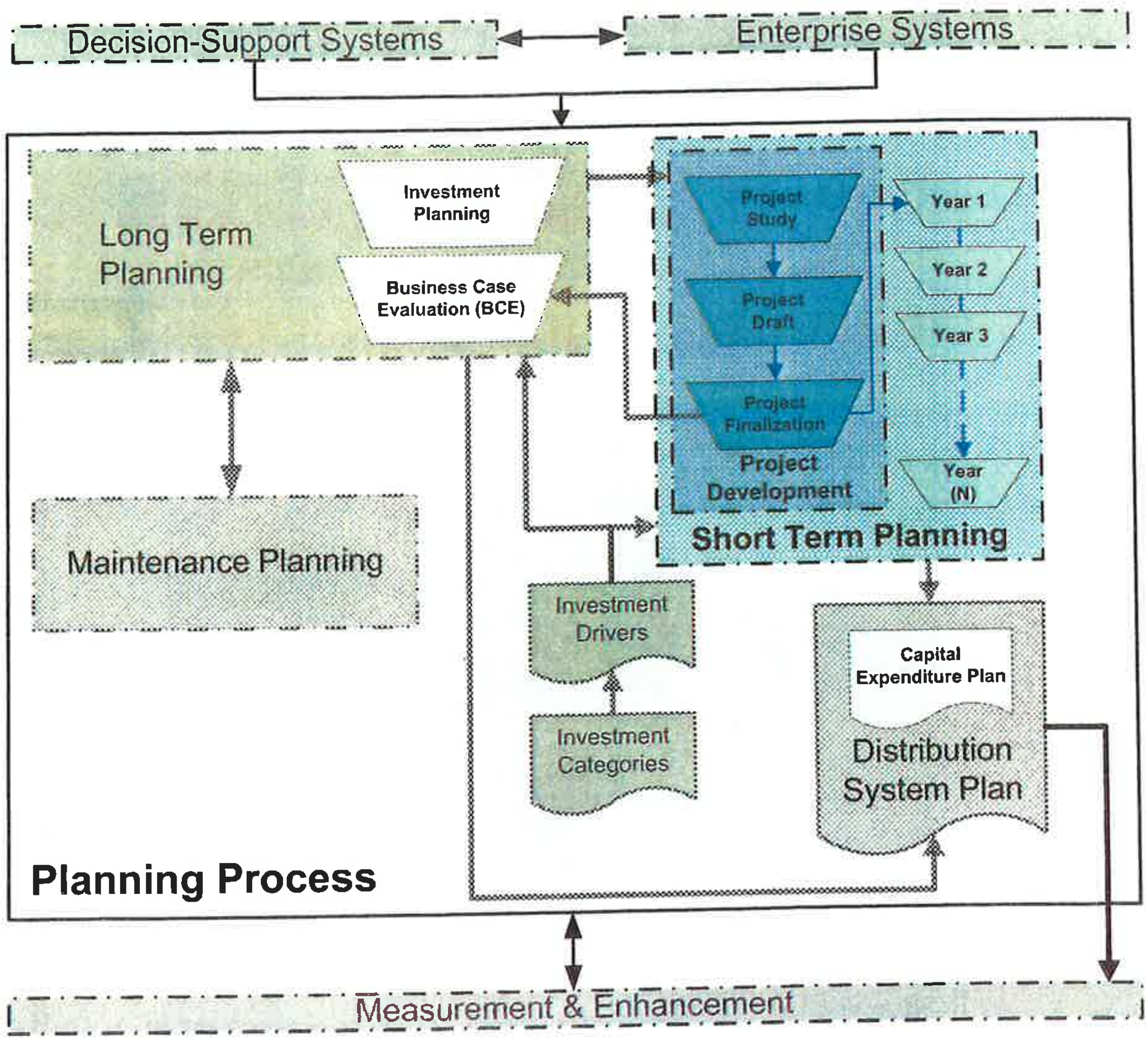
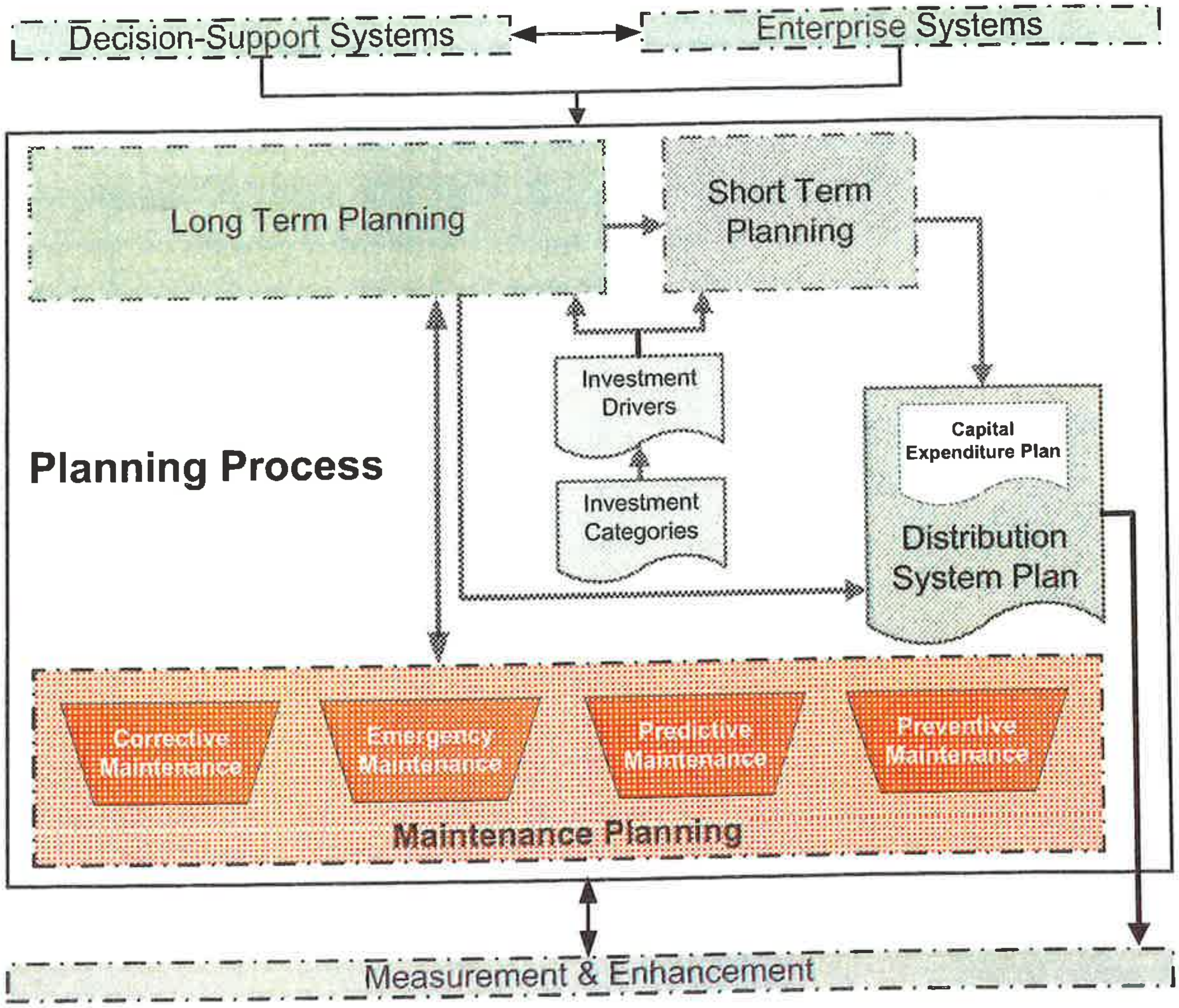


FIGURE 4: SHORT-TERM PLANNING PROCESS

D1.2.3 Maintenance Planning Process

Toronto Hydro's maintenance planning process is designed to assess the condition and extend the life of distribution assets, and maintain their reliability through the development of maintenance programs. Maintenance programs are designed to extract the maximum value from the assets. Maintenance programs complement the produced capital investment programs by allowing Toronto Hydro to sustain the intended operating condition of its asset and preserve operability. Equipment condition is also critical to the safe operation of distribution assets and



1 **FIGURE 5: MAINTENANCE PLANNING PROCESS**

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

UNDERTAKING NO. J1.7 and Response to Member Quesnelle''s Question Posed during the Evidence Presentation":

Reference(s):

To calculate the financial life of a portion of the assets and economic life of a portion of the assets, on a best efforts basis and provide it if it is relevant; otherwise advise if it is not relevant.

RESPONSE:

In the course of the Evidence Conference, Member Quesnelle asked Toronto Hydro to comment on the relationship between the financial treatment of assets (i.e., Financial Useful Life) and the optimal replacement strategy embodied in the steady state concept (i.e., Economic End-of-Life). What follows in this response demonstrates that the financial assumptions that are made for financial reporting purposes have a dynamic relationship to good engineering, system care and economic decision-making.

The distribution system is in steady state when the backlog of assets operating beyond end-of-life and hence the aggregate operating (or lifecycle) cost is effectively minimized. Toronto Hydro uses a variety of measures to inform its judgment regarding the optimal replacement strategy, which balances system needs with value for ratepayers. (These concepts are explained in Exhibit 2B, Section D.)

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

As indicated in the evidence, the most compelling approach from an economic perspective is to immediately replace the backlog of assets operating beyond end-of-life so that the cost of ownership would be balanced sooner. However, Toronto Hydro has adopted a paced approach for the CIR application. The utility's capital needs currently exceed depreciation. Capital expenditures are expected to converge towards deprecation over time if the investments reflected in the application are made as and when required.

While capital costs and depreciation are expected to converge, this not the same as saying that the Financial Useful Life of assets (i.e., depreciation periods) will converge with their Economic End-of-Life values (i.e., optimal replacement time). These two measures are fundamentally different. The financial lives are based on the range of expected service lives of asset classes as derived from the 2009 "Useful Life of Assets" study.[1] In contrast, the economic lives are determined on an individual basis for each asset based on its particular age and condition (if information is available) and its risk cost.[2]

For these reasons, Economic End-of-Life could not be used to calculate the Financial Useful Life and associated depreciation expense under MIFRS. The economic lives of individual assets within an asset class can vary substantially (for an example see Undertaking J1.15) and can change based on changes in system configuration. Thus economic lives do not offer a consistent and stable metric for recovery of capital cost."

The intent of this undertaking and the other two undertakings that were provided with respect to the concept of "useful life" (namely J1.14 and J1.16) is to facilitate a

[1] Prepared by Kinectrics for Toronto Hydro and filed in EB-2010-0142 (Exhibit Q1, Tab 2)
[2] Risk cost is largely a product of the excess cost to replace an asset on an emergency basis and the interruption cost experienced by customers if it fails, which in turn is based on each individual asset's particular configuration within the distribution system.

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

comparison of three useful life metrics that Toronto Hydro utilizes – Financial Useful Life, Useful Life, and Economic End-of-Life – and to explain the relationship between the metrics and how they relate to Toronto Hydro's capital needs.

In the response that follows, Toronto Hydro provides: (1) definitions of the three metrics; (2) an explanation of how these metrics are derived and applied in Toronto Hydro's financial and investment planning policies and processes; and (3) a table, filed as Appendix A, comparing the asset age values for each of the three concepts for various asset classes.

Metrics Definitions

The three metrics in question are defined as follows:

- Financial Useful Life (also previously referred to as "depreciation life") is the period over which an asset is depreciated, resulting in depreciation expense.
- Useful Life (also referred to as "end-of-life" or previously referred to as "engineering end-of-life") is the mean service life of the asset. This metric is used as part of the Current-State System Analysis to determine the percentage of assets at, approaching or beyond their useful lives, and is also used as one of several inputs in the failure probability calculation for assets within the Feeder Investment Model (FIM).
- Economic End-of-Life (also known as "Optimal Intervention Time") is used to determine the intervention time of an existing asset, based upon the optimal relationship between the minimum life cycle cost of the new asset to be installed and the existing asset's risk cost. See Exhibit 2B, Section D3, Figure 3, page 8, which is reproduced on page 6 of this response.

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

Generally, Toronto Hydro uses these metrics and models as tools and indicators to inform decision-making processes. Planning engineers consider the Useful Life and Economic End-of-Life metrics and use their outputs to inform their exercise of professional judgment in the management of asset risk and system reliability. Financial Useful Life is used to account for Toronto Hydro's rate base. Ultimately, decisions whether to replace assets sooner or later than on the basis of one or more of these indicators are based on a number of considerations that must be taken into account in prudent utility management and investment. These include operating characteristics, execution considerations, customer needs, and service obligations.

The following subsections further explain how these metrics are applied in Toronto Hydro's financial and investment planning policies and processes.

Financial Useful Life

Based upon the conclusions of the independent detailed review of useful lives conducted by Kinectrics (please refer to the 2009 Kinectrics "Useful Life of Assets" report filed in EB-2010-0142 at Exhibit Q1, Tab 2), Toronto Hydro implemented certain changes in accounting estimates related to the manner in which it records and accounts for its property, plant and equipment in accordance with the OEB's reporting standards. The changes in estimates of Financial Useful Lives of assets were reflected in the corresponding depreciation and amortization balances in Toronto Hydro's financial statements effective January 1, 2011, and in Toronto Hydro's last rebasing application (EB-2010-0142). The Financial Useful Lives were within the ranges provided by Kinectrics.

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

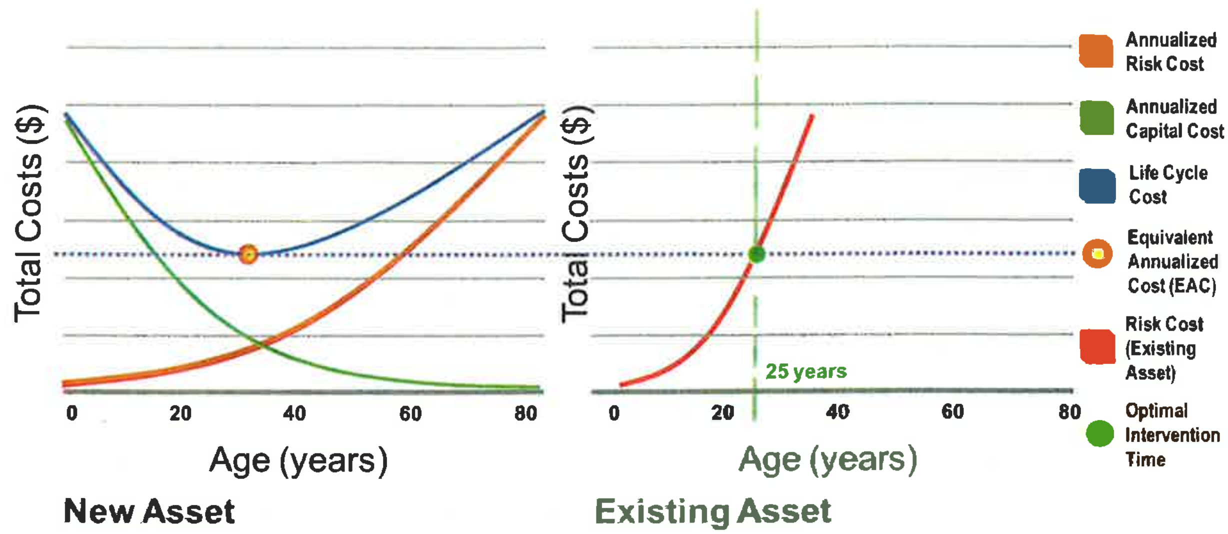
Useful Life

Useful Life values are also derived from the 2009 Kinectrics "Useful Life of Assets" report. As previously explained in the interrogatory response to OEB Board Staff 36 (b), the Useful Life is calculated by identifying the mid-point between the "minimum useful life" and the "maximum useful life" values as defined within the Kinectrics report. Many of the hazard rate distribution functions used to determine the age-based failure probability within the FIM for a given asset have been calibrated using these Useful Life values. These values are also used as part of the Current-State System Analysis (explained in Section D3.1.1.1 of Toronto Hydro's Distribution System Plan) in order to determine the replacement value of assets prior to, approaching or exceeding their useful lives.

Economic End-of-Life

The figure below provides a graphical representation of Economic End-of-Life. On the left side of the figure, the life cycle cost of a new asset (illustrated by the blue curve) is calculated by performing the simple sum of the annualized capital cost (illustrated by the green curve) and the annualized risk cost (illustrated by the orange curve).

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



The annualized capital cost is derived from the cost of replacing the existing asset with the new asset – this cost has been annualized as a yearly cost across the life-cycle of the new asset. The minimum life-cycle cost – also referred to as the Equivalent Annualized Cost (EAC) – will be cross-referenced against the existing asset's risk cost curve – illustrated by the red curve on the right side of the figure – in order to determine the optimal intervention time, also known as the Economic End-of-Life of the existing asset. At this point, it becomes more cost-efficient to replace the existing asset than to continue operating it.

Comparison of Metrics Values

To compare the three metrics, Toronto Hydro has included a table in Appendix A that shows the Financial Useful Life for each of Toronto Hydro's distribution asset classes, along with the Useful Life and Economic End-of-Life for each of these classes where applicable and available. The Economic End-of-Life results are presented as a range of

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

values because these values vary from asset to asset. In contrast, Financial Useful Life and Useful Life values are in each case the same for all assets within a given asset class.

Please note that the Useful Life and Economic End-of-Life results in Appendix A have not been provided for all Financial Useful Life asset classes. Useful Life is given only for the subset of asset classes where this metric is applied within the AM Planning Process. Ranges of Economic End-of-Life values are currently unavailable for certain asset classes because they have not been modeled or there is insufficient data for the purposes of this exercise.

Conclusion

Toronto Hydro's capital needs for the five-year CIR period are demonstrated by the number of assets operating beyond Useful Life and the rate at which existing assets continue to reach the end of Useful Life (i.e., the 26% and 7% figures shown on Slide 8 of Exhibit EC1). The backlog of assets requiring renewal in the 2015-2019 period are already operating well beyond their Economic End-of-Life. As a consequence, within this period, the FIM is a tool to establish the relative priority of program expenditures. As detailed in slide 24 of the Evidence Conference (Exhibit EC1), Toronto Hydro uses a number of decision-support systems to plan investments. The capital plan that Toronto Hydro has proposed is a consequence of engineering judgment based on rigorous asset management processes and tools, assumptions and data points, all of which are informed by, but not solely based on, the metrics and indicators of useful life discussed in this response.

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	Asset	USoA Account Number	USoA Account Description	Depreciation Useful Life	Useful Life		Economic End of Life 1		
							Min	Mid	Max
	Poles	1830	Poles, Towers and Fixtures	40 - 50	Poles - Wood, Concrete, Steel	45	3	61	100*
	OH Switch	1835	Overhead Conductors and Devices	30	OH Switch - Load Break	40	2	27	100*
					OH Switch - Disconnect	45	1	32	83
					OH Switch - SCADAMATE	40	2	11	100*
	O/H SMD - 20 Switches	1835	Overhead Conductors and Devices	45	NA		NA	NA	NA
	OH Primary Conductors	1835	Overhead Conductors and Devices	50	OH Primary Conductor	64	NA	NA	NA
	OH Secondary Conductors	1855	Services	50	OH Secondary Conductor	64	NA	NA	NA
	OH Transformers	1850	Line Transformers	30	OH TX	35	1	39	114*
Stations	Power Transformers	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	Stations - Power TX	44	NA	NA	NA
		1820	Distribution Station Equipment - Normally Primary Below 50 kV	32			NA	NA	NA
	AC Station Service Equip (TS)	1815	Transformer Station Equipment - Normally Primary Above 50 kV	32	NA		NA	NA	NA
	AC Station Service Equip (MS)	1820	Distribution Station Equipment - Normally Primary Below 50 kV	32	NA		NA	NA	NA
	Stations Grounding Transformer	1820	Distribution Station Equipment - Normally Primary Below 50 kV	25 - 30	NA		NA	NA	NA
	Stations - DC Batteries	1820	Distribution Station Equipment - Normally Primary Below 50 kV	10	Stations - DC Batteries	10	NA	NA	NA
	Storage Battery Equipment	1825	Storage Battery Equipment	15	NA		NA	NA	NA
	DC Station Service Battery Charger	1820	Distribution Station Equipment - Normally Primary Below 50 kV	20	NA		NA	NA	NA
	Stations Switchgear	1820	Distribution Station Equipment - Normally Primary Below 50 kV	40	Stations - Switchgear Enclosures	50	NA	NA	NA
	Substation Equipment - Outdoor Breaker	1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	CB - Air Blast	40	NA	NA	NA
					CB - Magnetic Air	43	NA	NA	NA
					CB - SF6	45	NA	NA	NA
					CB - Vacuum	45	NA	NA	NA
					CB - Oil	45	NA	NA	NA
	Transformer Station Equip - Disconnect Switch	1815	Transformer Station Equipment - Normally Primary Above 50 kV	30	NA		NA	NA	NA
	Substation Equipment - Disconnect Switch	1820	Distribution Station Equipment - Normally Primary Below 50 kV	30	NA		NA	NA	NA
	Digital & Numeric Relays	1980	System Supervisory Equipment	20	NA		NA	NA	NA
	Transformer Station Equip - Steel Structure & OH Bus	1815	Transformer Station Equipment - Normally Primary Above 50 kV	35	NA		NA	NA	NA
	Transformer Station Equip - Steel Structure & OH Bus	1820	Distribution Station Equipment - Normally Primary Below 50 kV	35	NA		NA	NA	NA
	UG Primary Cable - PILC	1845	Underground Conductors and Devices	60	UG Primary Cable - PILC	75	31	100	100*
	UG Primary (Direct Buried)	1845	Underground Conductors and Devices	20	UG Primary Cable - DB Jacketed	40	23	49	100
					UG Primary Cable - DB Unjacketed	23	8	36	66
					UG Primary Cable - Conduit, Jacketed	50	21	62	100*

	Asset	USoA Account Number	USoA Account Description	Depreciation Useful Life	Useful Life		Economic End of Life 1 Min	Mid	Max
UG	U/G Dist Lines And Feeders - Primary Cable in Duct	1845	Underground Conductors and Devices	40	UG Primary Cable - Conduit, Unjacketed	50	17	52	100*
					UG Primary Cable - Concrete, Unjacketed	50	20	63	100*
					UG Primary Cable - Concrete, Jacketed	50	21	62	100*
	UG Secondary Cable Direct Buried	1845	Underground Conductors and Devices	20	UG Secondary Cable - DB	23	NA	NA	NA
	UG Secondary Services - Direct Buried	1855	Services	20			NA	NA	NA
	UG Secondary Cable - In Duct	1845	Underground Conductors and Devices	40	UG Secondary Cable - Conduit	50	NA	NA	NA
	UG Secondary Services - In Duct	1855	Services	40			NA	NA	NA
	UG Network Transformers	1850	Line Transformers	20	UG Network Units - Fibertop	30	12	47	67
					UG Network Units - Semi-Dust-Type	30	3	44	100*
					UG Network Units - Submersible	30	2	100	100*
	UG Transformers	1850	Line Transformers	30	UG TX - Pad-Mounted	35	3	21	90
					UG TX - Submersible	33	3	21	100*
	Vaults	1840	Underground Conduit	40	Civil - Network Vaults	60	5	70	100*
					Civil - UG Submersible Tx Vault	60	NA	NA	NA
	Vault Roofs	1840	Underground Conduit	20	Civil - Network Vaults Roofs	25	NA	NA	NA
	Vault Switches	1845	Underground Conductors and Devices	30	UG Switch - Minirupter	40	3	32	100*
	UG Switches - Padmount Switchgear	1845	Underground Conductors and Devices	20	UG Switch - PMH	30	7	100	100*
					UG Switch - SF6	40	8	26	100*
					UG Switch - SF6 PAD SCADA	35	10	100	100*
	Civil - Duct Structures	1840	Underground Conduit	30	NA		NA	NA	NA
	Cable Chambers	1840	Underground Conduit	50	Civil - Cable Chambers	65	NA	NA	NA
	Cable Chambers - Roof	1840	Underground Conduit	20	Civil - Cable Chambers Roof	25	NA	NA	NA
	System Supervisory Equipment	1835	System Supervisory Equipment	30	NA		NA	NA	NA
		1980	System Supervisory Equipment	15 - 30	NA		NA	NA	NA
Meters	Residential Energy Meters	1860	Meters	25	Residential Energy Meters	18	NA	NA	NA
	Industrial/Commercial Energy Meters	1860	Meters	25	Industrial/Commercial Energy Meters	18	NA	NA	NA
	Wholesale Energy Meters	1860	Meters	25	Wholesale Energy Meters	18	NA	NA	NA
	Current & Potential Transformer (CT & PT)	1860	Meters	25 - 40	Current & Potential Transformer (CT & PT)	18	NA	NA	NA
	Smart Meters	1860	Meters	15	Smart Meters	18	NA	NA	NA
		1970	Load Management Controls - Customer Premises	10		18	NA	NA	NA

ote 1: In some cases, the Economic End-of-Life results at the minimum range will indicate assets at a very young age that require replacement – this may be due to the manner in which these assets are connected, as a significant amount of customers ay experience an outage should those assets fail. In these instances, the FIM could be indicating that it is worthwhile to reconfigure the existing state of assets such that a reduced amount of customers are exposed to an impact of failure. On the aximum end of the range, there are certain assets that have received Economic End-of-Life results of 100 or 114 years of age (marked with asterisks in this table) – in actuality, these Economic End-of-Life results represent the limits of the time domain hat is being evaluated within the FIM, and the actual Economic End-of-Life results in these instances may be a higher age beyond these time intervals.

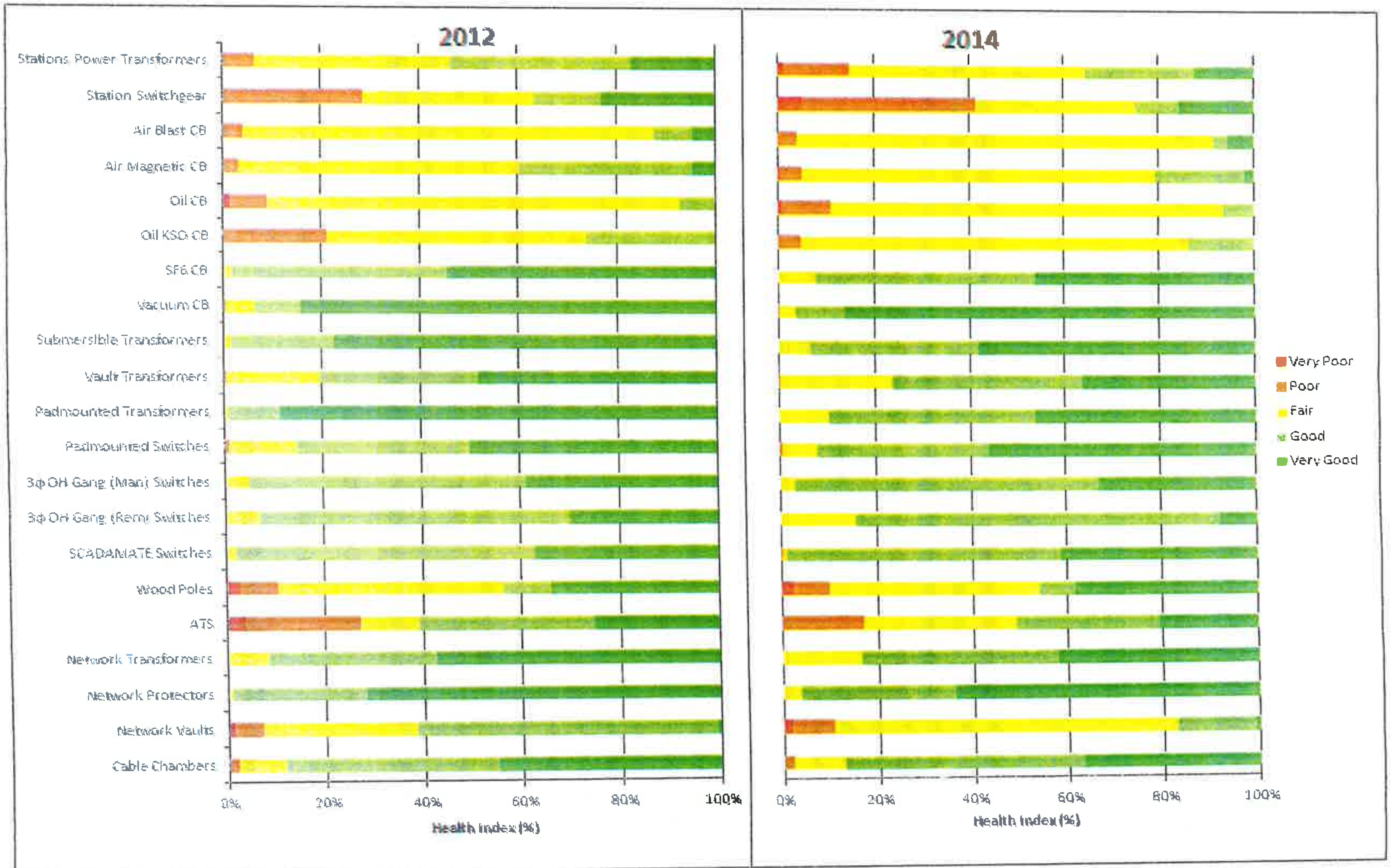

Figure 3 Graphical Summary of Health Index Distribution

The general trend for asset classes listed above is that the number of units in "Good" and "Very Good" condition is decreasing, while the number of units in "Fair", "Poor" and "Very Poor" condition is increasing. This is representative of THESL's ageing infrastructure.

Figure 3: Health Index Distribution Change

Assets within the Health Index Calculator can be grouped into four main categories, stations assets, network distribution, overhead and underground. Though some asset classes can be found in more than one grouping, for instance cable chambers are found in

AMPCO Table

Exhibit 2B Secrion D2 Appendix A: 2014 Audit Results By Asset Class

Asset	Population	Sample Size %	% very poor	% poor	% fair	% good	% very good	% very poor & poor	% very poor, poor & fair	# very poor	# poor	# fair	# good	# very good	Total	% very poor & poor	% very poor, poor & fair
1 Station Power Transformer	268	90.30	1.24%	13.64%	49.59%	23.14%	12.40%	14.88%	64.47%	3	37	133	62	33	268	40	173
2 Station Switchgear	279	88.89	4.84%	36.69%	33.47%	9.27%	15.73%	41.53%	75.00%	14	102	93	26	44	279	116	209
3 *Air Blast Circuit Breakers*	290	62.07	0.00%	3.89%	87.78%	2.78%	5.56%	3.89%	91.67%	0	11	255	8	16	290	11	266
4 *Air Magnetic Circuit Breakers*	627	74.32	0.21%	4.72%	74.25%	18.88%	1.93%	4.93%	79.18%	1	30	466	118	12	627	31	496
5 Oil Circuit Breakers	332	47.29	0.64%	10.19%	82.80%	6.37%	0.00%	10.83%	93.63%	2	34	275	21	0	332	36	311
6 *Oil KSO Breakers*	59	37.29	0.00%	4.55%	81.82%	13.64%	0.00%	4.55%	86.37%	0	3	48	8	0	59	3	51
7 SF6 Circuit Breaker	201	32.34	0.00%	0.00%	7.69%	46.15%	46.15%	0.00%	7.69%	0	0	15	93	93	201	0	15
8 Vacuum Circuit Breakers	675	70.81	0.00%	0.21%	3.14%	10.25%	86.40%	0.21%	3.35%	0	1	21	69	583	675	1	23
9 Submersible Transformers	9554	95.20	0.00%	0.02%	6.68%	34.93%	58.36%	0.02%	6.70%	0	2	638	3337	5576	9553	2	640
10 Vault Transformers	13034	88.24	0.00%	0.23%	23.48%	39.80%	36.50%	0.23%	23.71%	0	30	3060	5188	4757	13035	30	3090
11 Padmounted Transformers	7160	84.55	0.00%	0.02%	10.09%	43.51%	46.38%	0.02%	10.11%	0	1	722	3115	3321	7160	1	724
12 Padmounted Switches	802	97.01	0.00%	0.39%	7.20%	36.12%	56.30%	0.39%	7.59%	0	3	58	290	452	802	3	61
13 3 Phase O/H Gang Manual Switches	1108	32.94	0.00%	0.39%	3.01%	63.84%	33.15%	0.39%	3.40%	0	4	33	707	367	1112	4	38
14 3 Phase O/H Gang Remote Switches	15	86.67	0.00%	0.00%	15.38%	76.92%	7.69%	0.00%	15.38%	0	0	2	12	1	15	0	2
15 SCADAMATE Switches	926	85.31	0.13%	0.00%	1.14%	57.34%	41.39%	0.13%	1.27%	1	0	11	531	383	926	1	12
16 Wood Poles	123280	37.66	2.34%	7.64%	44.13%	7.28%	38.61%	9.98%	54.11%	2885	9419	54403	8975	47598	123280	12303	66707
17 Automatic Transfer Switches	58	91.38	0.00%	16.98%	32.08%	30.19%	20.75%	16.98%	49.06%	0	10	19	18	12	58	10	28
18 Network Transformers	1892	99.58	0.00%	0.00%	16.40%	41.45%	42.14%	0.00%	16.40%	0	0	310	784	797	1892	0	310
19 Network Protectors	1615	97.52	0.00%	0.00%	3.75%	32.25%	64.00%	0.00%	3.75%	0	0	61	521	1034	1615	0	61
20 Network Vaults	1062	99.53	1.70%	8.80%	72.37%	16.08%	1.04%	10.50%	82.87%	18	93	769	171	11	1062	112	880
21 Cable Cambers	10902	35.01	0.26%	1.60%	10.77%	50.17%	37.20%	1.86%	12.63%	28	174	1174	5470	4056	10902	203	1377

A3.2.2 Future Enhancements

Toronto Hydro is also examining and exploring future enhancements to further improve upon its AM planning process. These include:

- Potential enhancements to the Feeder Investment Model (FIM) in order to respond to feedback provided as part of the 2012-2014 IRM Filing submission. These include:
    - Geospatial tracking of non-asset-related outage events to further improve the calculation of non-asset-related risks
    - Improvements to link customer data to assets in order to improve asset-level load impact data used as part of the outage cost calculation procedure
    - Improvements to customer interruption costs used as part of the outage cost calculation procedure. These have been further defined as part of the Program Support capital investment program in Section E8.8.
- Introduction of performance measures as described in Section C to measure progress and effectiveness of Toronto Hydro's Distribution System Plan. These measures will be used to further enhance Toronto Hydro's AM process.

Power System Engineering, Inc.

Full-service consultants

Standards Review Study

Prepared for:

Toronto-Hydro Electric System Limited

TORONTO HYDRO

January 16, 2014

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4 Distribution Construction Standards

The Distribution Construction Standards (DCS) provide Standards applicable to construction of the THESL electric distribution system.

Similar to the SDP, the DCS were found by PSE and LHB to be thorough, well documented, and consistent with what is seen in the industry throughout North America. Only minor comments and questions resulted from the review.

In general, the DCS follow industry-wide practices that are standard for overhead framing. Standard installation configurations are also used for underground construction. The DCS reference standard materials that are commonly used throughout the industry for both overhead and underground construction.

The DCS were found to be acceptable as shown, subject to several minor suggested modifications that have been discussed with the THESL staff. Overall, the construction assembly configurations would not be perceived as difficult for an installing contractor to understand. The Standards appear to address design and planning considerations, constructability issues, and flexibility to accommodate field conditions. They also provide appropriate consideration to environmental safety (ex. the use of Petro-Plug devices on chamber drains, and the beneficial reuse of concrete transformer pads).

Very few and minor deviations from what may be considered industry-wide standards were noted during the review and evaluation. Of those noted, the deviations were either reasonably justified by THESL due to local conditions and codes, or were undertaken for review and modification by THESL. For example, split bolt connectors were listed in some of the Standards. It was suggested that minimal use of split bolt connectors be considered for overhead tap connection. Because of the design, split bolt connectors are more likely to fail under high electric current loads. THESL indicated that Ampact connectors are normally used and that the split bolt connectors are only used when the situation is such that the Ampact, or perhaps a squeeze-on connector, cannot be utilized.

Although it is generally minor, the most noteworthy deviation from the industry found throughout the DCS is THESL's exclusive use of Western Cedar poles. Through our experience, Western Cedar poles are generally superior to most other wood pole species; however, it is not uncommon for distribution systems to consist of other wood species of lower cost. During the course of the review, THESL explained that they prefer cedar wood for poles because cedar is generally more uniform in dimension, easier to climb, and lightweight. These beneficial factors, as well as the life longevity of Western Cedar, may very well offset the typically higher cost. Through discussion, THESL agreed that it would be appropriate to perform a comparison review of other wood species such as Northern Red and Southern Yellow Pine to determine if Western Cedar continues to be the best option in terms of cost, safety, and reliability.

Overall, the approximately 1000 standards reviewed that make up the DCS were found to be neither excessive nor delinquent in terms of construction for a distribution system with a focus on reliability, safety, and cost efficiency.

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

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*"]

Distribution System Plan (DSP)

C PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

ID	Section
C1	Overview of Continuous Improvement Principles and Approach
C2	Customer Oriented Performance
C3	Cost Efficiency and Effectiveness
C4	Asset and System Operations Performance

C1 OVERVIEW OF CONTINUOUS IMPROVEMENT PRINCIPLES AND APPROACH

C1.1 Introduction

The purpose of this exhibit is to describe Toronto Hydro's proposed Distribution System Plan (DSP) measures that the utility plans to track and periodically report on over the 2015-2019 ratemaking period.

Toronto Hydro has developed a set of 12 measures to monitor quality and drive continuous improvement in its distribution system planning and implementation work over the 2015-2019 planning horizon. The measures cover several distinct dimensions of the utility's capital planning and implementation processes and/or speak directly to the outcomes of such processes, motivated by customer needs, regulatory compliance obligations, or corporate efficiency objectives.

Table 1 outlines Toronto Hydro's proposed DSP performance measures, grouped by primary category.

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.

C2 CUSTOMER ORIENTED PERFORMANCE

C2.1 Reliability Measures – SAIDI, SAIFI, CAIDI

C2.1.1 Measure Description

Toronto Hydro tracks its results on the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) in accordance with the OEB-mandated measurement and reporting practices specified in Section 2.1.4.2 of the *Reporting and Record Keeping Requirements* (RRR) as established by the OEB. The methodology used to calculate and report on these metrics is consistent with the requirements in the OEB's RRR document and IEEE 1366-2012. Calculation of SAIDI, SAIFI, and CAIDI is as follows:

$$\text{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$$

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

$$\text{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$$

Each outage is captured in Toronto Hydro's Interruption Tracking Information System (ITIS), further described in Section D3.1.2.1 (iii) of the DSP. Outage statistics such as Customers Interrupted (CI), Customer Minutes Out (CMO) and Duration are kept as individual entries in each individual report. The ITIS tool was developed in-house to facilitate Toronto Hydro's operational and reporting requirements with respect to outage information tracking and analysis. The CI values, used for SAIFI, and the CMO values, which are an input for SAIDI are tracked in ITIS and aggregated on a monthly basis to derive the Total Number of Customer Interruptions and Minutes Out. To calculate monthly SAIDI and SAIFI values, Toronto Hydro uses the most recent customer count data from its Customer Care and Billing (CC&B) system. At the end of the year, Toronto Hydro aggregates the monthly SAIDI and SAIFI values to calculate the annual reliability measure values. All SAIFI, SAIDI, and CAIDI values showcased further in this document are based on year-end calculations. Toronto Hydro excludes the major event days (MEDs), as defined by IEEE 1366-2012 2.5 beta method, from all representations of reliability metrics.

C2.1.2 Historical Performance Trends

Figures 1, 2, 3, and 4 respectively illustrate Toronto Hydro's SAIDI, SAIFI and CAIDI over the past five years both including and excluding loss of supply. For SAIDI and SAIFI, the trend over the five year historical period can be attributed to the capital investments made over that time. CAIDI, on the other hand, has remained stable over the five-year historical period, as it is proportional to SAIDI and inversely proportional to SAIFI. As such, when it comes to CAIDI, the improvement of SAIDI is negated by a similar improvement to SAIFI. Toronto Hydro notes that improvements made towards SAIDI and SAIFI can lag the investments by a year or more.

Activities such as rear lot conversion and direct-buried cable replacement that reduce the number and duration of outages are among the investments that have contributed to the historical improvements shown.

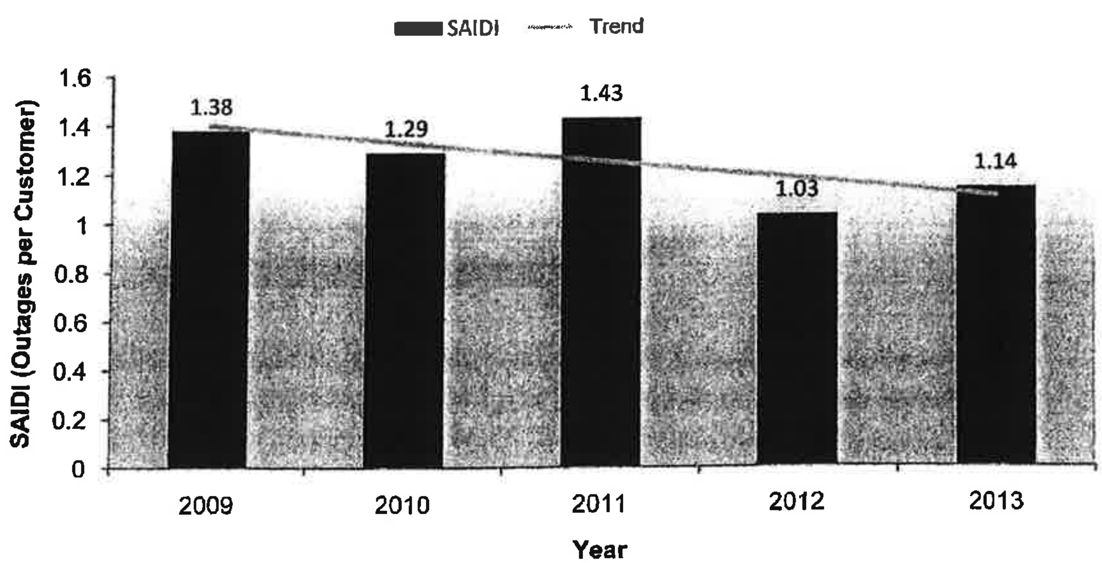


FIGURE 1: HISTORICAL SAIDI EXCLUDING MEDS – 2009-2013

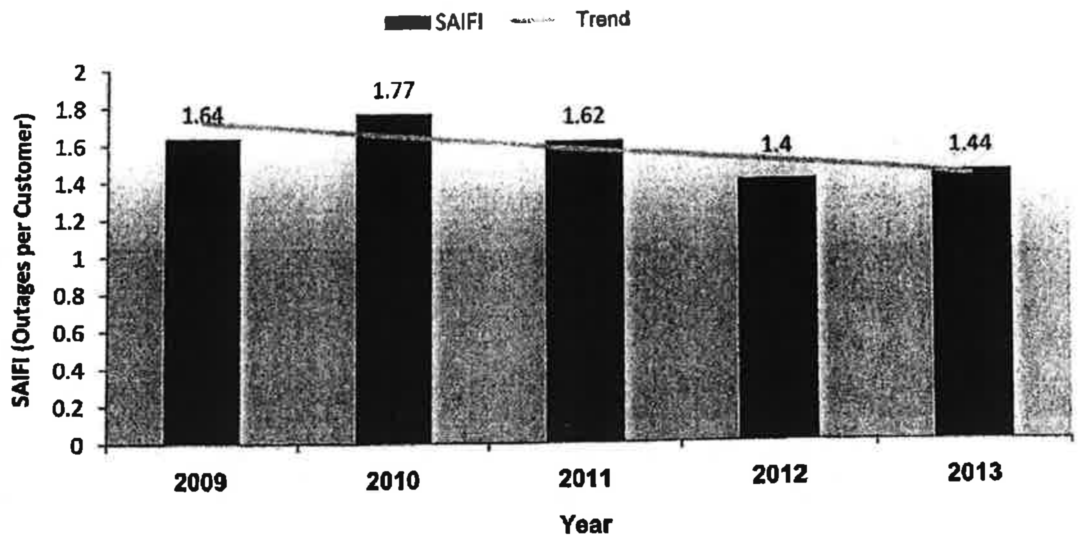


FIGURE 2: HISTORICAL SAIFI EXCLUDING MEDS – 2009-2013

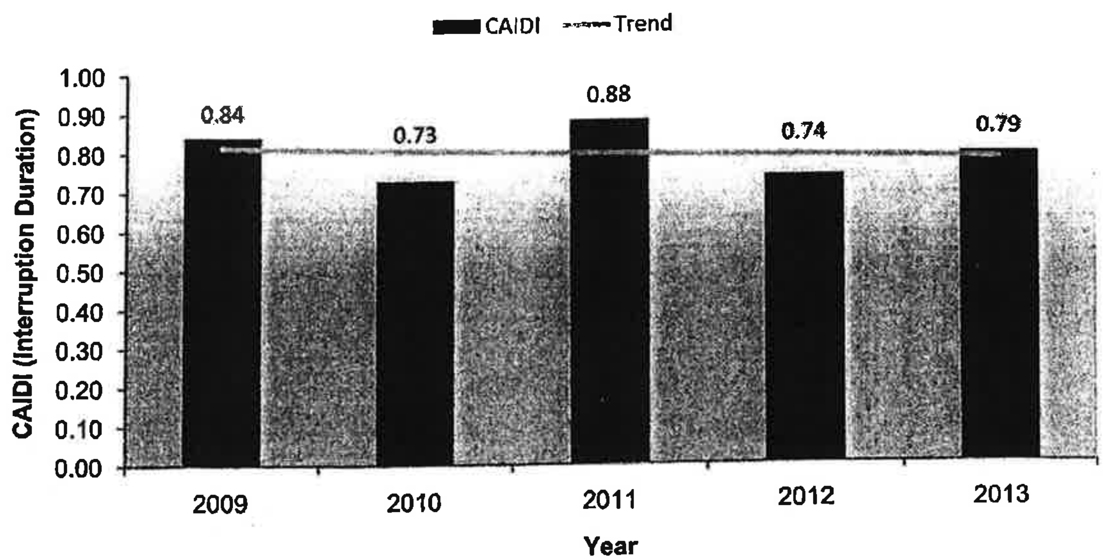
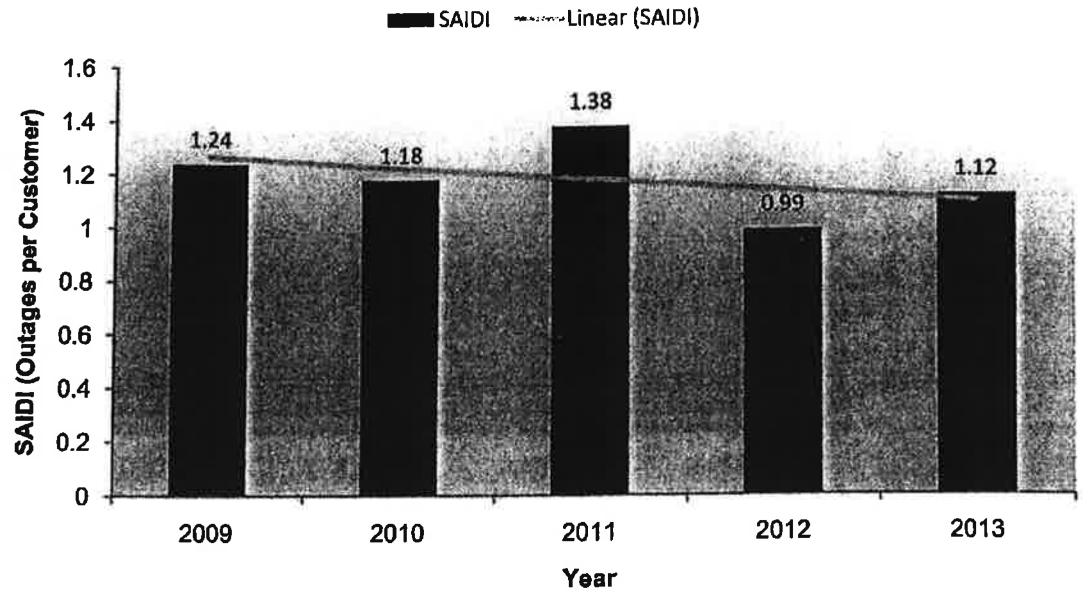
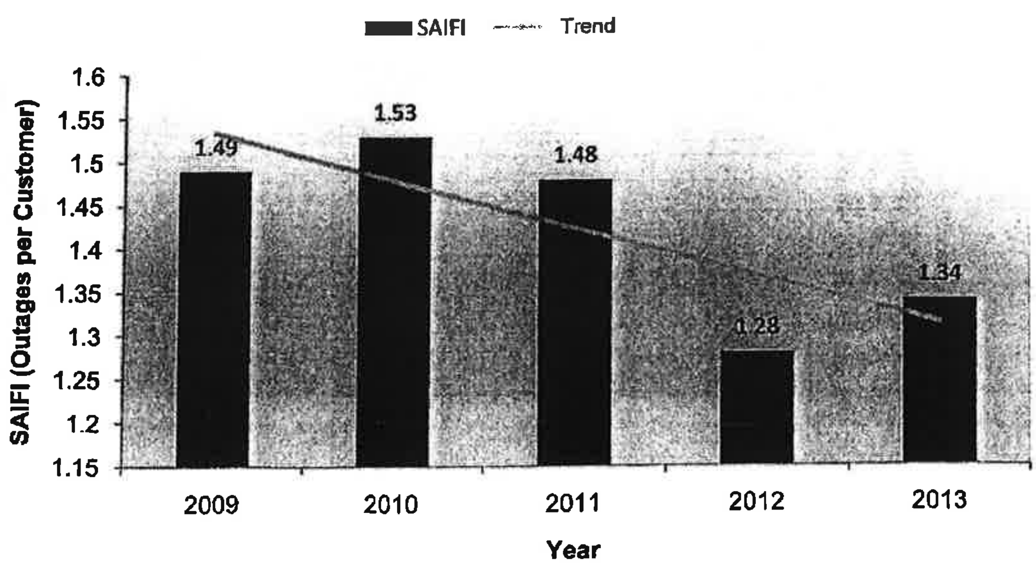


FIGURE 3: HISTORICAL CAIDI EXCLUDING MEDS – 2009-2013



1 **FIGURE 4: HISTORICAL SAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013**



2 **FIGURE 5: HISTORICAL SAIFI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013**

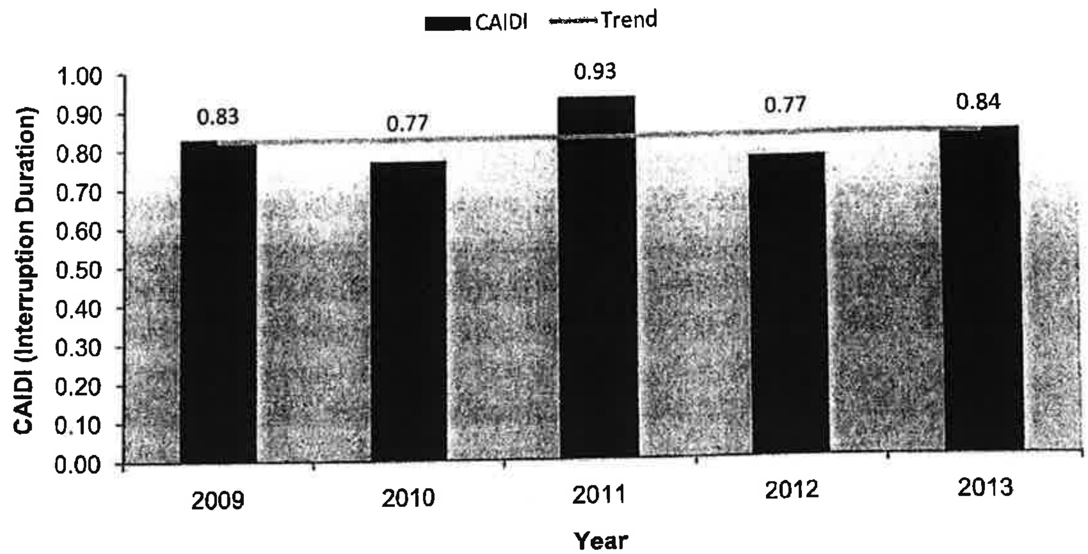


FIGURE 6: HISTORICAL CAIDI EXCLUDING MEDS AND LOSS OF SUPPLY – 2009-2013

C2.1.3 Interaction with the Distribution System Plan

Toronto Hydro uses historical reliability data as a key input into its Asset Management Process, discussed in further detail in Section D of the DSP. Within the long-term asset management policies, described in Section D3.1.1, reliability data serves as a key input to develop investment programs that will target key assets and manage critical issues. As part of short-term asset management policies, further defined in Section D3.1.2, reliability data is used at a local level to identify opportunities for capital projects.

On a system-wide level, the measures inform the asset management process to identify assets and programs required to address the root issues across the system, including activities such as direct-buried cable replacement, air insulated PMH switchgear and others. At the local or project level, historical SAIDI and SAIFI performance and anticipated improvements are considered when selecting individual assets to be replaced, enhanced or modified. On a system level, SAIDI and SAIFI are projected to improve by about 20% and 26% respectively by the end of the CIR period due to the investment programs proposed. Once again, Toronto Hydro expects CAIDI to remain relatively stable as SAIDI and SAIFI are improving in a similar trend.

C2.2 Feeders Experiencing Sustained Interruptions

C2.2.1 Measure Description

The Feeders Experiencing Sustained Interruptions (FESI) measure tracks the number of times Toronto Hydro's feeders (and by extension, some of the customers served by these feeders) are interrupted in a given rolling 12-month period. FESI aims to identify and develop mitigating strategies for the areas with the largest number of annual interruptions. Similar to other reliability metrics, FESI's source of outage data is ITIS. For some tracking measures, such as FESI, the number of feeder interruptions are aggregated by feeder. The measure focuses on interruptions that can be addressed at the feeder level and excludes value such as MEDs, loss of supply, planned interruptions and bus-level interruptions so as to focus on the performance of the feeder itself.

FESI is valuable because it measures pure distribution equipment performance by excluding external non-distribution related events that also impact the feeder level performance. Unlike SAIFI, SAIDI and CAIDI, which are effective for measuring the overall system performance, FESI focuses on specific areas of the distribution system that are underperforming relative to the system averages. Accordingly, the tracking of FESI allows Toronto Hydro to gain insights into the performance of smaller neighbourhoods and individual streets so that the overall customer experience can be improved.

As described in the Worst Performing Feeder Program (E6.21), Toronto Hydro's current management approach related to issues measured by FESI focuses on feeders that have experienced seven or more interruptions in a given 12-month period. Toronto Hydro established the threshold of seven outages based on a review of its historical feeder-level performance statistics, which determined that 3.5% of all feeders (those with seven or more annual outages) in the system were responsible for about half of the total system SAIDI and SAIFI. For the purposes of annual tracking, Toronto Hydro proposes to normalize the annual results by excluding Major Event Days and Loss of Supply events.

C2.2.2 Historical Performance Trends

Figure 7 shows Toronto Hydro's historical FESI-7 performance over the last five years, along with the associated trend. The number of feeders sustaining seven or more interruptions has decreased from 38 in 2009 to 33 in 2013, and declining to as low as 29 in 2012. The average number of feeders with seven or more interruptions in 2009-2013 was 35.

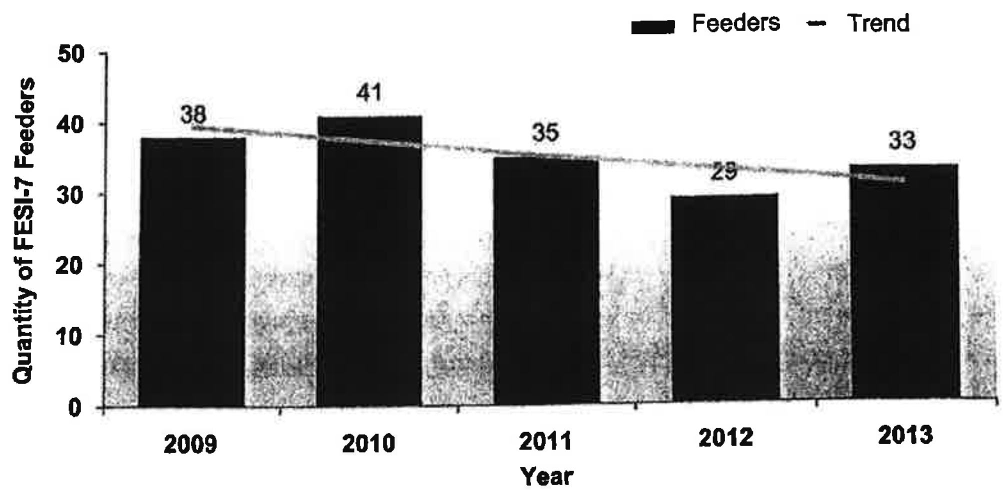


FIGURE 7: QUANTITY OF FESI-7 FEEDERS –2009-2013

C2.2.3 Interaction with the Distribution System Plan

The declining trend illustrated above speaks to the effectiveness of Toronto Hydro's Worst Performing Feeder program over the recent years, including specific reliability-driven capital and maintenance programs, such as tree trimming, targeted asset replacement, insulator washing and animal guard replacement. Toronto Hydro plans to continue monitoring the outcomes of its investments targeted towards service improvements on the utility's worst performing feeders. The Worst Performing Feeder Program (E6.21) contains a detailed list of maintenance and capital work planned to target FESI feeders. However, beyond the specific work planned as part of the Worst Performing Feeder program, which deals with primarily short term mitigation, every aspect of the Toronto Hydro's Capital Expenditure plan that is driven to some degree by reliability (e.g. circuit renewal work), and will ultimately contribute to the improvement of the FESI performance.

Based on the scope and volume of investments proposed within the utility's 2015-2019 Distribution System Plan, Toronto Hydro anticipates that its average number of feeders experiencing seven or more interruptions will continue to decline, or at least remain in line with the 2009-2013 average. At the same time, and as seen from the historical data, some year-over-

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year volatility in single year results can be expected. This volatility stems mainly from large events such as thunder storms or a single failure mode that can cause a single feeder to fail in rapid succession.

C2.3 Momentary Average Interruption Frequency Index

C2.3.1 Measure Description

Momentary Average Interruption Frequency Index (MAIFI) measures the average frequency of momentary interruptions that affect Toronto Hydro's customers. Similar to SAIFI, MAIFI is an aggregation of the number of CI month–over-month, normalized to the number of customers served. Unlike SAIFI, MAIFI tracks only those interruptions lasting less than one minute. MAIFI is calculated as follows:

$$\text{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

Avoidable momentary outages arising from defective equipment or other controllable factors can be a concern for certain customers. Industrial customers can experience interruptions to their normal production schedules, retail customers may experience interruptions to their ability to serve customers, and residential customers can be affected in a number of ways associated with downtime of household appliances or other technology. In extreme cases, a momentary interruption can result in significant damage to customer equipment or machinery.

C2.3.2 Historical Performance Trends

Figure 8 shows Toronto Hydro's historical MAIFI performance over the 2009-2013 period, and the associated trend. As the figure shows, the average frequency of momentary interruptions has decreased from 3.3 per year in 2009 to 2.37 interruptions in 2013 (a 28% improvement), with the five-year average frequency value of 2.74. Toronto Hydro attributes its improved MAIFI performance to the same factors that have led to a decreasing trend in SAIFI. While the two metrics measure different types of events, the activities aimed at reduction of SAIFI can also lead to improvements in MAIFI. Maintenance and capital work such as insulator washing and tree proofing can improve both SAIFI and MAIFI.

Toronto Hydro currently performs MAIFI tracking using a manual data entry process and resource-intensive background analysis, but plans to address this limitation over the 2015-2019 timeframe. In light of these potential process enhancements, Toronto Hydro notes that its MAIFI performance calculated through fully automatic processes may be materially different from the data collected using the manual approach currently employed. At this point, Toronto Hydro is not in a position to assess the direction or magnitude of potential performance changes following automation of the tracking process.

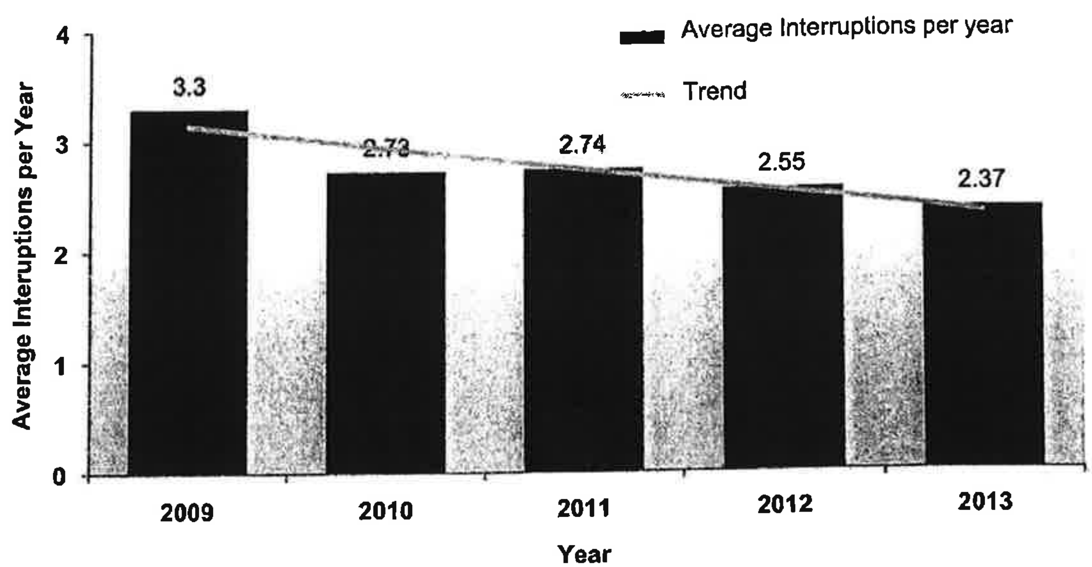
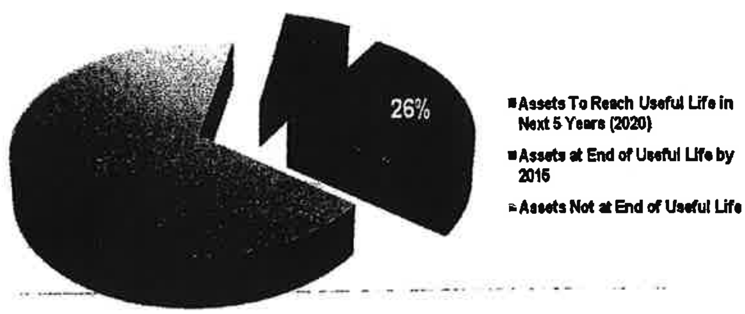


FIGURE 8: MAIFI PERFORMANCE – 2009-2013

C2.3.3 Interaction with the Distribution System Plan

Toronto Hydro's Distribution System Plan and planned maintenance expenditures include a number of programs and projects that are expected to directly and indirectly impact the number of momentary interruptions across the utility's service territory. Programs and activities such as the Overhead Momentary Reduction program, insulator washing, tree trimming and tree proofing are expected to assist in the reduction of avoidable momentary outages. For the purposes of the 2015-2019 planning timeframe, however, Toronto Hydro anticipates its MAIFI levels to improve in line with SAIFI improvements. Both measures reflect the frequency of interruptions, with the key difference that SAIFI measures outages over one minute and MAIFI outages less than one minute. Given the similar measurement criteria, Toronto Hydro expects that its MAIFI results will follow a similar trend to SAIFI projections, subject to the above-rioted measurement considerations. As the utility continues to track its momentary events over the 2015-2019 period, it expects to work with its customers affected by momentary outages and with industry colleagues to devise more precise MAIFI reduction objectives.

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



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

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

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

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

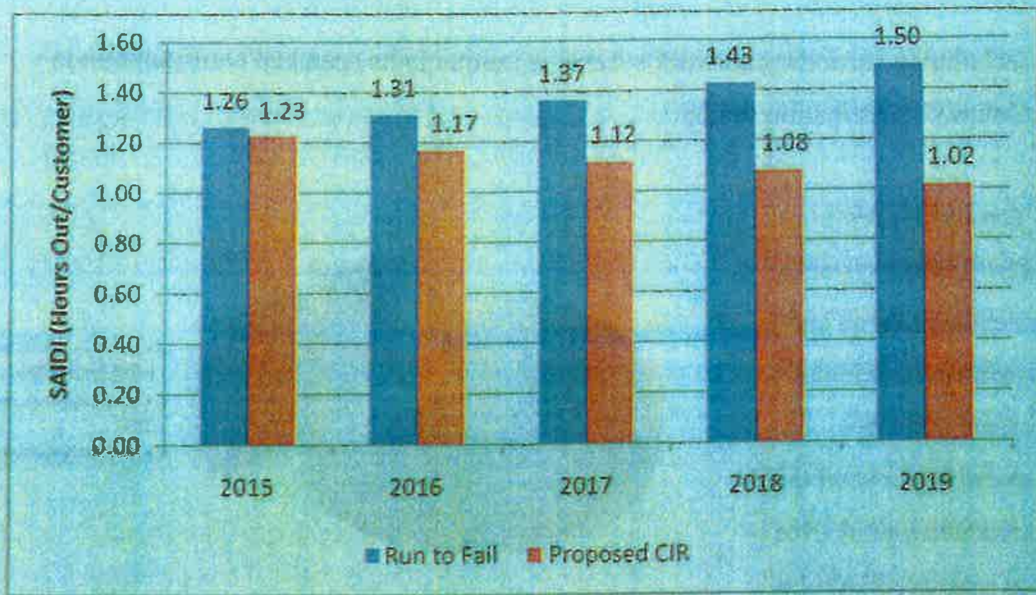


FIGURE 3: FIVE-YEAR SAIDI PROJECTION /C

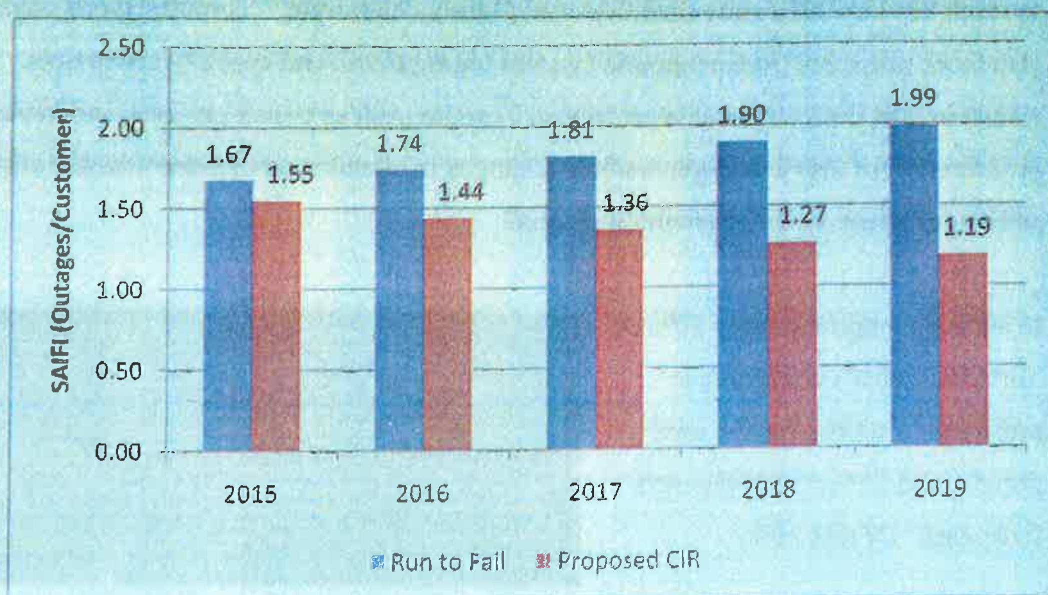


FIGURE 4: FIVE-YEAR SAIFI PROJECTION

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C3 COST EFFICIENCY & EFFECTIVENESS

C3.1 Distribution System Plan Implementation Progress

C3.1.1 Measure Description

Toronto Hydro plans to measure the overall progress of its Distribution System Plan implementation as a rolling ratio of total capital expenditures made over the plan years completed to date, divided by the five-year total amount of OEB-approved capital expenditures approved as a part of the utility's 2015-2019 Distribution System Plan, Including the System Access, System Renewal, System Service, and General Plant investment categories. The proposed measure will be calculated using the following formula:

$$\text{Implementation Progress} = \frac{\sum(\$\,\text{Spend Year n} + \$\text{Spend Year n} + 1\,...)}{\$\,\text{Five Year OEB Approved Plan}}\ [\%\ \text{of Plan Total}]$$

According to this formula, if Toronto Hydro's total five-year approved capital envelope was approved to be $2.47 billion and the utility's Year 1 (2015) and Year 2 (2016) capital expenditures amounted to $524 million, and $502 million respectively, then the utility's plan implementation progress metric at the end of the 2016 rate year would be:

$$\frac{(\$524\text{M} + \$502\text{M})}{\$2.47\text{B}} = 41.5\%$$

Toronto Hydro's preference for using the rolling measure of plan implementation progress stems from the fact that the utility operates in a dynamic business environment, where a number of **issues can emerge over the course of any given year that require the utility to advance,**

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postpone, or otherwise amend the schedule, sequencing or pacing of projects slated for completion in that year. These considerations are often outside of the utility's control, and include the following factors:

- Major weather events (floods, ice storms);
- Atypical seasonal conditions (shorter construction seasons or limited switching capability);
- Urgent third-party work requests (e.g. plant relocations for transit);
- City and/or third-party (e.g. Hydro One Networks Inc. (HONI)) dependencies (resulting in longer project timelines);
- Changes in labour force availability (job action, higher than anticipated retirement rates, changes in the contractor community);
- Actions of HONI or the IESO (e.g. outage coordination challenges);
- Other related circumstances.

While these activities can have a significant affect on Toronto Hydro's ability to implement certain programs or projects in any specific year, that potential impact is significantly reduced over a longer (five-year) timeframe, providing the utility sufficient flexibility to adjust the pace on the affected projects, while redeploying its resources towards the work that can be completed in the immediate term. The aggregate five-year target ensures that the utility will work towards delivering the entirety of the capital program approved for the 2015-2019 planning period.

C3.1.2 Historical Performance Trends

The proposed 2015-2019 Distribution System Plan is the first time that Toronto Hydro expects to implement an approved medium-length multi-year capital plan. Accordingly, the utility is not in a position to provide the comparable historical results in a similar format, in light of the variety of circumstances under which Toronto Hydro's capital plans for 2009 through 2014 were prepared, amended and subsequently reviewed and approved by the OEB.

C3.1.3 Interaction with the Distribution System Plan

The proposed plan implementation progress measure is expected to allow Toronto Hydro and the OEB to gauge the utility's progress towards the completion of its entire 2015-2019 capital plan at

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 24:

Reference(s): **Exhibit 2B**

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

a) Please explain how Toronto Hydro will kept accountable for the approved rate increase in any given year if approval is granted to move capital projects from one year to another? What type of detailed reporting does Toronto Hydro plan to provide regarding its capital program?

RESPONSE:

As explained in Toronto Hydro's responses to interrogatories to 2A-CCC-23 and 2B-OEBStaff-39, the substitution, deferral or advancement of particular projects occurs in the ordinary course of Toronto Hydro prudently executing its capital work program. Toronto Hydro has detailed throughout this application (see, for example, Exhibit 1B, Tab 2, Schedule 4, pages 13-14), in prior rate applications (e.g., EB-2012-0064) and in its 2013 OEB Scorecard, how a variety of external factors regularly require changes to the timing of Toronto Hydro's capital plans and forecasts for specific work. These factors /C

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

include work permit timing, weather and re-prioritization of jobs due to system needs. In many of these situations, good utility practice and prudent work planning is best served by: (a) specific projects within a capital program being substituted, on a like-for-like basis, with other projects; or (b) specific projects being added to a given program, accelerated or deferred. These numerous external factors mean that Toronto Hydro cannot with certainty plan in advance execution timing or costs, and attempting to do so would actually be an imprudent use of time and ratepayer funds. Operationally, it is in Toronto Hydro's interests to maintain a smooth flow of work rather than having abrupt changes in work levels. Toronto Hydro has prepared a detailed overview of the practical execution challenges that the utility often faces during development and execution of its capital program. This overview can be found in Exhibit 1B, Tab 2, Schedule 4, Appendix A ("Execution Challenges").

As detailed in Exhibit 1B, Tab 2, Schedule 6, Toronto Hydro's proposes annual reporting on its capital program that consists of: (a) meeting the OEB's Scorecard Approach for Performance Measurement; and (b) reporting on the proposed Performance Measures Framework as described in the above-noted reference and its DSP (Exhibit 2B, Section C). Toronto Hydro proposes that these metrics and measures will assist the OEB and intervenors in monitoring the utility's performance outcomes.

For example, per its 2013 OEB Scorecard, Toronto Hydro deems its year-end capital program results to be successful if the year-end results are within +/- 20% of the approved CAPEX amount.

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.

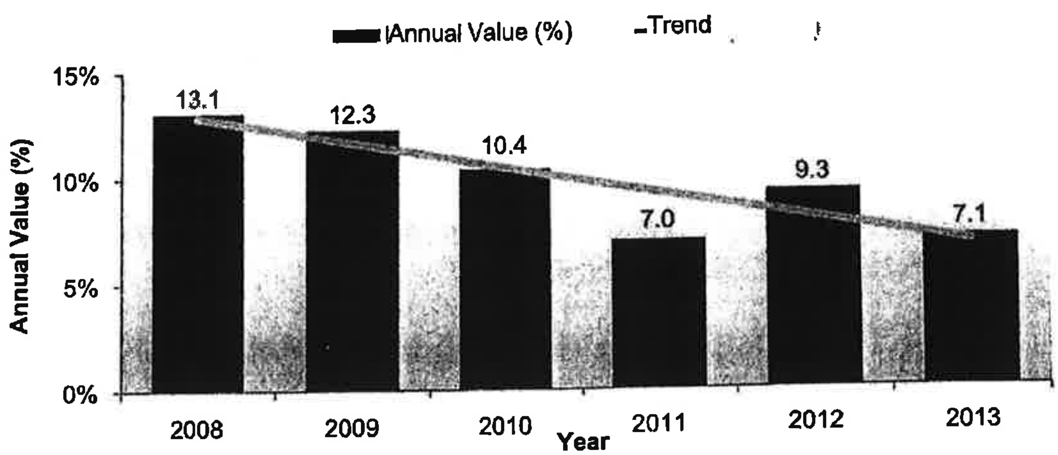

FIGURE 9: INDIRECT LABOUR % OF DX PLANT EXPENDITURES – 2009-2013

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.

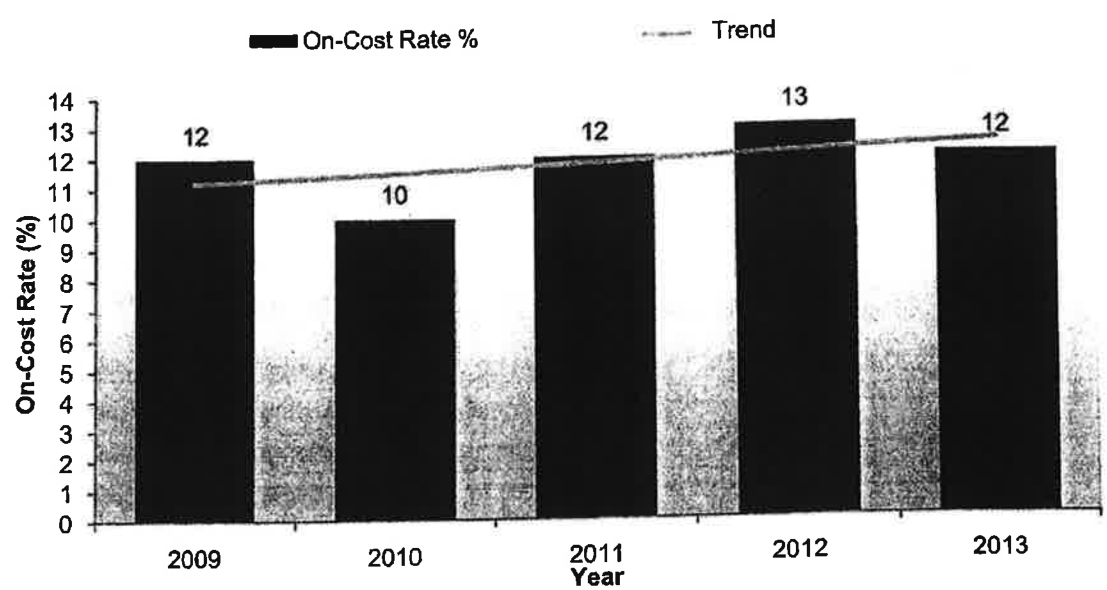

FIGURE 10: ON-COST PERFORMANCE (%) – 2009 – 2013

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.

C3.4 Construction Efficiency: Internal vs. Contractor Cost

C3.4.1 Measure Description

To assess the reasonableness of the costs of capital construction projects completed by the utility's internal construction crews, Toronto Hydro compares the cost of select projects constructed "in-house" to the unit prices charged for similar work performed by external contractor crews. Toronto Hydro currently employs six full-service design and construction contractors that provide the utility with turnkey electrical project design and construction services. This service enables the utility to complete the requisite volume of capital work in a safe and efficient manner, while providing the resourcing scalability and flexibility to account for the changing capital program funding levels.

When presented with individual project designs, contractors break down each project into the number and type of applicable activity-based units, which are based on Toronto Hydro's certified Distribution Construction Standards. The aggregation of unit prices determines the total price that the contractors are paid for delivering the project. As such, contractors are ultimately responsible for managing the variances between the unit cost estimate and their actual costs.

Once properly adjusted for the differences in cost structures between Toronto Hydro's operations and those of external contractors, the comparative results show Toronto Hydro the cost gap between internally and externally executed projects. Given that Toronto Hydro's external contractors operate in the same environment as the utility's internal crews, and use materials paid for and procured by the utility, comparisons between the costs of externally and internally constructed projects constitute an appropriate form of construction cost benchmarking. Operating in the Canadian and Toronto construction markets, the cost structures of Toronto Hydro's external contractor partners must reflect the optimal efficiency levels across both its operating and support activities in a competitive market. Accordingly, the unitized cost estimates provided to Toronto Hydro by its construction partners at the time of contract negotiation reflect the competitive market costs to complete the projects of the scope, scale and complexity characteristic of Toronto Hydro's aging and dense urban distribution system.

C3.4.1.1 Comparison Methodology

Beginning in 2011, each year Toronto Hydro selects up to ten reference capital projects constructed by its internal crews over the previous year. To date, the projects have been selected from three of the utility's larger capital portfolios, namely Direct Buried Cable Replacement, Overhead and Underground Rehabilitation. To establish a consistent baseline for cost comparison, the selected internally delivered projects have minimal cost and scope variations from the original design.

The reference project design packages are divided among several of Toronto Hydro's participating contractors, who disaggregate them into individual units. To better reflect the range of contractor costs available to Toronto Hydro, the utility applies the unit costs of all six contractors to the number and type of units identified for each project. This provides Toronto Hydro with six unique contractor cost estimates for each of the ten reference projects.

Prior to undertaking comparisons, Toronto Hydro's actual project costs and the contractor estimates require adjustments to account for a number of differences inherent in the respective entities' business models. The most significant of these adjustments is necessitated by the fact that Toronto Hydro's capital costs do not capture the full extent of the utility's expenses, as a significant portion of the utility's costs is recovered through the OM&A expenditures and other means of cost recovery available to regulated distributors in Ontario. At the same time, Toronto Hydro assumes that the contractors must recover and earn profit on the entirety of their operating activities through the prices charged for project delivery. To correct for this important distinction, Toronto Hydro's capital costs require adjustments to include the relevant overhead, burden and regulated return components.

In performing the above adjustment Toronto Hydro accounts for the fact that it performs a number of functions which the contractors do not perform at all (e.g. feeder switching), or which they perform on a smaller scale than the LDCs (customer care, finance, HR, etc). Because of these distinctions, certain components of Toronto Hydro's overhead and burden costs are either explicitly excluded from the capital cost adjustment, or are proportionally allocated to reflect the costs associated with Toronto Hydro's internally executed capital construction costs. The end product of the adjustment process is an all-in cost estimate of Toronto Hydro's construction costs for internally executed projects, inclusive of all the relevant support functions that may not be intuitively associated with construction. In other words, the resulting adjusted estimate represents a approximation of a hypothetical price that Toronto Hydro would charge its customers if it were a design and construction-only utility, as opposed to a regulated distributor.

In a similar manner, contractor project estimates require adjustments to account for the project-related cost drivers that are incremental to their project costs, including costs of audit and verification mandated by Toronto Hydro, and administration charges from the utility's Program Support Office that manages the design and construction contractors. After the completion of the adjustment process, Toronto Hydro's reference project costs are reasonably comparable to the contractor estimates..

C3.4.2 Historical Performance Trends

Based on the above comparison methodology, the costs of Toronto Hydro's internal project construction were on average [redacted] higher[3] than the costs of the same projects had they been constructed by the six design and construction contractors. The cost gap value was calculated using the weighted average of individual estimate variances commensurate to the proportion of external contract work performed by each of the six contractors in a reference year.

Toronto Hydro's analysis indicates that a significant portion of fully burdened construction cost variance stems from the higher overhead and burden expenditures associated with the scale and scope of the utility's operations as compared to the analogous cost drivers for the external contractors. Some of these costs are driven by the terms of Toronto Hydro's collective agreements and by the need for Toronto Hydro to have specialized trades to work on unique aspects of its distribution system (downtown network, lead cable, box construction etc.). Contractors, on the other hand, generally employ high voltage workers with generic qualifications and experience needed for more standard overhead and underground systems most prevalent across their customer base. However, with respect to other cost drivers, such as facilities expenditures and the On-Cost rate, Toronto Hydro anticipates overall improvement due to the planned or ongoing productivity and efficiency initiatives. For the purposes of the 2015-2019 CIR period, Toronto Hydro will use the results of its historical analysis as a general point of reference. The utility notes, however, that it has recently issued a Request for Proposals (RFP) with the goal of awarding and re-negotiating its contracts with all external design and construction service providers for the 2015 – 2018 timeframe. The outcomes of the RFP may materially affect the results of future comparative efforts relative to the past year assessments. This is especially relevant in light of the high demand for qualified services currently characterizing Toronto Hydro's electrical construction market, and expected to remain a significant factor in the medium term. This is primarily due to a large number of construction projects planned or underway in the city

[3] The redacted information has been filed confidentially pursuant to the OEB's *Practice Direction on Confidential Filings*

including the residential high rise real estate developments, the PanAm/ParaPan Games construction, waterfront redevelopment, major transportation projects, and outsourcing work undertaken by other utilities.

C3.4.3 Interaction with the Distribution System Plan

Toronto Hydro uses the results of its external project construction cost benchmarking as a general reference for the reasonableness of the cost of projects completed by the utility's internal construction crews. As the utility continues conducting these comparative exercises over the 2015-2019 planning horizon, it may undertake more detailed assessments of individual cost drivers that make up the cost gap between contractor-delivered and internally constructed projects. At present, Toronto Hydro does not plan to expand the scale of this annual comparative activity, in part because of the complexity of conducting these assessments.

C3.5 Construction Efficiency: Standard Asset Assembly Labour Inputs

C3.5.1 Measure Description

Toronto Hydro is in the early stages of investigating the possibility of developing a comprehensive framework for tracking the total number of labour hours required to stage, install and energize a fully assembled unit corresponding to each major asset class of the utility's electricity distribution plant (e.g. transformers, switchgear etc). The project's envisioned scope entails developing a framework of about 25 major "Asset Assemblies," which in aggregate account for over 80% of the utility's planned capital program executed by internal resources.

At present, Toronto Hydro's engineers and designers use a fragmented framework of over 180 discrete labour activity cost estimates to prepare project scopes and develop associated designs, by taking into account the varying job-specific field conditions and circumstances that impact installation timeframes. While this framework enables Toronto Hydro to prepare extremely detailed cost estimates, it is not optimally suited for easy and effective tracking in the field by the utility's crews conducting the work. Accordingly, Toronto Hydro's objective is to augment the existing system with a more uniform, yet sufficiently flexible, labour hours input framework that would meet all of Toronto Hydro's planning, design and project tracking needs.

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While the project is currently in an early testing stage, the envisioned end-state scope includes about 25 discrete estimates of total labour and "non-wrench" hours (e.g. driving, set-up/take-down, breaks) required to fully complete a single installation of a major asset class unit. The estimates of total hours will be developed based on system averages derived through analysis of past results, pilot time studies, and other activities determined as necessary during the subsequent project stages. To provide the requisite flexibility and scalability in light of the diversity of conditions and configurations inherent in Toronto Hydro's distribution system, the core Asset Assemblies framework will be augmentable through a standardized and centrally managed set of Project Adjustment Factors. These additional estimate adjustment capabilities are expected to allow the engineers and designers to customize the expected project completion estimates to account for specific engineering, topographic or other related circumstances applicable to each individual project.

To faciliate the core labour and non-wrench hours estimates continuing to reflect the reality of field conditions, the underlying numbers will undergo periodic updates on the basis of actual results obtained from the field. This periodic update process is expected to effectively create a positive feedback loop, allowing Toronto Hydro to reflect the emerging improvements in crew productivity levels in its future estimates. This process will enable Toronto Hydro to maintain realistic capital construction targets and foster a culture of continuous improvement. To enable effective day-to-day tracking of project progress by individual construction crews, the project scope includes the development of a user-friendly IT application for use on handheld devices issued to crew leaders.

Toronto Hydro chose to focus on labour input hours rather than any other units (e.g. dollars), because labour hours are a commodity that is not affected by inflation, is generally comparable across the utility's field resources, and has inherent potential for improvement through adoption of more efficient work execution practices and the introduction of new tools or other process improvements.

C3.5.2 Historical Performance Trends

Toronto Hydro is in the early stages of the Asset Assemblies project implementation and testing, so the utility does not have any historical results associated with this measure.

C3.5.3 Interaction with the Distribution System Plan

Given the early stages of what Toronto Hydro estimates to be a three-year project implementation timeline, Toronto Hydro's tracking of this measure will amount to annual updates on the project status, based on the following anticipated timeline:

- 2015-2016: develop and test the conceptual framework and implement the tracking system;
- 2017-2018: collect actual data and establish initial labour and non-wrench time benchmarks;
- 2019: begin reporting on performance related to a subset of specific Asset Assemblies.

While Toronto Hydro acknowledges that the above project tracking schedule is general in its nature, the utility is not in a position to provide a more detailed schedule at this time. Accordingly, Toronto Hydro plans to provide more detailed project development schedule forecasts with each annual update. Once Toronto Hydro is in a position to track the adherence to specific labour targets for Asset Assemblies completion, it plans to track approximately three to five individual asset categories for the purposes of any single Distribution System Plan performance measurement.

More generally, Toronto Hydro anticipates that the successful implementation of the Asset Assemblies framework will allow the utility to effectively benchmark its internal construction inputs (and by extension costs), thus driving continuous improvement. Among other things, the Asset Assemblies labour hours tracking framework may prove to be a useful way to inquire further into the utility's internal labour costs as compared to the results of benchmarking of its internal construction costs to the prices charged by the external construction contractors (See Section C3.4).

C4 ASSET & SYSTEM OPERATIONS PERFORMANCE

C4.1 Outages Caused By Defective Equipment

C4.1.1 Measure Description

For the purposes of measuring the performance of its equipment over the 2015-2019 planning horizon, Toronto Hydro plans to track the number of outages occurring over a rolling 12-month period due to defective or otherwise malfunctioning equipment. These outages are distinct from other outage causes such as vegetation/animal contacts, upstream supply interruptions or weather-related events. On average over the past five years, defective equipment-related outages were responsible for approximately 44% of total SAIDI and 41% of SAIFI results. Toronto Hydro tracks its equipment-related outages using ITIS, where each event is assigned a specific cause code. The count or number of outages caused by failed equipment speaks to the general condition of the utility's assets. Toronto Hydro proposes to track the number of equipment related-outages on a rolling 12-month basis.

C4.1.2 Historical Performance Trends

Figure 11 provides a summary of Toronto Hydro's historic performance on the equipment-related outages measure over the 2009-2013 timeframe. As seen in the chart, Toronto Hydro's performance on this measure has steadily improved over the past five years from 728 events in 2009 to 636 in 2013 – an improvement of over 11%. The utility attributes this performance improvement to the high level of System Renewal investments made in recent years, but notes that as with SAIDI and SAIFI, improvements in the defective equipment-caused outages often lag behind the investments to rectify them by several years. Accordingly, to maintain and/or improve on the current trend, Toronto Hydro plans to continue investing in System Renewal and other programs facilitating equipment performance improvements.

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	41.1%	44.3%
Unknown	12.0%	2.6%
Loss of Supply*	9.6%	5.9%
Foreign Interference	9.3%	9.4%
Tree Contacts	9.0%	12.8%
Adverse Weather	8.7%	11.3%
Lightning	3.5%	5.2%
Scheduled Outage*	3.2%	6.2%
Human Element	2.7%	1.0%
Adverse Environment	0.8%	1.3%

* Excluded from typical system analysis when demonstrating the true condition of THESL's system

Between 2009 and 2013, defective equipment was the main contributor to SAIFI and SAIDI, at 41.1% and 44.3% respectively. As shown in Figures 10 and 11, the majority of improvement in SAIFI and SAIDI in 2013 over the previous years is in Defective Equipment and, to a lesser extent, Adverse Environment and Lightning. Outages due to Adverse Environment and Lightning are typically not reflective of the condition of the assets in the system, but rather the environmental stresses that the assets experience. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system, and tracks this cause code as a measure of continuous improvement over the course of its capital expenditure and maintenance plans. Additional analysis of various relevant cause codes is provided below.

5.1. Weather Impacts

Three cause codes can generally be combined to reflect weather impacts on the system:

(a) Adverse Weather,

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES

INTERROGATORY 21:

Reference(s): **Exhibit 2A, Tab 10, Schedule 2 Page 11 Table 2**

Preamble:

Table 2 provides the percentage contribution of Defective Equipment to SAIFI & SAIDI.

a) Please provide a further breakdown of the causes of Defective Equipment that make up the percentages shown in Table 2.

RESPONSE:

a) Please see table below:

Equipment	Contribution % to SAIFI	Contribution % to SAIDI
Underground Cables	39.3%	39.5%
Poles and Pole Hardware	21.1%	19.5%
Switches	16.4%	11.4%
Overhead Conductors	7.7%	6.9%
Others	6.6%	6.4%
Transformers	5.0%	7.7%
Stations Equipment	3.8%	8.6%

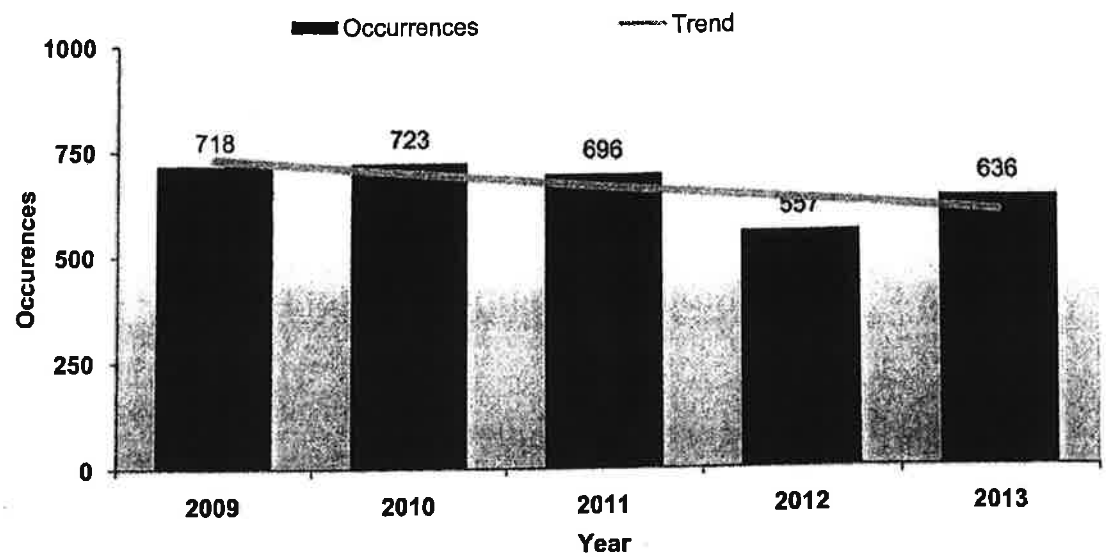

FIGURE 11: OUTAGES CAUSED BY DEFECTIVE EQUIPMENT – 2009-2013

C4.1.3 Interaction with the Distribution System Plan

As stated above, Toronto Hydro attributes performance improvement as illustrated in Figure 11 to the level of System Renewal investments made in recent years, but notes that given the current system demographics, continued focus on the system renewal investments is required to avoid a reversal of this trend.

Toronto Hydro plans to continue improving the general health of the system assets and ensure the historical trend continues so as to improve the system reliability. Given the proposed levels of System Renewal investments in its 2015-2019 Distribution System Plan, Toronto Hydro anticipates that the number of defective equipment-related outages will improve in line with the expected improvement in asset demographics. As a pure failure metric that does not consider imact and duration, the trajectory of this metric is expected to be affected by system renewal but not significantly changed by modernization. Overall, Toronto Hydro expects the historic trend to continue during the 2015-2019 period.

The results of this measure will inform Toronto Hydro as to the effectiveness of its asset replacement strategies and preventive maintenance activities. Should the results over the future years display trends significantly different from the historical levels, Toronto Hydro plans to investigate the underlying reasons and make the appropriate adjustments as necessary and feasible. Customers that are interrupted due to failed equipment can typically expect extended outages as Toronto Hydro crews replace the failed asset. By reducing the volumes of equipment at risk of failure across its system, Toronto Hydro will be assisted delivering more reliable system performance to its customers.

C4.2 Stations Capacity Availability

C4.2.1 Measure Description

As its final performance measure for the purposes of its 2015-2019 Distribution System Plan, Toronto Hydro proposes to track the availability of capacity at its Transformer Stations (TS). The utility regularly monitors its available station capacity across the service territory to ensure that sufficient capacity exists to satisfy system peak demand, accommodate new customer connections, and provide a reasonable amount of operating flexibility to the Control Centre for the purposes of load transfers. These monitoring activities enable the planned and reactive capital and maintenance work, and facilitate outage restoration efforts.

Toronto Hydro forecasts station-specific demand on an annual basis and compares the forecasts against the available equipment capacity. Where forecasts indicate potential capacity shortages, Toronto Hydro develops and executes the plans to transfer the incremental load to adjacent stations or increase the existing equipment's capacity. Given the pace of the recent and projected economic growth across the utility's service territory, stations capacity monitoring represents a crucial dimension of Toronto Hydro's asset management activities.

For the purposes of the 2015-2019 Distribution System Plan performance monitoring, Toronto Hydro proposes to track the number of stations where peak demand exceeds 90% of station capacity over the next five years. Given that a number of station expansion activities are currently underway (including construction activities at Copeland TS), Toronto Hydro proposes to track this measure based on a five-year rolling outlook starting in 2015. Since Toronto Hydro is not always in a position to unilaterally affect the station capacity limitations (e.g. due to upstream transmission system constraints), the utility proposes to narrow the scope of this measure to include the stations where capacity limitations are at the station bus and/or switchgear level.

C4.2.2 Historical Performance Trends

Figure 12 shows the historical data for the proposed Stations Capacity measure for the 2009-2013 period. As evidenced by the chart, the number of stations with capacity limitations has increased from three to five over 2009-2013, with a historical high of six stations in 2011-2012. This trend reflects ongoing load growth and new connections throughout the city. Over the time period shown, no new stations or additional station busses have been put into service. The metric drops from 2012 to 2013 primarily as a result of load transfer projects that have been planned since the 2013 load forecast was issued.

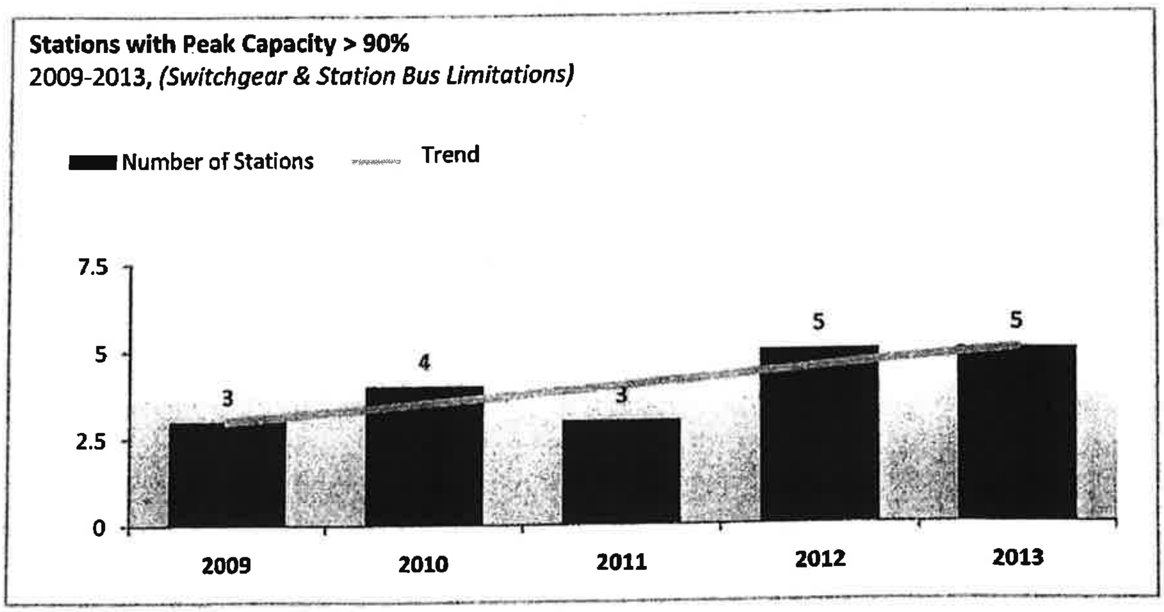

FIGURE 12: STATIONS WITH PEAK CAPACITY > 90% – 2009-2013, (SWITCHGEAR & STATION BUS LIMITATIONS)

C4.2.3 Interaction with the Distribution System Plan

Tracking the number of stations with peak capacity exceeding 90% will allow Toronto Hydro to gauge the effectiveness of its capacity planning processes and the timeliness of the associated constraint mitigation measures, including permanent load transfers, capacity increases, targeted CDM programs and other related activities. The Station Expansion Program specifically targets stations at which peak demand is approaching available capacity through upgrades and expansion of station infrastructure. The Load Demand program also aims to mitigate capacity shortfalls by balancing station bus loading through permanent load transfers.

Over the course of the 2015-2019 period, Toronto Hydro expects the measure and associated trend to remain generally constant, or potentially trend further upward, as more station busses approach their peak demand. Toronto Hydro's ability to maintain this trend is closely linked with the Station Expansion (E7.9) and Load Demand (load transfers) (E5.4) programs, which are expected to alleviate the most pressing concerns and add flexibility to the system to enable us to balance load between stations. Absent the investment levels proposed in either of these two programs, the measure would trend upward at a significantly higher pace.