EB-2019-0082

Hydro One Networks Inc.

Application for electricity transmission rates for the period from January 1, 2020 to December 31, 2022

AMPCO Compendium

Panel #1

Hydro One's proposed Custom IR components, therefore, contain both OEB-approved components and other mechanisms that are designed to align the utility's needs with the interests of its customers.

5. HYDRO ONE'S TRANSMISSION BUSINESS PLAN

Hydro One's 2019-2024 Transmission Business Plan on which this Application is based will deliver the following outcomes:

- Optimizing the cost and performance of the existing assets through maintenance and renewal projects;
- Improving system and customer reliability to restore top quartile reliability performance as compared to the company's Canadian peers. In 2018, Hydro One's transmission reliability performance decreased from top quartile to 2nd quartile due to major storms and increased equipment-caused interruptions;
- Addressing customer needs and preferences through new customer connections, and regional development to enable growth and through system renewal to meet current requirements;
- Responding to customer power quality concerns by proactively monitoring power quality across the province and working with customers to resolve specific issues; and
- Incorporating productivity savings totalling approximately $370 million over the test period to offset the customer rate impacts of the proposed Business Plan.

Based on Hydro One's assessment of its transmission system, a significant portion of the assets are reaching the end of their useful life and have deteriorated to the point where investment is required to maintain customer reliability and meet safety and environmental sustainability requirements. A safe and reliable transmission system is essential to

- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision making processes in managing the transmission assets.

A summary of Hydro One's Sustainment OM&A expenditures for (i) the 2020 Test Year; (ii) the 2019 Bridge Year; and (iii) the 2015-2018 historical period is provided in Table 1 below.

Table 1: Summary of Sustainment OM&A ($ Millions)

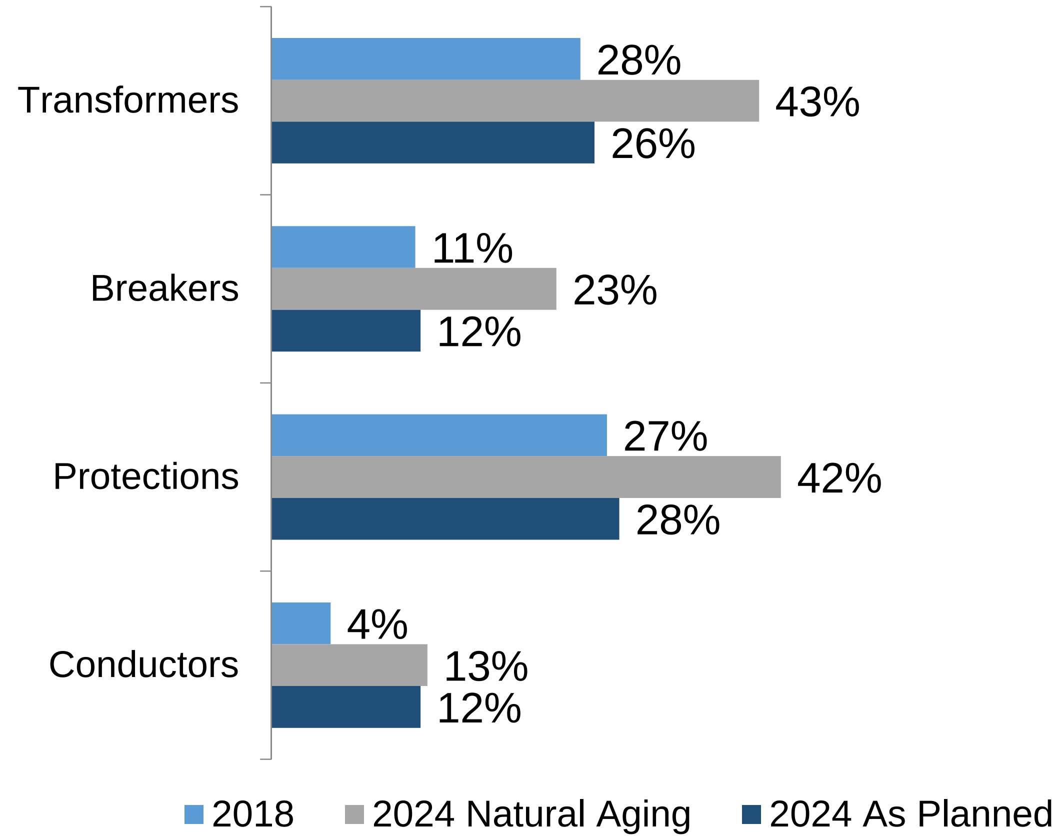
Description	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Stations	175.0	169.0	159.3	171.6	162.7	178.5	161.4	174.8	145.7	155.4
Lines	52.6	57.8	51.4	58.8	51.5	59.8	63.8	60.8	47.7	53.4
Engineering and Environmental Support	6.0	11.9	4.4	10.8	4.0	2.9	4.1	2.9	7.2	5.3
Total Sustainment	**233.6**	**238.7**	**215.1**	**241.1**	**218.1**	**241.2**	**229.4**	**238.5**	**200.6**	**214.2**

2. VARIANCE EXPLANATION FOR SUSTAINMENT OM&A

The "Plan" values shown in Table 1 above reflect the funding levels previously proposed by Hydro One in its rate applications to the OEB for the applicable years. As explained in Exhibit F, Tab 1, Schedule 1, for the historical years these values have not been adjusted or revised to reflect the OEB's final rate decisions.

ASSET DEMOGRAPHICS

Hydro One is making targeted investments driven by asset condition



Asset Type	Assets at High or Very High Risk (%)	
	EB-2016-0160 2017-2018	EB-2019-0082 2020-2022
Transformers	15%	17%
Circuit Breakers	11%	9%
Protection Systems	27%	27%
Conductors	9%	13%

hydro one

UNDERTAKING - JT 1.21

Reference:

I-11-CCC-004

Undertaking:

To provide the underlying numbers for the two charts to derive the amounts.

Response:

a) The following table outlines the portion of Hydro One's major assets that had a high or very high risk condition and were considered to be end of life at the time of filing Application EB-2016-0160.

Hydro One has amended the table below (emphasis added) presented in Interrogatory I-CCC-004 part b) and originally provided in EB-2016-0160 Exhibit B1, Tab 2, Schedule 6, Figure 30 to reflect a correction to the calculation of High Risk or Very High Risk Wood Poles. Further details may be found at Undertaking JT 1.22.

Major Asset Condition Summary

Asset Type	% of Assets at High or Very High Risk	Count of Assets at High or Very High Risk	Total Population	EB-2016-0160 Reference
Transformers	15%	108	721	Exhibit B1, Tab 2, Schedule 6, Figure 5
Circuit Breakers	11%	499	4,543	Exhibit B1, Tab 2, Schedule 6, Figure 11
Protection Systems	27%	3,267	12,103	Exhibit B1, Tab 2, Schedule 6, Figure 18
Conductors (km)	9%	2,643	29,369	Exhibit B1, Tab 2, Schedule 6, Figure 24
Wood Poles	*12%*	*4832*	42,000	Exhibit B1, Tab 2, Schedule 6, Figure 30
Underground Cables (km)	4%	11	267	Exhibit B1, Tab 2, Schedule 6, Figure 48

Witness: Donna Jablonsky

b) The following table outlines the portion of Hydro One's major assets included in this Application that have a high or very high risk condition and are considered to be at end of life.

Major Asset Condition Summary

Asset Type	% of Assets at High or Very High Risk	Count of Assets at High or Very High Risk	Total Population	EB-2019-0082 Reference
Transformers	17%	122	716	Exhibit B, TSP Section 2.2, Table 1 Exhibit B, TSP Section 2.2, Figure 3
Circuit Breakers	9%	460	4,774	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 8
Protection Systems	27%	3,363	12,506	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, p 26
Conductors (km)	13%	3,680	29,107	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 18
Wood Poles	13%	5,630	42,000	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 27
Underground Cables (km)	3%	8	264	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 21

UNDERTAKING - JT 1.24

Reference:

I-07-SEC-036

Undertaking:

To provide actuals for the table in SEC IR 36 under the column EB-2019-0018.

Response:

Please refer to the updated interrogatory I-07-SEC-036 provided as Attachment 1 which includes 2016 actuals as well as updated actual and forecast expenditures for the station centric assets (transformers, breakers and protection systems) for 2017-2022.

Furthermore, historical replacement units have been updated to reflect a correction to actuals reported. For 2018 this was due to a lag in reporting of in-serviced units that were not accounted for when the Application was filed on March 19, 2019.

To provide consistency, Table 3 and 4 from Exhibit B-1-1 TSP Section 3.3 showing the replacement units have been updated to reflect unit updates provided in this undertaking J1.24 (I-7-SEC-36) and undertaking J1.26 (I-12-AMPCO-28)

Table 1: Asset Replacement Rates - Transmission Station Assets

	Historical				Bridge	Test			Plan	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Transformer Portfolio										
# of Replacements	24*	18*	15	28*	20	9	23	19	40	17
% of Fleet	3.3%	2.6%	2.1%	3.6%	2.8%	1.3%	3.2%	2.7%	5.6%	2.4%
Circuit Breaker Portfolio										
# of Replacements	31	73	108	155*	88	135	105	88	215	95
% of Fleet	0.7%	1.6%	2.4%	3.2%	1.9%	2.8%	2.2%	1.9%	4.5%	2.0%
Protection Systems Portfolio										
# of Protection Replacements	445	627	298	325*	453	465	370	503	681	384
% of Fleet	3.6%	5.1%	2.5%	2.6%	3.6%	3.7%	3.0%	4.0%	5.4%	3.1%

Witness: Donna Jablonsky

1 **Table 2: Asset Replacement Rates - Transmission Line Assets**

	Historical				**Bridge**	**Test**			**Plan**	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Conductor Portfolio										
kms of Circuit Replacements	201	183	119	51	140	64	483	795	309	475
% of Fleet	0.7%	0.6%	0.4%	0.2%	0.5%	0.2%	1.7%	2.7%	1.1%	1.6%
Wood Pole Portfolio										
# of Replacements	845	761*	966*	735*	560	800	800	800	800	800
% of Fleet	2.0%	1.8%	2.3%	1.8%	1.3%	1.9%	1.9%	1.9%	1.9%	1.9%
Steel Structure Portfolio										
# of Renewal	371*	86*	725	1050	220	260	500	500	500	500
% of Fleet	0.7%	0.2%	1.4%	2.0%	0.4%	0.5%	1.0%	1.0%	1.0%	1.0%
Insulator Portfolio										
# of circuit structures	155	2100	3623*	3958*	3700	3700	3700	3450	3450	3450
% of Fleet	0.1%	1.4%	2.6%	3.1%	2.9%	2.9%	2.9%	2.7%	2.7%	2.7%
Underground Cable Portfolio										
Kms of Circuit Replacements	0	2.3*	0	0	4.7	0	0	0	0	7.2
% of Fleet	0%	0.9%	0%	0%	1.8%	0%	0%	0%	0%	2.7%

2 **Replacements and percentage of fleet figures have been updated to reflect a correction to historical actuals. The 2017*
3 *and 2018 insulator figures reflect COB, CP and polymer insulator replacements.*

SEC-36

Please fill in the shadded cells

	EB-2016-0160 Application/Proposal (1)					EB-2016-0160 DR0**		EB-2019-0082						
	2014A	2015A	2016F	2017F	2018F	2017F	2018F	2016A	2017A	2018A	2019F	2020F	2021F	2022F
Transformer Portfolio														
# Replacements	24	24	19	27	22	27	22	18	15	28[+]	20	9	23	19
% of Fleet	3.3%	3.3%	2.6%	3.7%	3.1%	3.7%	3.1%	2.5%	2.1%	3.6%[+]	2.8%	1.3%	3.2%	2.7%
Capital ($M) ***	132.0	132.0	104.5	148.5	121.0	148.5	121.0	77.3	75.7	193.6	110.3	50.6	131.9	111.1
Circuit Breaker Portfolio														
# Replacements	83	31	43	66	132	66	132	73	108	155[+]	88	135	105	88
% of Fleet	1.8%	0.7%	0.9%	1.5%	2.9%	1.5%	2.9%	1.5%	2.4%	3.2%[+]	1.9%	2.8%	2.2%	1.9%
Capital ($M) ***	58.1	21.7	30.1	46.2	92.4	46.2	92.4	42.4	54.7	77.9	47.5	74.3	58.9	50.3
Protection Systems Portfolio														
# Replacements	610	266	367	449	528	449	528	627	298	325[+]	453	465	370	503
% of Fleet	5.0%	2.2%	3.0%	3.7%	4.4%	3.7%	4.4%	5.1%	2.5%	2.6%[+]	3.6%	3.7%	3.0%	4.0%
Capital ($M) ***	76.3	33.3	45.9	56.1	66.0	56.1	66.0	57.3	42.8	60.5	64.7	67.8	54.9	76.2
Conductor Portfolio														
Replacements (km)	93	201	183	192	440	192	440	183	119	51	140	64	483	795
% of Fleet	0.3%	0.7%	0.6%	0.6%	1.5%	0.6%	1.5%	0.6%	0.4%	0.2%	0.5%	0.2%	1.7%	2.7%
Capital ($M)	40.7	58.4	76.9	67.1	143.1	67.1	143.1	68.0	36.5	52.0	137.6	150.8	191.4	211.7
Wood Pole Portfolio														
# Replacements	897	845	850	850	850	935	850	761	966	735	560	800	800	800
% of Fleet	2.2%	2.0%	2.0%	2.0%	2.0%	2.2%	2.0%	1.8%	2.3%	1.8%	1.3%	1.9%	1.9%	1.9%
Capital ($M)	43.6	38.5	38.3	35.3	35.3	38.8	33.9	42.8	41.2	35.3	34.8	51.0	52.0	53.0
Steel Structure Portfolio[++]														
# Renewal	153[++]	371[++]	462	1250	1600	1145	1600	86	725	1050	220	260	500	500
% of Fleet	0.3%	0.7%	0.9%	2.4%	3.1%	2.2%	3.0%	0.2%	1.4%	2.0%	0.4%	0.5%	1.0%	1.0%
Capital ($M)	3.8	5.1	8.8	42.5	54.4	39.0	26.2	2.3	42.1	37.7	9.3	11.4	21.8	22.3
Underground Cable Portfolio														
Replacements (km)	3.1	0	0	0	4.8	0	4.8	2.3	0	0	4.7*	0	0	0
% of Fleet	1.1%	0.0%	0.0%	0.0%	1.8%	0.0%	1.8%	0.9%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%
Capital ($M)	20.6	3.5	1.4	2.3	22.5	2.3	22.5	1.7[+++]	10.7	16.5	15.0	7.1	32.5	33.6

Source: (1) EB-2016-0160 I-6-20

* Discrepancy is due to rounding

** EB-2016-0160 DRO Forecast reflects EB-2016-0160 Application/Proposal due to timing of Decision & Order. Revised units were not forecast as part of the DRO submission.

*** 2016A, 2017A and 2018A Capital expenditures reflect capitalized costs for station centric asset replacements (transformers, breakers and protection systems). Forecasts for 2019F and onwards reflect the 2016-2018A average cost including CPI (Exhibit B-1-1 TSP Section 2.1 page 11)

[+] Updated to reflect 2018 in-serviced units that were not accounted for, due to a lag in reporting, when the Application was filed

[++] Updated values to reflect correct accomplishments for 2014, 2015

[+++] Replacement cost included under a development project; not in the sustainment category

SEC-36; JT1.24

1					EB-2019-0082					
2		2016 A	2017A	2018A	TOTAL	2020F	2021F	2022F	TOTAL	Variance
3	**Transformer Portfolio ***									
4	# Replacements	18	15	28	61	9	23	19	51	
5	% of Fleet	2.5%	2.1%	3.6%		1.3%	3.2%	2.7%		
6	Capital ($M)	77.3	75.7	193.6	**346.6**	50.6	131.9	111.1	**293.6**	**-53.0**
7										
8	**Circuit Breaker Portfolio ***									
9	# Replacements	73	108	155	336	135	105	88	328	
10	% of Fleet	1.5%	2.4%	3.2%		2.8%	2.2%	1.9%		
11	Capital ($M)	42.4	54.7	77.9	**175.0**	74.3	58.9	50.3	**183.5**	**8.5**
12										
13	**Protection Systems Portfolio ***									
14	# Replacements	627	298	325	1250	465	370	503	1338	
15	% of Fleet	5.1%	2.5%	2.6%		3.7%	3.0%	4.0%		
16	Capital ($M)	57.3	42.8	60.5	**160.6**	67.8	54.9	76.2	**198.9**	**38.3**
17										
18	**Conductor Portfolio**									
19	Replacements (km)	183	119	51	353	64	483	795	1342	
20	% of Fleet	0.6%	0.4%	0.2%		0.2%	1.7%	2.7%		
21	Capital ($M)	68.0	36.5	52.0	**156.5**	150.8	191.4	211.7	**553.9**	**397.4**
22										
23	**Wood Pole Portfolio**									
24	# Replacements	761	966	735	2462	800	800	800	2400	
25	% of Fleet	1.8%	2.3%	1.8%		1.9%	1.9%	1.9%		
26	Capital ($M)	42.8	41.2	35.3	**119.3**	51.0	52.0	53.0	**156.1**	**36.8**
27										
28	**Steel Structure Portfolio**									
29	# Renewal	86	725	1050	1861	260	500	500	500	
30	% of Fleet	0.2%	1.4%	2.0%		0.5%	1.0%	1.0%		
31	Capital ($M)	2.3	42.1	37.7	**82.1**	11.4	21.8	22.3	**55.5**	**-26.6**
32										
33	**Underground Cable Portfolio**									
34	Replacements (km)	2.3	0	0	2.3	0	0	0	0	
35	% of Fleet	0.9%	0.0%	0.0%		0.0%	0.0%	0.0%	0.0%	
36	Capital ($M)	1.7	10.7	16.5	**28.9**	7.1	32.5	33.6	**73.2**	**44.3**
										445.6
	Source: (1) EB-2016-0160 I-6-20									

* Discrepancy is due to rounding

** EB-2016-0160 DRO Forecast reflects EB-2016-0160 Application/Proposal due to timing of Decision & Order. Revised units were not forecast part of the DRO submissi

***These capital expenditures are conducted for both the asset and station centric approach, estimated unit costs have been provided

"DRO" refers to "Draft Rate Order"

"DSP" refers to "Distribution System Plan".

"EAR" refers to the "Expenditure Authority Register".

"ECA" refers to "Economic Cost Adjustment", which is a government published index that reflects movements in a broad-based consumer-focused price index as well as "Environmental Compliance Approvals", which are issued by the Ministry of the Environment, Conservation and Parks.

"Elenchus" refers to "Elenchus Research Associates."

"ELT" refers to the Executive Leadership Team, which is Hydro One's most senior level of management.

"EOL" refers to "end of life".

"EPC" refers to "Engineer, Procure and Construct".

"EPRI" refers to the "Electric Power Research Institute", which is an independent, non-profit organization for public interest energy and environmental research that conducts research, development and demonstration projects. EPRI conducted several analyses on behalf of Hydro One which are provided as Attachments to Section 1-4 of the TSP (Exhibit B, Tab 1, Schedule 1).

"EPSCA" refers to the "Electrical Power Systems Construction Association" trade union.

"ERO" refers to the "Electricity Reliability Organization".

"ERP" refers to "enterprise resource planning" or "Emergency Response Plans".

"ESOP" refers to the "Employee Share Ownership Plan".

"ESL" refers to the "expected service life", which is the average time duration in years that an asset can be expected to operate under normal system conditions.

"ETS" refers to the "Export Transmission Service".

"FERC" refers to the American "Federal Energy Regulatory Commission".

AMPCO INTERROGATORY #25

Reference:
TSP-02-02 p.2 Figure 1

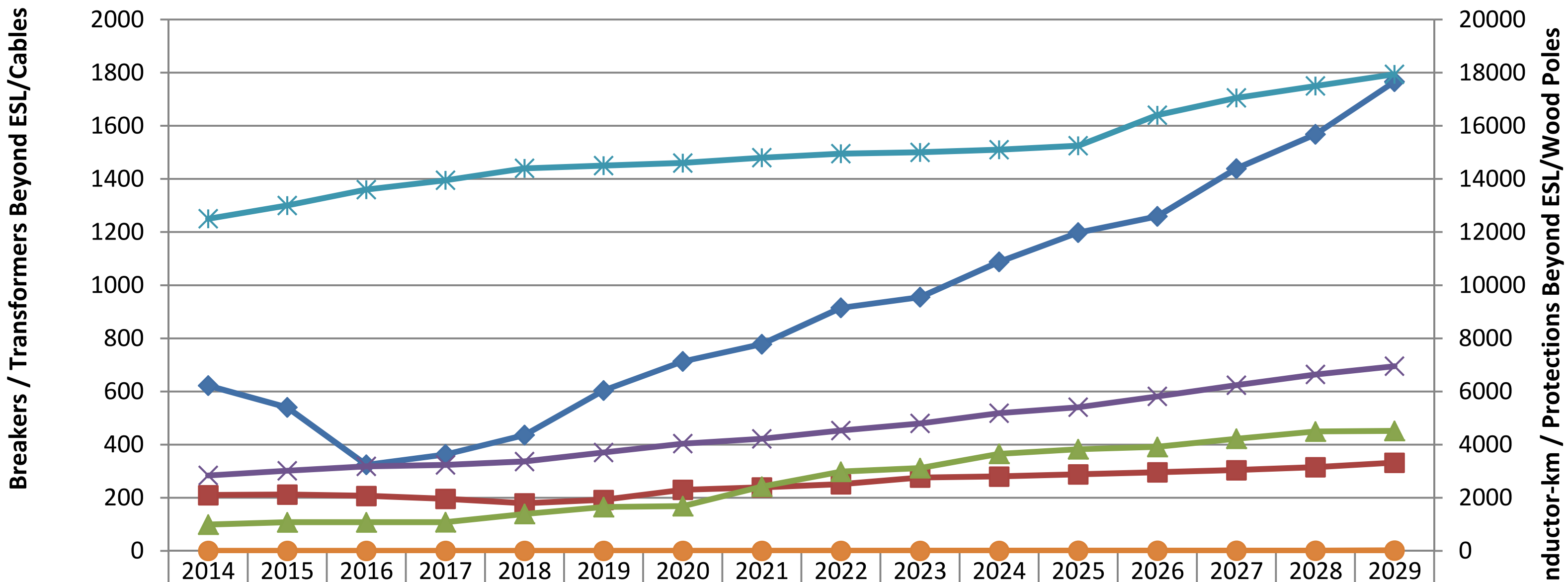
Interrogatory:
Please add the years 2014 to 2018 to Figure 1 and add wood poles and underground cable to Figure 1.

Response:
Table 1 below identifies the number of assets beyond ESL per year without replacement.

Witness: Donna Jablonsky

Table 1 - Number of Assets beyond ESL per Year Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	622	540	324	363	436	604	713	778	915	955	1088	1198	1259	1439	1568	1766
Transformers	210	212	207	196	179	192	230	239	251	276	280	288	296	304	315	332
Conductors[i]	988	1,076	1,077	1,078	1,389	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	2,839	3,017	3,180	3,234	3,363	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952
Wood Poles	12,500	13,000	13,600	13,950	14,400	14,500	14,600	14,800	14,950	15,000	15,100	15,250	16,400	17,050	17,500	17,940
Cables	0	0	0	0	0	0	0	2	4	4	4	6	6	7	7	17



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	622	540	324	363	436	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	210	212	207	196	179	192	230	239	251	276	280	288	296	304	315	332
Conductor	988	1,076	1,077	1,078	1,389	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	2,839	3,017	3,180	3,234	3,363	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952
Wood Poles	12,500	13,000	13,600	13,950	14,400	14,500	14,600	14,800	14,950	15,000	15,100	15,250	16,400	17,050	17,500	17,940
Cables	0	0	0	0	0	0	0	2	4	4	4	6	6	7	7	17

Breakers Transformers Conductor Protections Wood Poles Cables

[i] The beyond ESL population for conductors in 2014 to 2017 is provided by using the present ESL of 90 years for ACSR conductors (since 2018). Prior to 2018, ACSR conductors were assigned an ESL of 70 years.

AMPCO INTERROGATORY #26

Reference:
TSP-02-02 p.3 Table 1

Interrogatory:
a) Please add "Population" to Table 1.

b) Please provide an excel version of Table 1.

Response:
a) Please see the table below for Hydro One's major asset condition summary including population.

Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed	Total Population
Transformers	336	163	95	99	23	-	716
Circuit Breakers	2035	1475	804	293	167	-	4,774
Protection Systems	4,800	3,846	497	2,387	976	-	12,506
Conductors (km)	16,050		3,316	3,680		6,061	29,107
Wood Poles	-	17,640	0	5,460	-	18,900	42,000
Underground Cables (km)	-	179	77	8	-	0	264

** These categories are not used for all assets.*

b) Please refer to Attachment 1.

Witness: Donna Jablonsky

Major Asset Condition Summary							
Asset Type	**Very Low Risk***	**Low Risk**	**Fair Risk**	**High Risk**	**Very High Risk***	**To be Assessed**	**Total Population**
Transformers	336	163	95	99	23	-	716
Circuit Breakers	2035	1475	804	293	167	-	4,774
Protection Systems	4,800	3,846	497	2,387	976	-	12,506
Conductors (km)	16,050		3,316	3,680		6,061	29,107
Wood Poles	-	17,640	0	5,460	-	18,900	42,000
Underground Cables (km)	-	179	77	8	-	0	264

** These categories are not used for all assets.*

AMPCO INTERROGATORY #27

Reference:

TSP-02-02 p.3 Table 1

Interrogatory:

Please recast Table 1 using the Major Asset Condition data from EB-2016-0160 for each asset type.

Response:

Please see the table below for Hydro One's major asset condition summary from EB-2016-0160.

Major Asset Condition Summary

<table>
<tr><th>Asset Type</th><th>Very Low Risk*</th><th>Low Risk</th><th>Fair Risk</th><th>High Risk</th><th>Very High Risk*</th><th>To be Assessed</th><th>Total Population</th></tr>
<tr><td>Transformers</td><td>324</td><td>224</td><td>65</td><td>94</td><td>14</td><td>-</td><td>721</td></tr>
<tr><td>Circuit Breakers</td><td>2,272</td><td>1,090</td><td>681</td><td>454</td><td>45</td><td>-</td><td>4,543</td></tr>
<tr><td>Protection Systems</td><td>4,357</td><td>3,994</td><td>484</td><td>1,936</td><td>1,331</td><td>-</td><td>12,103</td></tr>
<tr><td>Conductors (km)</td><td colspan="2">11,748</td><td>5,874</td><td colspan="2">2,643</td><td>9,104</td><td>29,369</td></tr>
<tr><td>Wood Poles</td><td>-</td><td>29,820</td><td>8,400</td><td>1,260</td><td>-</td><td>2,520</td><td></td></tr>
<tr><td>Underground Cables (km)</td><td>-</td><td>195</td><td>59</td><td>11</td><td>-</td><td>3</td><td>267</td></tr>
</table>

** These categories are not used for all assets.*

Witness: Donna Jablonsky

Ref: I-12-AMPCO-027

EB-2016-0160 Major Asset Condition Summary											
Asset Type	**Very Low Risk***	**Low Risk**	**Fair Risk**	**High Risk**	**Very High Risk***	**To be Assessed**	**Total Population**	**Total H & VH Risk**	**%**	**Available Pop. Data**	**%**
Transformers	324	224	65	94	14	-	721	108	15%	721	15%
Circuit Breakers	2272	1090	681	454	45	-	4,543	499	11%	4,543	11%
Protection Systems	4,357	3,994	484	1,936	1331	-	12,103	3,267	27%	12,103	27%
Conductors (km)	11,748		5,874	2,643		9,104	29,369	2,643	9%	20,265	13%
Wood Poles	-	29,820	8400	1,260	-	2,520	42,000	4,832	12%	39,480	12%
Underground Cables (km)	-	195	59	11	-	3	267	11	4%	264	4%

** These categories are not used for all assets.*

								Targets					
Performance Outcomes	**Performance Categories**	**Measures**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Customer Focus	Customer Satisfaction	Satisfaction with Outage Planning Procedures (% Satisfied)	86	92	89	94	85	86	86	87	87	88	88
		Overall Customer Satisfaction (% Satisfied)	77	85	78	88	90	88	88	88	88	88	88
	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	11.8	14.3	9.7	9.5	10.1	12.0	11.7	11.5	11.3	11.0	10.8
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)	1.8	1.7	1.1	1.2	1.1	1.1	1.1	1.0	0.9	0.9	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)	0.60	0.59	0.46	0.65	0.83	0.55	0.54	0.53	0.52	0.51	0.50
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)	0.48	0.50	0.33	0.47	0.50	0.49	0.48	0.48	0.47	0.46	0.45
		T-SAIDI (Ave minutes of interruptions per Deliver Point)	36.7	43.9	80.8	42.8	70.0	35.4	34.66	33.96	33.28	32.62	31.97
		System Unavailability (%)	0.48	0.63	0.70	0.69	0.71	0.48	0.47	0.47	0.46	0.45	0.44
		Unsupplied energy (minutes)	12.2	11.8	11.4	13.2	19.5	9.8	9.59	9.40	9.21	9.02	8.84
	Asset & Project Management	Transmission System Plan Implementation Progress (%)	99	105	100	94	99	100	100	100	100	100	100
		CapEx as % of Budget	90	106	105	100	98	100	100	100	100	100	100
		OM&A Program Accomplishment (composite index)		97	99	108	108	100	100.0	100.0	100.0	100.0	100.0
		Capital Program Accomplishment (composite index)		122	59	88	116	100	100.0	100.0	100.0	100.0	100.0
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	8.4	9.0	8.6	7.9	7.7	7.3	7.8	7.9	7.7	7.3	7.0
		OM&A per Gross Fixed Asset Value (%)	2.7	2.9	2.5	2.3	2.3	1.8	1.8	1.7	1.6	1.5	1.5
		Line Clearing Cost per kilometer ($/km)	2,495	2,234	1,966	2,100	2,797	2,295	2,264	2,200	2,175	2,100	2,100
		Brush Control Cost per Hectare ($/Ha)	1,624	1,566	1,542	1,356	1,539	1,625	1,620	1,630	1,608	1,608	1,608
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments	100	100	100	100	100	100	100	100	100	100	100
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met, %	100	100	100	100	100	100	100	100	100	100	100
		End-of-Life Right-Sizing Assessment Expectation				Met	Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.69	0.13	0.20	0.13	0.12						
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.16	1.39	1.43	1.47	1.53						
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.36	9.30	9.19	8.78	9.00						
		Profitability: Regulatory Return on Equity — Achieved	13.12	10.93	10.02	9.03	11.08						

Figure 1 – Evolved Electricity Transmitter Scorecard & Targets – Hydro One Networks Inc.[4]

[4] Satisfaction with Outage Planning Procedures survey was not performed in 2013.The return on equity achieved values for 2013 to 2015 were restated.

AMPCO INTERROGATORY #18

Reference:
TSP-01-05 p.5

Interrogatory:

a) Please provide a copy of Hydro One's Transmission final Scorecard from EB-2016-0160.

b) Please provide a list of measures that are new to the scorecard compared to EB-2016-0160.

c) Please provide a list of measures that have been removed from the scorecard compared to EB-2016-0160 and explain why.

Response:

a) Hydro One proposed a Transmission Scorecard in EB-2016-0160, Exhibit B2-1-1, Attachment 1, p.2, replicated below as Figure 1. In the OEB's Decision and Order[1], the OEB did not consider it necessary to approve Hydro One's proposed Transmission Scorecard at that time and directed Hydro One to continue to develop its scorecard to reflect the Findings in the Decision and Order as related to the Transmission Scorecard. As such, Hydro One did not have a *final* Transmission Scorecard resulting from EB-2016-0160, but rather a draft Transmission Scorecard.

b) The following measure are new to the Evolved Electricity Transmitter Scorecard proposed by Hydro One in Exhibit B-1-1, TSP Section 1.5, p.5, Figure 1:

   a. Transmission System Implementation Progress (%)
   b. OM&A Program Accomplishment (composite index)
   c. Capital Program Accomplishment (composite index)
   d. Line Clearing Cost per kilometer ($/km)
   e. Brush Control Cost per Hectare ($/Ha)
   f. End-of-Life Right Sizing Assessment Expectation

[1] Decision and Order EB-2016-0160, Revised November 1, 2017, s.5.0 Productivity Improvements and Performance Scorecard, p.38

Witness: Bruno Jesus

c) The following measures were removed from the proposed Transmission Scorecard filed in EB-2016-0160:
    a. In-Service Capital Additions (% of OEB approved plan)
    b. Sustainment Capital per Gross Fixed Asset Value (%)
    c. NERC/NPCC Reliability Standards Compliance
        i. Number of High Impact Violations
        ii. Number of Medium/Low Impact Violations

These measures were removed from the proposed Transmission Scorecard in response to the OEB's Findings[2]. For a detailed explanation outlining the process for removing and replacing these measures and how Hydro One responded to the OEB's Findings regarding the Transmission Scorecard, please refer to Exhibit B-1-1, TSP Section 1.5, *Response to OEB Directions* from EB-2016-0160, pp.10-19.

[2] Ibid, p.39

Performance Outcomes	Performance Categories	Measures	Historical Years					
			2011	2012	2013	2014	2015	Trend
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)	Note 1	78	Note 1	86	92	▲
		Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	13.8	10.8	12.8	11.8	Note 2	▲
	Customer Satisfaction	Overall Customer Satisfaction in Corporate Survey (% Satisfied)	85	76	81	77	85	-
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Recordable Incident Rate (# of recordable injuries/illnesses per 200,000 hours worked)	3.7	2.3	2.5	1.8	1.7	▲
	System Reliability	T-SAIFI-S (Ave. # Sustained Interruptions per Delivery Point)	0.60	0.61	0.57	0.60	0.59	-
		T-SAIFI-M (Ave. # Momentary Interruptions per Delivery Point)	0.60	0.65	0.69	0.48	0.50	▲
		T-SAIDI (Ave. Minutes of Interruptions per Delivery Point)	127.9	71.5	66.0	36.6	44.3	▲
		System Unavailability (%)	0.50	0.48	0.37	0.48	0.66	▼
		Unsupplied Energy (minutes)	21.6	14.0	20.9	12.2	11.8	▲
	Asset Management	In-Service Capital Additions (% of OEB approved plan)	95	75	90	106	85	▲
		CapEx as % of Budget	78	81	73	90	106	▲
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	9.8	8.6	7.6	8.4	9.0	▲
		Sustainment Capital per Gross Fixed Asset Value (%)	2.6	2.8	3.3	4.2	4.6	Note 3
		OM&A per Gross Fixed Asset Value (%)	3.4	3.0	2.7	2.7	2.9	▲
Public Policy Responsiveness Transmitters deliver on obligations mandated by government. (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)	Connection of Renewable Generation	% on time completion of renewables connection impact assessments	100	100	100	100	100	-
	Market Regulatory Compliance	NERC/NPCC Reliability Standards Compliance						
		- Number of High Impact Violations (Note 4)	N/A	N/A	N/A	20	2	
		- Number of Medium/Low Impact Violations (Note 4)	N/A	N/A	N/A	5	10	
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met	N/A	N/A	N/A	100	100	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.24	0.29	0.80	0.69	0.13	
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio	1.27	1.22	1.10	1.16	1.39	
		Profitability: Regulatory Return on Equity — Deemed (included in rates) (%)	9.66	9.42	8.93	9.36	9.30	
		Profitability: Regulatory Return on Equity — Achieved (%)	10.95	12.41	13.22	13.12	10.93	

Note 1: Customer Satisfaction survey not done in 2011 and 2013.
Note 2: Results will be available in July 2016.
Note 3: In 2014 strategic decision made to increase sustainment capital.
Note 4: Results from 2011 to 2013 are excluded due to a lack of consistant data compared to 2014 and 2015.

Legend:
▲ up
▼ down
- flat

Figure 1 – Proposed Transmission Regulatory Scorecard – Hydro One Networks Inc., EB-2016-0160

Table 1: Proposed Transmission Scorecard

RRFE Principle	Category	Metric	*Definition*
Customer Focus	Service Quality	Satisfaction with Outage Planning Procedures	*% satisfied in OGCC survey*
		Customer Delivery Point Performance Standards Outliers (as % of total delivery points)	*% of total delivery points designated as outliers*
	Customer Satisfaction	Overall % satisfied in corporate survey	*Transmission customers (Industrial, Generators, LDC) only*
Operational Effectiveness	Safety	# of recordable incidents per 200,000 hours	*Average # of incidents per 200K hours*
	System Reliability	Average # of sustained interruptions per delivery point	*T-SAIFI-S*
		Average # of momentary interruptions per delivery point	*T-SAIFI-M*
		Average minutes that power to a delivery point is interrupted	*T-SAIDI*
		System unavailability (%)	*% of system not available for use*
		Unsupplied energy (minutes.)	*Unsupplied MW-minutes/Peak MW*
	Asset Management	In-service additions as % of OEB-approved plan	*$ ISA as percentage of Planned $ Amounts*
		Capital Expenditures as % of Budget	*$ Capital Expenditures as % of Budgeted $ Capital Expenditures*
	Cost Control	OM&A and Capital Expenditures/Gross fixed asset value	*OM&A and Capital Expenditures/ Gross fixed assets*
		Sustainment capital /Gross fixed asset value	*Sustainment Capital Expenditures/ Gross fixed assets*
		OM&A/Gross fixed asset value	*OM&A/ Gross fixed assets*
Policy Response	Renewables	% of new connection impact assessments completed on time	*Total assessments completed within expected time/Total connections requested*
	Regulatory Compliance	NERC & NPCC Standards Compliance – High impact issues	*# of high impact compliance violations as defined by NERC/NPCC*

Witness: Michael Vels

		NERC & NPCC Standards Compliance – Medium/low impact issues	*# of medium/low impact compliance violations as defined by NERC/NPCC*
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met	*Total deliverables met/Total deliverables expected*
Financial Performance	**Leverage**	Debt to Equity Ratio	*Debt (including Short &Long Term)/Equity*
	Liquidity	Current Ratio	*Current Assets/Current Liabilities*
	Profitability	Return on Equity (deemed)	*Included in rates*
		Return on Equity (achieved)	*Actual return on equity*

Table 2: Tier 2 and Tier 3 Metrics

Performance Categories	Scorecard Metric	Preliminary Tier 2 Metrics	Preliminary Tier 3 Metrics
Service Quality	% Satisfaction with Outage Planning Procedures	% of outages cancelled Planned outages per Delivery Point	
Customer Satisfaction	Overall % satisfied in customer survey		Customer satisfaction with Price (%) Customer Satisfaction with Relationship (%) Product Quality / Reliability Satisfaction (%) Customer Service
		OGCC Transmission Customer Satisfaction (%)	
Safety	Recordable Incidents per 200,000 hours	Recordable Motor Vehicle Accidents (#/1,000,000 km driven)	
System Reliability	T-SAIFI	Interruption frequency for multi-circuit delivery points	Frequency of Momentary Delivery Point Interruptions (MC only) Frequency of Sustained Delivery Point Interruptions (MC only)
		Interruption frequency for single-circuit delivery points	Frequency of Momentary Delivery Point Interruptions (SC only) Frequency of Sustained Delivery Point Interruptions (SC only)
	T-SAIDI	Interruption minutes for multi-circuit delivery points Interruption minutes per single circuit delivery point	
	System Unavailability	Lines Unavailability Stations Unavailability	% of Forced outages caused by equipment type

Witness: Michael Vels

Asset Management	**In-service Additions as % of OEB-approved plan**	% of budgeted work completed on or ahead of schedule	Km of line refurbished versus plan Number of transformers replaced versus plan Number of breakers replaced versus plan
	Capital Expenditures as % of budget	ECS Capital Expenditures/Project Management FTE Engineering Costs/ECS Capital $ ECS CapEx/Construction FTE	
Performance Categories	Scorecard Metric	Preliminary Tier 2 Metrics	Preliminary Tier 3 Metrics
Cost Control	**Total Capital and OM&A/Gross Fixed Assets**	Supply Chain Value Realization % (Ratio of supply chain savings to procurement operations cost)	Sum of discounts and savings from strategic sourcing ($) Sum of Costs of procurement operations ($)
		Facilities & Real Estate value realization (Ratio of facility savings and revenues to real estate operations cost)	Sum of revenues and savings from real estate initiatives ($) Sum of costs of real estate operations ($)
		Overhead as % of net Capital Expenditures Administrative Costs as % of OM&A & Capital Expenditures	Fleet utilization (%)
	Sustainment Capital/Gross Fixed Assets	Actual costs versus estimated costs for completed capital projects (%)	Transmission Wood Structure Condition Assessment ($/pole) Transmission Wood Structure Replacement ($/structure) Transmission Brush Control Cost per Hectares ($/hectare) Transmission Line Clearing Cost per Km ($/Km) Cost per 115kV Tower Coated ($/tower) Cost per 230kV Tower Coated ($/tower) Cost per Transmission Cable Locate ($/locate, network operating only)
	OM&A/Gross Fixed Asset Values	Lines RCE Stations RCE	Ratio of unplanned work to planned work

Witness: Michael Vels

AMPCO INTERROGATORY #47

Reference:

Interrogatory:

a) With respect to corrective and preventive maintenance categories, please discuss Hydro One's priority levels for resolution.

b) Please provide the number of work requests for each of the years 2015 to 2018.

Response:

a) Hydro One's prioritization of preventive, planned corrective and unplanned corrective maintenance is based on a combination of impact to public safety, system reliability and regulatory requirements (such as FERC, NERC and NPCC).

b) The number of work requests for preventive and corrective for each of the years 2015-2018 are listed in the table below. The scope of each work request can vary significantly. Hence the numeric quantity of work requests listed below is not a good representation of the labor hour, cost or system impact.

Number of Work Request	2015	2016	2017	2018
Protection	2,630	2,443	2,316	2,889
Control	506	470	397	396
Power System Telecom	2,902	2,171	2,280	2,593
Overhead Lines	1,867	2,974	3,114	2,822
Underground Cables	857	788	705	714
Transformer	6,219	5,940	6,095	6,658
Breaker	6,782	6,439	5,881	5,046
Switches	1,976	1,867	1,886	1,789
Batteries	4,169	3,790	3,835	4,028
Total Work Request	**27,908**	**26,882**	**26,509**	**26,935**

Witness: Donna Jablonsky

2019-2024

Transmission Business Plan

December 14, 2018

<u>Transmission System Plan</u>

The following sections within the Transmission System Plan are direct excerpts from the 2019-2024 Consolidated Business Plan. For completeness, they have been included to provide a seamless and consistent review of the 2019-2024 Transmission Business Plan.

As part of Hydro One's 2019 Revenue Cap IR application and the upcoming 2020 to 2022 Transmission Rates Application, Hydro One is developing a new five-year Transmission System Plan in accordance with the OEB's revised filing requirements under the RRF, which sets out Hydro One's anticipated capital plans for 2020 through 2024. Since capital expenditures are tied to Maintenance and Operations costs, the Transmission System Plan is based on certain assumptions related to the level of OM&A investment during the planning period.

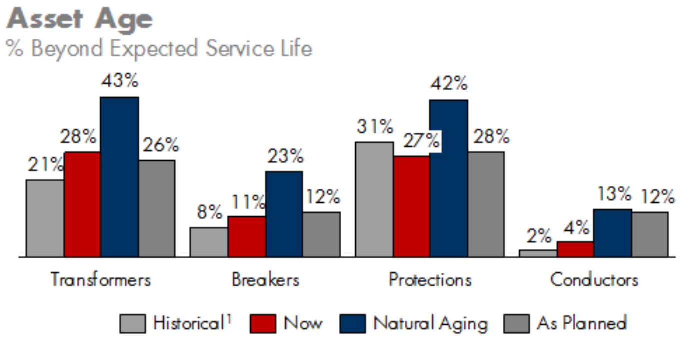
Hydro One's multi-circuit reliability performance is forecast to be Q2 by year end 2018 as compared to its Canadian Electrical Association (CEA) peers. This reliability performance is targeting to improve to Q1 performance by the end of the period.

The transmission customer satisfaction survey results indicate an improving trend, with a 2017 overall satisfaction rating of 85% and a 2018 overall satisfaction rating of 90%. Hydro One still faces challenges in the years ahead to address the needs of an aging transmission system, while maintaining and continuously improving in those areas valued most by its customers and stakeholders, including safety, reliability, outage restoration and power quality.

Hydro One's Transmission System Plan continues to strike a careful balance between: (i) asset related needs of the system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability and reliability risk; (iii) regional infrastructure needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) effect on customer rates.

Hydro One assesses and tests the condition of critical assets; the company continually improves this process through the assessment of asset performance (including failure investigations), improving data governance processes, industry engagement and input from third party experts. Stations and lines risk assessments are informed by the following: oil analysis, maintenance history, loading, ongoing inspection and monitoring information, reliability performance, age, obsolescence, remaining strength, ductility and net present value analysis.

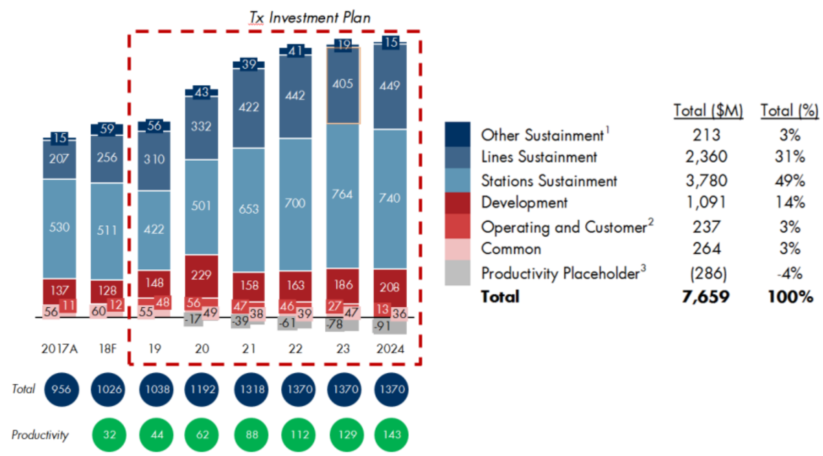
Based on Hydro One's assessment of its transmission system, a significant portion of the assets are reaching the end of their expected service life (ESL) and have deteriorated to the point where investment is required to maintain customer reliability and meet safety and environmental sustainability requirements. Through natural aging, it is forecast that 43% of transformers, 23% of breakers, 42% of protection systems, and 13% of conductors will reach their ESL over the next six years, as shown in the figure following. This evolving age profile is largely due to the significant system development in the 1950s and 1960s; these assets now require replacement.



[1]Historical as per Transmission Rate Application EB-2012-0031 filed May 28, 201

Transmission Capital

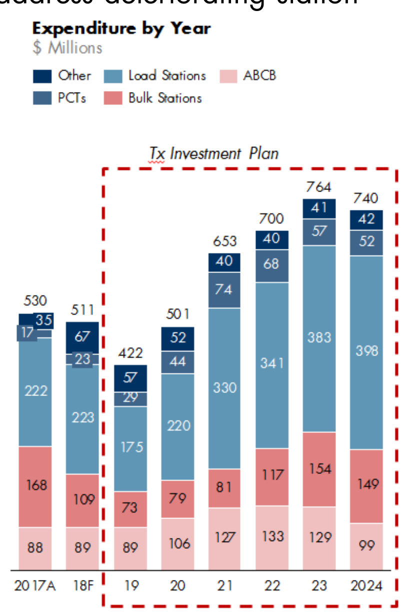
Over the planning period, Hydro one plans to spend approximately \$7.7 billion in capital representing an annual growth of 5.7% over six years to improve transmission reliability performance, address customer needs and preferences, and mitigate asset and operational risks by delivering the capital work summarized described below. This Plan includes \$577 million of capital productivity improvements through information technology, procurement, and process efficiency in executing the work to achieve required results.



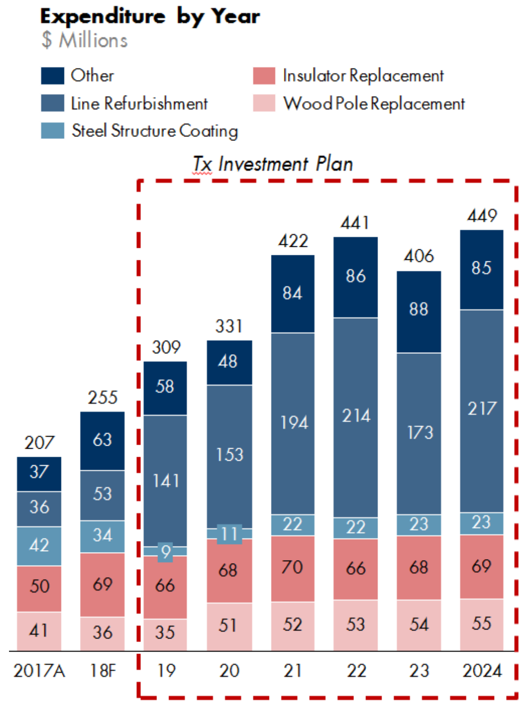
Hydro One's proposed System Plan reflects the need for continued investment in stations sustainment; approximately \$3.8 billion (49%) has been included to address deteriorating station assets, including transformers, circuit breakers, and protection, control and telecom equipment. These replacements are expected to manage the fleet aging of major station assets during the Plan:

Assets that are Beyond Their Expected Service Life (ESL)

	Current State	Natural Aging over 6 Years	Impact of Plan
Transformers (Fleet=715 units)	28%	43%	26%
Breakers (Fleet=4,565 units)	11%	23%	12%
Protection, Control, Telecom (Fleet=12,108 units)	27%	42%	28%



Key renewal investments include the replacement of 95 air-blast circuit breakers (ABCBs) at a cost of $683 million. These older breakers are about ten (10) times more expensive to maintain and about four (4) times less reliable than their newer SF6 circuit breakers. Capital investment is also required to improve transmission station site facilities and meet new security requirements at a cost of $213 million. The station sustainment capital expenditures and program highlights over the Plan are summarized below:



- Replace 117 poor and deteriorated condition transformers at 54 transformers stations while eliminating 22 non-standard transformers;
- Replace 95 (68% of remaining ABCBs) obsolete and poor performing ABCBs and their associated high pressure air systems located at bulk electrical stations that are key for the reliable operation of the transmission system;
- Replace 2,638 obsolete, non-standard and poor performing protection devices; and
- Address new regulatory cyber security and physical security requirements at 53 stations.

The Transmission System Plan includes an increased emphasis on lines sustainment related investments at a cost of $2,360 million to refurbish and replace end of life transmission lines, insulators, and wood poles, and extending the useful life of steel structures through tower coating, but at a reduced pacing consistent with OEB direction in the 2017/2018 rate application.

As a result of natural aging, approximately 13% (~3,760 circuit-km) of transmission lines would be at their 90 year expected service life at the end of the planning period with no planned replacements. The line refurbishment program is informed by detailed condition assessments, which are conducted for lines exceeding 50 years. While the planned rate of refurbishment does not keep up with lines demographics, the risk is managed by prioritizing line refurbishment investments based on detailed asset condition assessment. The pace at which a transmission line deteriorates varies depending on location, environmental and system conditions.

The lines sustainment capital expenditures and program highlights are summarized below:

- Replace 1,830 circuit-km of end-of-life conductors on 71 circuits;
- Replace defective insulators on 21,450 critical circuit structures;
- Replace 4,650 (11%) end-of-life wood poles; and
- Tower coat 2,480 (10%) steel structures to extend their useful life.

The Transmission System Plan also includes $1.1 billion of development capital to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with large industrial customers, distributors and the Independent Electricity System Operator (IESO). This will result in the following system additions:

- Six new transformer stations, 14 customer-owned stations, and 470 new or upgraded transmission line circuit-km; and
- Major projects including the development work for the North-West Bulk Transmission Expansion, new transmission switching and lines facilities required to support the 1300+ MW load growth in the Leamington Area, transformation and lines at Milton Switching Station, and upgrades/expansion in Barrie and Toronto areas.

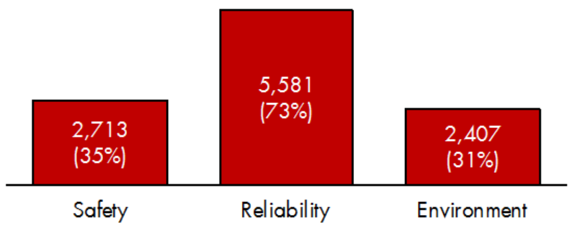
Some of the large Development projects have a high level of external uncertainty and projects such as the East-West Tie line construction have been excluded from the plan based on this uncertainty. The Niagara Reinforcement project, which had been stalled for a number of years, has resumed and is expected to be completed by mid-2019.

The new Integrated System Operating Centre (ISOC) will be constructed during this period in the City of Orillia to satisfy all safety-related and emergency preparedness requirements for both physical and cyber security. This investment is essential to maintaining adequate redundancy for operation of the Bulk Electric System and the Telecom Communication Network as required under North American Electric Reliability Corporation (NERC) EOP-008-2 "Loss of Control Centre Functionality" and Chapter 5, Section 11 of the IESO Market Rules.

In developing the Transmission System Plan, Hydro One considered the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital work efficiently and the ability to secure planned outage time to minimize impacts on customers and other stakeholders. Hydro One expects greater outage scheduling constraints in the future that will make work more difficult to complete.

Safety, environment, and reliability risk mitigation are at the core of the Transmission System Plan. Hydro One strives to be an industry leader in safety and environment for its employees, contractors, and customers and to achieve and maintain "World Class" safety performance. This plan will maintain and improve reliability for customers and incorporates their input and priorities. Each investment is scored for safety, environment, and reliability risk mitigation on a clear and consistent scale. As well, each investment has the potential to address more than one risk factor. Reliability is a focus of this plan with $5.6 billion (73%) of the planned capital expenditures to mitigate reliability risk through the replacement of end of life assets or refurbishment, or system enhancement. $2.7 billion (35%) of planned capital expenditures will mitigate safety risk by replacing deteriorated assets in publicly accessible areas or through the replacement of equipment with known risks to employees. $2.4 billion (31%) is required to mitigate environmental risks, including the installation or refurbishment of oil spill containment facilities and the elimination of PCBs from the system by replacing contaminated equipment with >50ppm to comply with Federal Environmental legislation by 2025. These capital expenditures and the associated risk being mitigated are shown in the figure below.

Risk Driven Spend
$ millions 2019-2024, % of Transmission Capital spend



Hydro One is sensitive to the rate impacts of the investment plan on its customers as well as LDC's end-user customers, and has taken steps to ensure that its approach to investment is, and continues to be, in aligned with principles of the OEB's RRF by:

- ensuring that the Transmission System Plan reflects the consideration of customer needs and preferences identified in the customer engagement process and is consistent with the feedback obtained from various other customer consultations undertaken by the company including consultations with distribution customers;
- identifying specific opportunities (e.g. steel tower coating) where Hydro One can extend the useful life of its assets and mitigate higher capital spending requirements for asset replacements in the future;
- actively driving cost reductions and improved productivity savings to help offset customer rate impacts of the proposed investment plan;
- working with customers, transmitters, distributors and key stakeholders to ensure regional infrastructure issues and requirements are integrated; and
- implementing an improved performance management system to provide greater accountability for performance outcomes.

Hydro One's capital expenditure forecast is $1,026 million for 2019 and increasing to $1,370 million in 2024, representing an average annual increase of 5.7% over the planning period. The table below summarizes the capital investment plan.

Summary of Transmission Capital Plan

$mm	2017A	2018F	2019	2020	2021	2022	2023	2024
Stations Sustainment	530	511	422	501	653	700	764	740
Lines Sustainment	207	256	310	332	422	442	405	449
Other Sustainment	15	59	56	43	39	41	19	15
Development	137	128	148	229	158	163	186	208
Operating and Customer	11	12	48	56	47	46	27	13
Common	56	60	55	49	38	39	47	36
Progressive Placeholder	0	0	0	(17)	(39)	(61)	(78)	(91)
Total	**$956**	**$1026**	**$1038**	**$1192**	**$1318**	**$1370**	**$1370**	**$1370**

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Insulator Replacements
Targeted Start Date: Ongoing Program
Targeted In-Service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address polymer insulators, defective porcelain insulators, and other insulator defects in the system, by replacing insulators with the highest risk of failure. Insulator failure can result in public safety concerns and decreased system reliability. Not proceeding with this investment will negatively impact system reliability, causing an increased number of customer interruptions, and more importantly a public safety risk.

Investment Summary:
Hydro One Transmission currently owns and manages about 420,000 insulator strings. Insulators are used to support the current carrying conductors and provide electric isolation to the supporting steel or wood structures. There are three main types of string insulators used on the transmission system: porcelain, glass and polymer. Quality porcelain and glass insulators normally have a life expectancy similar to that of conductors and do not require replacement until the line is completely refurbished. However, polymer and some porcelain and glass insulators require replacement before the conductor reaches end of life due to manufacturing defects, lightning strikes and vandalism.

Insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982 suffer from a phenomena known as cement expansion or cement growth. The purpose of the cement is to bond the pin to the porcelain. Excessive cement expansion of these insulators would create cracks in the cement and porcelain shell resulting in two possible failure modes:

1. Mechanical Failure causing a conductor drop; and
2. Electrical Failure where the cracked porcelain reduces insulating properties.

As a result, some of these insulators will fail prematurely. Factors such as mechanical load and environmental conditions may also influence the cause premature failure. However cracks in the cement and porcelain shell are not always visible or detectable, which along with the number of insulators in the system, make it difficult to predict which insulators will fail. For example, Hydro One recently experienced an insulator failure on its V76R circuit. In March 2015, the centre phase insulator on V76R failed causing the conductor to fall to the ground in a commercial parking lot in Etobicoke. This type of failure represents a significant public safety risk. As a result, in 2016 Hydro One Transmission implemented an insulator replacement strategy.

There are approximately 34,000 structures with defective COB or CP insulators and roughly 15,000 of these structures have been identified as high risk. High risk structures include structures at road crossings, water and rail crossings and structures near urban areas, golf courses, educational and health care facilities. In 2016, a province wide replacement program for defective COB and CP insulators began. COB and CP insulators on high risk structures will be replaced over the next five years.

The proposed plan will be to replace approximately 4,030 circuit structures and 3,880 circuit structures in 2017 and 2018 respectively.

Alternatives:
Two alternatives were considered:
Alternative 1: Continue program at historical rate (Status Quo); or
Alternative 2: Replacement of the assets.

Alternative 1 was considered and rejected due to the public safety risk and condition of the assets. Alternative 2 is the preferred alternative as it addresses the asset condition, reduces the public safety concern and maintains reliability.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
To reduce public safety risks associated with insulator failures and maintain reliability.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	72.6	69.8	142.4
Operations, Maintenance & Administration and Removals	(8.7)	(8.4)	(17.1)
Gross Investment Cost	**63.9**	**61.4**	**125.3**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**63.9**	**61.4**	**125.3**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

Table 12: Insulator Portfolio Replacement

Insulator Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
# of circuit structures	210	433	233	155	2100	4030	3880
% of Fleet	0.15%	0.3%	0.2%	0.1%	1.4%	2.7%	2.6%

3.5 Transmission Underground Cables

3.5.1 Asset Overview

Hydro One's transmission system consists of approximately 270 km of underground cables that supply city centres in Toronto, Ottawa and Hamilton with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. Transmission underground cables are typically extensions to, or links between, portions of the overhead transmission system operating at 230 kV and 115 kV. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or with each phase conductor self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components all of which need to integrate and function properly in order to deliver power with the reliability that is demanded.

There are three different types of high voltage underground cables in use on the transmission system: Low Pressure Oil Filled ("LPOF") cables, High Pressure Oil Filled Pipe-Type ("HPOF") cables, and Extruded Cross Linked Polyethylene ("XLPE") cables.

Figures 43A through 43C illustrate the three types of underground cables used in Hydro One's transmission system.

List of Material Capital Investments (Exhibit B-1-1 TSP Section 3.3.6.1)

Table 5 - System Access - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SA-01	Connect New IAMGOLD Mine	24.9	0.0	0.0	0.0	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	29.9	0.0	0.0	0.0	0.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	8.0	17.7	6.0	0.0	0.0
SA-04	Connect Metrolinx Traction Substations	6.5	7.9	7.1	1.0	0.0
SA-05	Future Transmission Load Connection Plans	0.0	5.0	24.9	24.9	0.0
SA-06	Protection and Control Modifications for Distributed Generation	3.8	3.1	2.7	2.8	2.8
SA-07	Secondary Land Use Transmission Asset Modifications	55.1	15.0	13.9	15.6	3.9
	System Access Projects & Programs Less Than $3M	**27.6**	**9.4**	**8.5**	**7.8**	**9.2**
Total Gross System Access Capital ($M)		**155.7**	**58.1**	**63.0**	**52.0**	**15.8**
Less Capital Contributions ($M)		*-130.9*	*-46.7*	*-51.3*	*-39.3*	*-11.7*
Total Net System Access Capital ($M)		**24.8**	**11.3**	**11.7**	**12.7**	**4.1**

Table 6 - System Renewal - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SR-01	Air Blast Circuit Breaker Replacement Projects	107.5	128.4	133.5	129.2	98.7
SR-02	Station Reinvestment Projects	107.0	125.4	120.6	87.9	53.9
SR-03	Bulk Station Transformer Replacement Projects	33.2	51.8	72.5	131.5	113.8
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	17.5	32.4	41.4	34.6	49.3
SR-05	Load Station Transformer Replacement Projects	91.2	132.3	129.4	178.5	200.0
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	19.2	30.8	47.5	58.4	77.0
SR-07	Protection and Automation Replacement Projects	6.7	8.6	12.7	12.2	21.7
SR-08	John Transformer Station Reinvestment Project	3.5	17.9	25.6	24.0	20.9
SR-09	Transmission Station Demand and Spares and Targeted Assets	44.2	36.4	37.0	37.7	38.3
SR-10	Transformer Protection Replacement	3.8	0.0	0.0	0.0	0.0
SR-11	Legacy SONET System Replacement	4.1	26.0	27.6	28.1	28.1
SR-12	Telecom Performance Improvements	0.0	0.9	5.5	3.7	0.0
SR-13	ADSS Fibre Optic Cable Replacements	7.0	7.1	1.0	0.0	0.0
SR-14	Mobile Radio System Replacement	2.9	6.2	6.1	4.0	0.0
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	2.8	8.5	2.6	1.5
SR-16	NERC CIP-014 Physical Security Implementation	18.0	18.0	18.0	0.0	0.0
SR-17	NERC CIP Transient Cyber Asset Project	3.5	0.0	0.0	0.0	0.0
SR-18	PSIT Cyber Equipment Replacement	1.0	5.0	7.7	7.0	3.4
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	81.8	122.1	94.5	51.0	75.9
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	62.2	63.4	111.7	117.8	137.7
SR-21	Wood Pole Structure Replacements	51.0	52.0	53.0	54.1	55.2
SR-22	Steel Structure Coating Program	11.4	21.8	22.3	22.7	23.2
SR-23	Tower Foundation Assess/Clean/Coat Program	11.8	22.3	22.8	23.3	23.7
SR-24	Transmission Line Shieldwire Replacement	12.3	12.6	12.8	13.1	13.4
SR-25	Transmission Line Insulator Replacement	68.3	69.7	66.3	67.6	68.9
SR-26	Transmission Line Emergency Restoration	9.6	9.8	10.0	10.2	10.4
SR-27	C5E/C7E Underground Cable Replacement	2.1	29.8	30.9	32.2	29.2
SR-28	OPGW Infrastructure Projects	5.3	7.5	2.2	6.2	9.7
SR-29	Physical Security ISL Application Replacement	5.0	1.1	0.0	0.0	0.0
System Renewal Projects & Programs Less Than $3M		**77.8**	**67.3**	**60.1**	**44.1**	**41.1**
Total Gross System Renewal Capital ($M)		**869.1**	**1109.2**	**1181.1**	**1181.5**	**1194.9**
Less Capital Contributions ($M)		*-3.8*	*-6.1*	*-8.3*	*-4.1*	*-1.1*
Total Net System Renewal Capital ($M)		**865.2**	**1103.1**	**1172.8**	**1177.4**	**1193.8**

List of Material Capital Investments (Exhibit B-1-1 TSP Section 3.3.6.1)

Table 7 - System Service - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SS-01	Lennox TS: Install 500kV Shunt Reactors	32.3	0.0	0.0	0.0	0.0
SS-02	Wataynikaneyap Line to Pickle Lake Connection	24.9	1.5	0.0	0.0	0.0
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	3.0	10.0	4.0	0.0	0.0
SS-04	East-West Tie Connection	46.3	38.8	22.6	0.0	0.0
SS-05	St. Lawrence TS: Phase Shifter Upgrade	9.0	18.0	9.0	0.0	0.0
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	5.0	10.0	8.4	0.0	0.0
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	2.0	3.0	69.4	119.1
SS-08	Northwest Bulk Transmission Line	8.0	12.9	8.9	0.0	0.0
SS-09	Barrie Area Transmission Upgrade	38.1	28.2	8.5	0.0	0.0
SS-10	Kapuskasing Area Transmission Reinforcement	6.7	3.8	0.0	0.0	0.0
SS-11	South Nepean Transmission Reinforcement	27.5	10.5	0.0	0.0	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	10.0	13.1	6.1	0.0	0.0
SS-13	Leamington Area Transmission Reinforcement	4.9	9.7	59.1	63.8	63.8
SS-14	Southwest GTA Transmission Reinforcement	10.3	7.8	6.9	3.9	2.0
SS-15	Future Transmission Regional Plans	0.0	0.0	10.5	19.6	0.0
SS-16	Customer Power Quality Program	3.3	3.4	3.4	3.4	3.5
System Service Projects & Programs Less Than $3M		**9.1**	**8.2**	**9.9**	**14.0**	**15.9**
Total Gross System Service Capital ($M)		**238.3**	**177.9**	**160.3**	**174.3**	**204.2**
Less Capital Contributions ($M)		*-34.2*	*-29.7*	*-8.5*	*0.0*	*0.0*
Total Net System Service Capital ($M)		**204.1**	**148.2**	**151.8**	**174.3**	**204.2**

Table 8 - General Plant - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
GP-01	Integrated System Operations Centre - New Facility Development	32.4	12.7	0.0	0.0	0.0
GP-02	Grid Control Network Sustainment	8.0	6.1	6.3	6.5	6.6
GP-03	Network Management System Capital Sustainment	0.0	7.8	22.4	8.2	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	1.9	3.2	1.1	0.0
GP-05	Transmission Non-Operational Data Management System	5.2	5.3	5.4	5.5	1.1
GP-06	Operating Common IT Infrastructure	0.8	2.0	3.7	3.3	2.2
GP-07	Hardware/Software Refresh and Maintenance	2.0	2.0	1.9	1.9	5.8
GP-08	Corporate Services Transformation - HR / Payroll	5.0	1.5	0.0	0.0	0.0
GP-09	Corporate Services Transformation - Finance	1.0	3.0	5.0	6.5	5.0
GP-10	Facility Accommodation & Improvements Service Centres & Admin	8.1	4.9	8.2	16.4	4.3
GP-11	Transmission Facilities & Site Improvements	9.4	9.5	9.6	9.7	9.9
GP-12	Transport & Work Equipment	13.2	13.2	13.3	13.3	13.3
General Plant Projects & Programs Less Than $3M		**30.2**	**24.3**	**15.8**	**11.1**	**10.7**
Total Gross System Service Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**
Total Net General Plant Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**

ISD List of Material Capital Investments
(Net $ Millions)

Table 5 - System Access - Material Capital Investments Proposed

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SA-01	Connect New IAMGOLD Mine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4
SA-04	Connect Metrolinx Traction Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
SA-05	Future Transmission Load Connection Plans	0.0	0.0	0.0	8.0	0.0	0.0	0.0	0.0	0.0
SA-06	Protection and Control Modifications for Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SA-07	Secondary Land Use Transmission Asset Modifications	0.1	0.4	1.2	0.5	(0.7)	(1.0)	4.3	5.0	2.9

Table 6 - System Renewal - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SR-01	Air Blast Circuit Breaker Replacement Projects	66.8	61.0	89.2	58.9	88.0	79.6	79.0	61.6	88.5
SR-02	Station Reinvestment Projects	6.7	45.7	37.8	38.6	67.6	64.4	70.0	63.1	104.8
SR-03	Bulk Station Transformer Replacement Projects	(0.2)	0.0	0.2	0.2	1.2	1.3	0.9	7.8	9.9
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	0.0	0.0	0.0	0.0	0.5	0.2	1.8	3.3	2.4
SR-05	Load Station Transformer Replacement Projects	10.1	5.0	8.8	0.9	12.2	12.0	15.0	26.8	40.3
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	0.3	1.9	3.7	9.7	1.6	1.7	16.0	15.7	11.7
SR-07	Protection and Automation Replacement Projects	0.0	0.0	0.0	0.0	0.2	0.2	0.4	2.5	1.9
SR-08	John Transformer Station Reinvestment Project	0.1	14.0	0.0	5.9	0.0	0.1	0.0	0.0	0.2
SR-09	Transmission Station Demand and Spares and Targeted Assets	27.0	11.1	24.2	16.4	18.5	23.6	49.6	37.1	49.7
SR-10	Transformer Protection Replacement	0.1	0.0	1.5	0.0	3.4	3.1	3.1	4.1	3.0
SR-11	Legacy SONET System Replacement	0.0	0.0	0.0	0.0	1.2	1.1	3.3	2.4	1.5
SR-12	Telecom Performance Improvements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SR-13	ADSS Fibre Optic Cable Replacements	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.4	0.5
SR-14	Mobile Radio System Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SR-16	NERC CIP-014 Physical Security Implementation	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	17.9
SR-17	NERC CIP Transient Cyber Asset Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5
SR-18	PSIT Cyber Equipment Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	5.4
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	0.2	0.0	2.1	0.0	8.1	7.8	42.7	47.0	104.6
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	0.0	0.0	0.0	0.0	0.4	0.4	0.3	3.6	12.8
SR-21	Wood Pole Structure Replacements	20.8	13.8	43.8	14.1	42.7	40.3	35.3	34.9	34.8
SR-22	Steel Structure Coating Program	5.1	8.8	2.3	10.3	42.1	39.0	37.7	27.0	9.3
SR-23	Tower Foundation Assess/Clean/Coat Program	1.4	4.2	1.6	4.3	7.0	5.9	4.7	7.7	13.1
SR-24	Transmission Line Shieldwire Replacement	4.8	4.3	1.4	4.4	5.4	4.8	9.3	10.2	9.9
SR-25	Transmission Line Insulator Replacement	2.9	3.6	29.5	3.7	48.9	53.1	65.5	64.8	66.2
SR-26	Transmission Line Emergency Restoration	8.7	10.9	13.8	11.1	8.3	7.6	9.7	9.0	9.4
SR-27	C5E/C7E Underground Cable Replacement	0.0	0.0	0.0	0.0	0.5	0.3	0.5	0.6	3.2
SR-28	OPGW Infrastructure Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	1.2
SR-29	Physical Security ISL Application Replacement	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.0	7.8

ISD List of Material Capital Investments
(Net $ Millions)

Table 7 - System Service - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SS-01	Lennox TS: Install 500kV Shunt Reactors	0.0	0.0	0.0	0.0	0.3	0.2	1.1	2.0	13.2
SS-02	Wataynikaneyap Line to Pickle Lake Connection	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	3.2
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS-04	East-West Tie Connection	0.1	0.0	1.7	0.0	4.4	4.3	8.6	10.8	31.5
SS-05	St. Lawrence TS: Phase Shifter Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	0.0	0.0	0.1	0.0	0.1	0.1	0.0	0.3	0.5
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS-08	Northwest Bulk Transmission Line	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	5.0
SS-09	Barrie Area Transmission Upgrade	0.0	0.0	0.4	0.0	1.8	2.0	1.8	6.5	2.6
SS-10	Kapuskasing Area Transmission Reinforcement	0.0	0.0	0.1	0.0	0.7	0.7	1.7	1.5	17.5
SS-11	South Nepean Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.8	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.0	1.0
SS-13	Leamington Area Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
SS-14	Southwest GTA Transmission Reinforcement	0.0	0.0	0.2	0.0	0.1	0.1	0.3	1.2	1.9
SS-15	Future Transmission Regional Plans	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0
SS-16	Customer Power Quality Program	0.0	0.0	0.0	0.0	0.0	0.0	0.4	3.3	3.3

Table 8 - General Plant - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
GP-01	Integrated System Operations Centre - New Facility Development	0.2	0.0	4.0	0.0	0.8	1.0	0.6	23.0	28.8
GP-02	Grid Control Network Sustainment	0.5	2.0	3.4	3.0	2.9	2.4	3.6	6.4	7.2
GP-03	Network Management System Capital Sustainment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-05	Transmission Non-Operational Data Management System	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-06	Operating Common IT Infrastructure	0.0	0.0	0.0	1.6	0.0	0.9	0.0	1.0	1.7
GP-07	Hardware/Software Refresh and Maintenance	5.7	4.7	8.0	4.4	6.2	6.5	4.0	7.3	3.7
GP-08	Corporate Services Transformation - HR / Payroll	0.0	0.0	0.0	0.0	0.0	0.0	0.4	2.0	0.5
GP-09	Corporate Services Transformation - Finance	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.5	0.2
GP-10	Facility Accommodation & Improvements Service Centres & Admin	0.1	0.8	6.4	0.8	5.3	7.9	4.9	19.3	7.2
GP-11	Transmission Facilities & Site Improvements	0.0	0.0	6.2	0.0	10.6	12.0	16.4	10.0	12.0
GP-12	Transport & Work Equipment	16.7	14.9	20.4	17.1	13.7	14.5	7.2	14.1	13.3

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2017 OR 2018

1. SUSTAINING CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 2)

1.1 Stations

		2017	2018
Air Blast Circuit Breaker Replacement Projects			
S01	Beck #1 SS	5.9	12.0
S02	Beck #2 TS	29.8	14.9
S03	Bruce A TS	13.8	19.7
S04	Bruce B SS	0.9	24.6
S05	Cherrywood TS	1.4	3.8
S06	Lennox TS	26.1	16.9
S07	Richview TS	16.9	13.5
Station Reinvestment Projects			
S08	Beach TS	16.5	15.9
S09	Centralia TS	12.5	6.2
S10	Dryden TS	16.2	0.1
S11	Elgin TS	22.6	17.8
S12	Espanola TS	3.0	0.0
S13	Gage TS	1.2	12.4
S14	Kenilworth TS	5.6	11.2
S15	Nelson TS	10.9	20.2
S16	Palmerston TS	8.8	11.6
S17	Wanstead TS	13.7	14.3
Integrated Station Component Replacement Projects			
S18	Alexander SS	14.4	8.8
S19	Allanburg TS	4.7	1.0
S20	Aylmer TS	3.5	0.0
S21	Barrett Chute SS	9.3	3.9
S22	Birch TS	12.1	13.8
S23	Bronte TS	3.7	17.1
S24	Bridgman TS	0.2	3.3
S25	Buchanan TS	4.2	0.0
S26	Cecil TS	9.6	0.0

		2017	2018
S27	Chenaux TS	7.5	2.1
S28	Crawford TS	4.2	0.0
S29	DeCew Falls SS	4.9	0.0
S30	Dufferin TS	6.5	7.4
S31	Ear Falls TS	10.9	0.0
S32	Frontenac TS	3.8	1.5
S33	Hanmer TS	24.4	11.0
S34	Hawthorne TS	1.6	4.3
S35	Horning TS	14.3	14.9
S36	Leaside TS Bulk	5.9	5.6
S37	Leaside TS 27.6 kV	6.3	6.5
S38	Main TS	5.4	8.4
S39	Manby TS	3.1	1.8
S40	Martindale TS	18.6	18.6
S41	Minden TS	4.2	7.0
S42	Mohawk TS	4.6	4.7
S43	N.R.C. TS	7.1	0.7
S44	Pine Portage SS	1.9	5.9
S45	Richview TS	7.3	0.0
S46	Sheppard TS	9.8	9.3
S47	St. Isidore TS	9.1	0.0
S48	Stanley TS	0.5	6.1
S49	Strachan TS	5.1	2.8
S50	Strathroy TS	5.3	0.0
Transmission Station Demand and Spares			
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
Protection, Control and Monitoring			
S54	Transformer Protection Replacement	4.6	4.6
S55	Replace Legacy SONET Systems	2.1	5.3
S56	Physical Security for Critical Stations (non CIP-014)	5.0	5.0
S57	CIP V6 Transient Cyber Assets & Removable Media	2.0	10.0
S58	PSIT Cyber Equipment EOL	5.0	6.0
S59	CIP-014 Physical Security Implementation	6.0	6.0
S60	NERC CIP V6 CAPEX - Low Impact Facilities	5.0	5.0
Transmission Site Facilities			
S61	Transmission Site Facilities	6.7	6.7

1.2 Lines

		2017	2018
Transmission Line Refurbishment Projects			
S62	Line Refurbishment Project - C22J/C24Z/C21J/C23Z	18.5	2.5
S63	Line Refurbishment Project - D2L Dymond x Upper Notch	8.4	0.0
S64	Line Refurbishment Project - C1A/C2A/C3A	1.8	3.5
S65	Line Refurbishment Project - N21W/N22W	4.1	11.9
S66	Line Refurbishment Project - B5G/B6G	4.4	11.4
S67	Line Refurbishment Project - D2L Upper Notch x Martin River	18.3	21.1
S68	Line Refurbishment Project - B3/B4	0.9	6.4
S69	Line Refurbishment Project - A8K/A9K	0.4	6.6
S70	Line Refurbishment Project - A7L/R1LB and 57M1	0.9	20.5
S71	Line Refurbishment Project - K1/K2	0.9	7.4
S72	Line Refurbishment Project - E1C	0.9	12.8
S73	Line Refurbishment Project - D6V/D7V	2.6	5.7
S74	Line Refurbishment Project - D2H/D3H	0.9	12.5
Overhead Lines Component Replacement Programs			
S75	Wood Pole Replacements	35.3	35.3
S76	Steel Structure Coating	42.5	54.4
S77	Steel Structure Foundation Refurbishments	7.8	7.8
S78	Shieldwire Replacements	7.0	7.1
S79	Insulator Replacements	63.9	61.4
S80	Transmission Lines Emergency Restoration	8.7	8.8
Secondary Land Use and Recoverable Projects			
S81	Gordie Howe International Bridge (Recoverable)	12.7	12.5
S82	Manvers – Lafarge Aggregate Pit (Recoverable)	1.0	3.8
Underground Cable Projects			
S83	H7L/H11L Cable Replacement	1.3	21.1

Summary – Sustaining Capital

	2017	2018
Total Sustaining Capital Projects & Programs Listed Above	740.0	785.6
Sustaining Capital Projects & Programs Less than $3M	74.8	87.2
Total Gross Sustaining Capital	**814.8**	**872.8**
Less Capital Contribution	*(38.0)*	*(30.7)*
Total Net Sustaining Capital (per Exhibit B1-3-2)	**776.8**	**842.1**

Witness: Multiple Witnesses

2. DEVELOPMENT CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 3)

		2017	2018
2.1	**Inter-Area Network Transfer Capability**		
D01	Clarington TS: Build new 500/230kV Station	68.6	14.8
D02	Nanticoke TS: Connect HVDC Lake Erie Circuit	5.0	13.0
D03	Merivale TS to Hawthorne TS: 230 kV Conductor Upgrade	2.5	8.0
D04	East-West Tie Expansion: Station Work	3.0	30.0
D05	Milton SS: Station Expansion and Connect 230kV Circuits	2.0	5.0
2.2	**Local Area Supply Adequacy**		
D06	Galt Junction: Install In-Line Switches on M20D/M21D Circuits	3.6	0.1
D07	York Region: Increase Transmission Capability for B82V/B83V Circuits	22.6	0.2
D08	Hawthorne TS: Autotransformer Upgrades	8.0	5.8
D09	Brant TS: Install 115kV Switching Facilities	5.0	6.0
D10	Riverdale Junction to Overbrook TS: Reconfiguration of 115kV Circuits	2.4	4.2
D11	Southwest GTA Transmission Reinforcement	0.9	5.0
D12	Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits	4.0	20.0
2.3	**Load Customer Connection**		
D13	Ear Falls TS to Dryden TS: Upgrade 115kV Circuit E4D	10.0	5.9
D14	Supply to Essex County Transmission Reinforcement	33.0	31.4
D15	Horner TS: Build 230/27.6kV Transformer Station	16.0	13.0
D16	Lisgar TS: Transformer Upgrades	10.3	2.5
D17	Seaton MTS: Rebuild 230 kV Circuit	3.3	3.0
D18	Hanmer TS: Build 230/44kV Transformer Station	9.5	18.5
D19	Runnymede TS: Build 115/27.6kV Transformer Station and Reconductor 115kV Circuits	23.0	17.0
D20	Toyota Woodstock: Upgrade Station	3.0	2.5
D21	Enfield TS: Build 230/44kV Transformer Station	10.0	15.0
D22	TransCanada: Energy East Pipeline Conversion	1.9	10.2
2.4	**Protection and Control for Distributed Generation**		
D23	Protection and Control Modifications for Distributed Generation	6.0	5.5

		2017	2018
2.5	**Risk Mitigation**		
D24	Nanticoke TS: New Station Service Supply	10.0	0.0

Summary – Development	2017	2018
Total Development Projects & Programs Listed Above	**263.6**	**236.6**
Development Projects & Programs Less than $3 M	**27.4**	**33.3**
Total Gross Development Capital (per Exhibit B1-3-3)	**291.0**	**269.9**
Less Capital Contribution	*(94.7)*	*(99.7)*
Total Net Development Capital (per Exhibit B1-3-3)	**196.4**	**170.2**

3. OPERATIONS CAPITAL (EXHIBIT B1, TAB 3, SCHEDULE 4)

3.1 Grid Operations and Control Facilities

		2017	2018
O01	Integrated System Operations Centre - New Facility Development	4.2	10.5

3.2 Operating Infrastructure

		2017	2018
O02	Station Local Control Equipment Sustainment	3.6	3.7
O03	Grid Control Network Sustainment	5.8	3.0

Summary – Operations	2017	2018
Total Operations Projects & Programs Listed Above	13.6	17.2
Operations Projects & Programs Less than $3 M	11.7	13.5
Total Operations Capital (per Exhibit B1-3-4)	**25.4**	**30.8**

4. COMMON CORPORATE CAPITAL AND OTHER COSTS (EXHIBIT B1, TAB 3, SCHEDULES 5-8)

Transmission Allocation of Capital Corporate Costs and Other Costs		**2017**	**2018**
4.1	**Information Technology**		
IT1	Hardware/Software Refresh and Maintenance	5.1	5.1
IT2	MFA Servers and Storage	4.2	2.8
IT3	Work Management and Mobility	5.0	3.0
4.2	**Other**		
CC1	Real Estate Field Facilities Capital	18.4	20.9
CC2	Transport & Work Equipment	20.9	21.8
CC3	Service Equipment	3.2	3.2

Summary - Capital Common Corporate Costs & Other Costs		
Total Capital Common Corporate Costs Projects listed above	56.8	56.8
Capital Common Corporate Costs Projects less than $3 M	20.8	22.3
Transmission Allocation of Capital Common Corporate Costs & Other Costs (per Exhibit B1-3-5)	**77.6**	**79.1**

UNDERTAKING - JT 1.16

Reference:
I-12-AMPCO-023

Undertaking:
To provide the refined cost and schedule metrics that Hydro One uses to track cost schedule and scope, as referred to in AMPCO 23.

Response:
Hydro One is continuously improving the reports it uses to evaluate project performance. Below is a list of metrics used on both a project and portfolio basis.

Project Level Metrics:

- On-time: Project In-Service Date Forecast versus Current Approved
- On-time: Project In-Service Date Forecast versus Original Approved
- On-budget: Gross Project Total Forecast versus Current Approved
- On-budget: Gross Project Total Forecast versus Original Approved

Portfolio Level Metrics:

- In-Service Additions: Annual Forecast versus Budget
- Capital Expenditures: Annual Forecast versus Budget
- Portfolio Risk: Number of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Portfolio Risk: Value of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Project Cost Performance: Number of Projects complete within AACE Estimate Class Range documented in original approval
- Project Cost Performance: Value of Projects complete within AACE Estimate Class Range documented in original approval
- Cost Variance Distribution: Portion of Project Portfolio Delivered On Budget, Over Budget, Under Budget
- Cost Variance Distribution: Standard Deviation of Project Cost Performance represented as a percentage of original Budgets
- Schedule Variance Distribution: Portion of Project Portfolio Delivered On-time, Late, Early
- Schedule Variance Distribution: Standard Deviation of Schedule Variance in Days

Witness: Andrew Spencer

UNDERTAKING - JT 2.19

<u>Reference:</u>
I-12-AMPO-035

<u>Undertaking:</u>
To explain the calculation of the vehicle utilization rate, giving an example.

<u>Response:</u>
The details of how Utilization Rate is calculated are indicated in the table below.

in $ millions, u.o.s.	**2015**	**2016**	**2017**	**2018**	
Operating Cost	133.1	133.2	133.7	135.7	A
Utilization, *in millions of hours*	6.2	6.2	5.8	5.7	B
Utilization Rate	**21.4**	**21.3**	**23.0**	**24.0**	A÷B

UNDERTAKING - JT 1.19

Reference:

Audit 2018-19

Undertaking:

To confirm the forecast completion date for the audit entitled "work program - cost management and reporting."

Response:

The forecasted completion date for the actions associated with the Work Program – Cost Management and Reporting audit is September 30, 2019.

UNDERTAKING - JT 1.12

Reference:

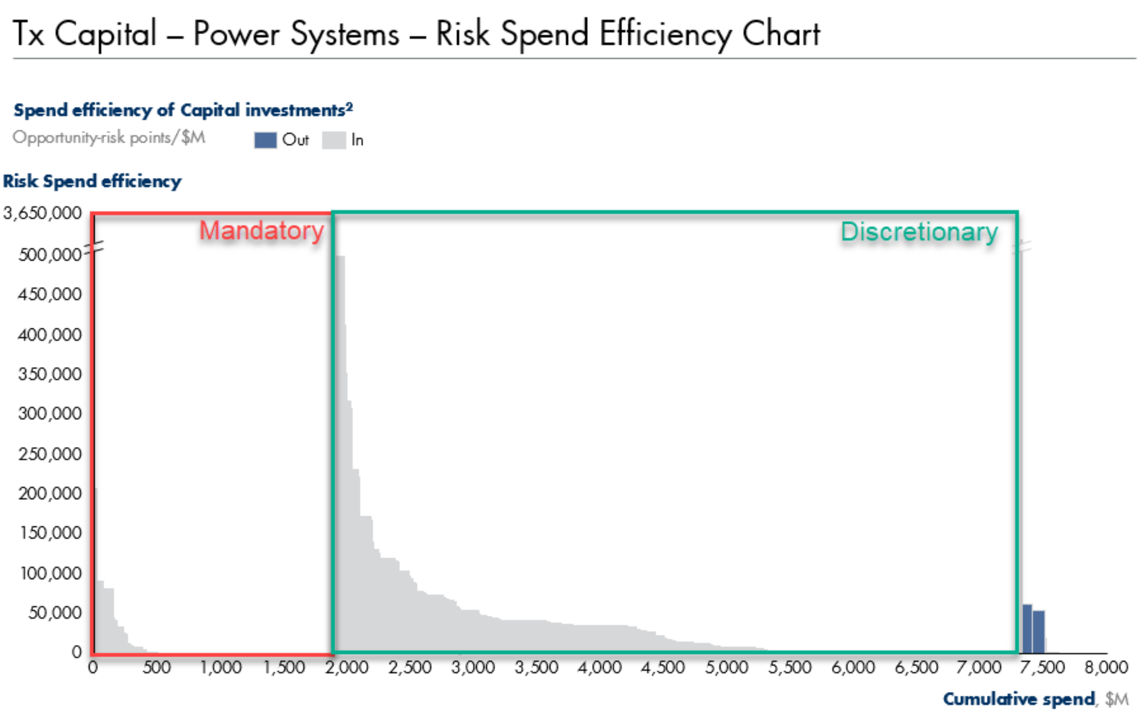
I-07-SEC-032, part a)

Undertaking:

To provide data clarifying costs and risk score (reference SEC IR 32).

Response:

The table below has been structured in a manner consistent with the pre-filed evidence to allow for a meaningful comparison. Investments have been categorized as either mandatory or discretionary, consistent with the criteria described in Exhibit B, Tab 1, Schedule 1, Section 2.1. The graph included in SEC-32, includes mandatory investments, and subsequently discretionary investments, with expenditures planned over the 2019-24 period, as shown below:



1. Includes Power System investments only. Value for other allocations are primarily evaluated on productivity or flagging basis
2. Ranking based on investments flagged as Mandatory followed by Risk Spend Efficiency. For presentation purposes, investments with an efficiency rating greater than 500k points have been set at 500k; those with an efficiency raring of 0 have been set at 10

Mandatory investments meet one of the four mandatory flag criteria outlined in TSP 2.1, page 37 and reproduced below:

Witness: Bruno Jesus

- **Immediate / Short-term Compliance –** Explicit obligation to a regulatory agency (e.g. OEB requires work to be done *within a year* with *immediate risk* of legal breach, or there is a *two to five-year risk* of regulatory or legal breach);
- **Third party requests –** Explicit connection request by a city, county, agency, or customer, with a *one to five-year risk* of breaking the utility obligation to serve;
- **Contractual –** Signed, fixed-sum contracts with third parties for services such as IT support, facility support, etc.; and
- **In-Flight –** Project already under construction.

In some cases, mandatory investments were not re-scored because they were in-flight, or were scored low based on a compliance obligation.

	ISD	**ISD Name**	**2019-2024 Spend ($ M)**	**Total Risk Mitigation**	**Risk Spend Efficiency[1]**
Mandatory[2]	SA-01	Connect New IAMGOLD Mine	10	-	-
	SA-02	Horner TS: Build a Second 230/27.6kV Station	6	-	-
	SA-03	Halton TS: Build a Second 230/27.6kV Station	6	-	-
	SA-04	Connect Metrolinx Traction Substations	11	-	-
	SA-05	Future Transmission Load Connection Plans	19	-	-
	SA-06	Protection and Control Modifications for Distributed Generation	-	879,930	500,000
	SA-07	Secondary Land Use Projects	-	-	-
	SR-01	Air Blast Circuit Breaker Replacement Projects	219	10,897,936	49,845
	SR-02	Station Reinvestment Projects	142	115,142	813
	SR-03	Bulk Station Transformer Replacement Projects	20	251,406	12,274
	SR-05	Load Station Transformer Replacement Projects	51	65,233	1,272
	SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	20	21,795	1,088
	SR-10	Transformer Protection Replacement	7	-	-
	SR-15	Telecom Fibre IRU Agreement Renewals	15	3,190,264	206,982
	SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	49	585,075	11,967
	SR-24	Transmission Line Shieldwire Replacement	74	665,383	8,982
	SR-26	Transmission Line Emergency Restoration	59	1,992,879	33,552

[1] Investments with an efficiency rating of 0 are either in-flight or driven by regulatory compliance, contractual commitments, customer requests or economical efficiencies.
[2] Certain System Renewal investment are included in both the Mandatory and Discretionary categories based on the taxonomies as certain sites are currently in-flight. Refer to TSP 2.1 pages 37-38 for mandatory/discretionary categorization.

	ISD	ISD Name	2019-2024 Spend ($ M)	Total Risk Mitigation	Risk Spend Efficiency[1]
	SS-01	Lennox TS: Install 500kV Shunt Reactors	46	-	-
	SS-02	Wataynikaneyap Power Line to Pickle Lake Connection	30	-	-
	SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	-	-	-
	SS-04	East-West Tie Connection	127	-	-
	SS-05	St. Lawrence TS: Phase Shifter Upgrade	18	-	-
	SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	24	-	-
	SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	194	-	-
	SS-08	Northwest Bulk Transmission Line	35	-	-
	SS-09	Barrie Area Transmission Upgrade	75	-	-
	SS-10	Kapuskasing Area Transmission Reinforcement	28	-	-
	SS-11	South Nepean Transmission Reinforcement	1	-	-
	SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	30	-	-
	SS-13	Leamington Area Transmission Reinforcement	206	-	-
	SS-14	Southwest GTA Transmission Reinforcement	33	-	-
	SS-15	Future Transmission Regional Plans	44	-	-
	SS-16	Customer Power Quality Program	20	-	-
		Less than $3M	296	5,272,230	17,814
Discretionary	GP-02	Grid Control Network Sustainment	41	772,412	18,926
	GP-05	Transmission Non-Operational Data Management System	23	25,420	1,125
	SA-07	Secondary Land Use Projects	7	-	-
	SR-01	Air Blast Circuit Breaker Replacement Projects	464	60,937,116	131,344
	SR-02	Station Reinvestment Projects	458	22,478,975	49,088
	SR-03	Bulk Station Transformer Replacement Projects	392	22,150,917	56,472
	SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	176	65,981,862	374,265
	SR-05	Load Station Transformer Replacement Projects	719	10,637,910	14,799
	SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	225	10,137,180	45,150
	SR-07	Protection and Automation Replacement Projects	64	10,084,973	158,113
	SR-08	John Transformer Station Reinvestment Project	86	1,465,442	17,038
	SR-09	Transmission Station Demand and Spares and Targeted Assets	243	7,269,990	29,886
	SR-11	Legacy SONET System Replacement	115	1,008,208	8,731
	SR-13	ADSS Fibre Optic Cable Replacements	4	484,854	114,499

	ISD	ISD Name	2019-2024 Spend ($ M)	Total Risk Mitigation	Risk Spend Efficiency[1]
	SR-14	Mobile Radio System Replacement	20	201,590	10,170
	SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	481	996,525	2,072
	SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	506	355,060	702
	SR-21	Wood Pole Structure Replacements	300	12,487,336	41,607
	SR-22	Steel Structure Coating Program	111	-	-
	SR-25	Transmission Line Insulator Replacement	407	14,289,148	35,117
	SR-27	C5E/C7E Underground Cable Replacement	127	176,963	1,390
	SR-28	OPGW Infrastructure Projects	32	321,485	10,041
		Less than $3M	402	20,108,484	50,065
Excluded		Less than $3M	360	32,790,878	91,171

As part of Enterprise Engagement and Challenge Sessions, trade-off decisions assess which investments should be promoted or demoted based on the following levers:

- **Risk:** Is Hydro One comfortable with the remaining risk? Are there unfunded investments which mitigate large risks?
- **Flags (non-risk parameters):** Which investments need to be funded for non-risk merits?

The consideration of risk efficiency and risk mitigated per dollar and other considerations supports the making of prudent and data-driven trade-off decisions. Investments that were prioritized out of the plan ("Excluded") have not been included in this application; examples of these candidate investments included power system telecom investments, station reinvestment and component replacements, replacement of wood pole structures in non-publicly accessible locations, and future line refurbishments which are expected to be assessed to be end-of-life at a later date.

SR-09 Transmission Station Demand, Spares and Targeted Assets

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Ongoing Program	**3 Year Test Period Cost ($M):**	117.6
Trigger(s):	Compliance, Strategic, Customer Satisfaction, Corrective Maintenance, Reliability and Environment		
Outcomes:	Compliance with ORTAC and TSC; improve customer satisfaction by carrying out replacements in a timely manner to minimize unplanned customer interruptions; maintain transmission system reliability, safety, and/or power quality; reduce safety risks associated with failing equipment		

A. OVERVIEW

Transmission Station Demand and Spares (the "Program") is a reactive program that is primarily designed to prevent, immediately respond to, or minimize the effects of an emergency situation. The Program involves the procurement of spare transmission station equipment such as transformer operating spares, circuit breakers, instrument transformer, disconnect switches, insulators, power cables, surge arrestors, capacitor banks, reactors, protection, and control and telecom equipment. The Program covers the resources required for emergency replacement of transformers or other minor station equipment that have failed or shown signs of deterioration while in-service and near term deteriorated asset replacements that do not align with station centric projects. It also includes the necessary design, construction and commissioning resources to replace failed station equipment in a timely manner.

Failed or deficient station equipment may cause an impact on the transmission system that varies from being minor to significant. It might pose safety or environmental risks as well as impose generation and/or power flow constraints, affecting regional load flow limits and customer operations. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards administered by the IESO and the Transmission System Code (the "TSC"). The Program ensures that Hydro One continues to

Public Policy Responsiveness	• Ensure Hydro One meets its compliance obligations with respect to power system restoration and reactive response.

C. EXPENDITURE PLAN

Table 2 below presents forecasted costs for the Program, which are established based on based on comparable historical costs and projected future needs.

Table 2 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	45.4	37.5	38.1	38.8	39.5	0.0	199.2
Less Removals	0.0	1.2	1.1	1.1	1.1	1.2	0.0	5.6
Gross Investment Cost	**0.0**	**44.2**	**36.4**	**37.0**	**37.7**	**38.3**	**0.0**	**193.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**44.2**	**36.4**	**37.0**	**37.7**	**38.3**	**0.0**	**193.6**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

Factors driving the costs of this Program are:

- The scope of the replacement work required to address the failure;
- The type, rating and quantity of the assets requiring replacement;
- The historical annual quantity of transformer failures and demand transformer replacements that require spare deployment; and
- The type of transformer requiring spare deployment, as the costs of the operating spare transformers can vary based on transformer specifications such as voltage and capacity.

Controllable costs are being managed and minimized through the standardization of station designs and equipment ratings that result in the reduction of spare inventory for replacement parts, and through the establishment of unit price contracts with vendors.

SR-11 Legacy SONET System Replacement

Start Date:	Q2 2017	**Priority:**	High
In-Service Date:	Q4 2024	**3 Year Test Period Cost ($M):**	57.7
Trigger(s):	System Renewal		
Outcomes:	Maintain reliability of the transmission system operation and maintenance		

A. OVERVIEW

Legacy SONET Systems Replacement (the "Project") involves the replacement of Hydro One's Synchronous Optical Network ("SONET") system with a new packet-based technology. The SONET system is based on SONET technology which is primarily utilized by Protection and Supervisory Control and Data Acquisition ("SCADA") systems. The SONET system, along with the physical infrastructure (fibre or microwave-based) that establishes communication links, are the cornerstones of Protection and Automation systems which support grid reliability as well as protection of costly station and line assets. Additionally, SONET is used for communicating non-operational data, business data, voice and security information, and is used as backhaul communication for the provincial mobile radio system.

SONET system, which primarily includes multiplexer equipment at transmission stations, is approaching its end of life ("EOL").The determination of approaching EOL in this case is made by the facts listed below:

- Large segments of the system are exceeding expected service life ("ESL"), and
- High risk for grid reliability,
- Technological obsolescence as vendors withdraw support (end of vendor support), and;
- Long lead times for planning and execution of asset replacements due to large installed base.

Witness: Donna Jablonsky

E. EXECUTION RISK AND MITIGATION

The main risk to the Project is finding a solution that satisfies Hydro One’s functional and economical requirements. The developmental phase of the Project will find a technology that will fulfill these requirements by the end of 2019 before pursuing implementation.

Witness: Donna Jablonsky

SR-22 Steel Structure Coating Program

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3-year Test Period Cost ($M):**	55.5
Trigger(s):	Cost Avoidance, Preventative Maintenance / System Renewal, Safety, Reliability		
Outcomes:	Extends the life of steel structures by coating them and thus preventing costly future capital investments into complex repairs or structure replacements;		

A. OVERVIEW

Steel Structure Coating Program (the "Program") involves coating transmission line steel structures that are corroding. Coating the steel structure with zinc-based product will provide on-going protection to the underlying carbon steel and preserve the steel structure. Given the condition and the risks associated with steel structure failures, the Program is required to avoid tower failure, negative impacts to reliability and increased costs for tower replacements. Avoiding significant costs in the future through tower coating is the objective of the Program. Doing so will provide economic benefit and value to ratepayers because a relatively small investment now will result in large savings to customers in the future. The tower coating program is an exemplary investment that considers repair versus replace options. In this case, repairing the asset by coating, which extends asset life, is clearly the preferred option that results in a significant present value positive investment. Hydro One has evaluated various alternatives for the Program, as described below, and concluded that the coating of 2260 (260 in 2020 and 500 in 2021-2024) corroded steel towers balances the safety and reliability risks with the economic benefits. The projected costs of the Program are estimated to be $55.5 million over the 2020-2022 test period.

of 27.5 microns will take 29 years (800/27.5=29) to lose 800 microns of thickness. Thus, a tower in C5 very high corrosion area will, on average, reach EOL in 74 years (45+29). Therefore, the window of opportunity to economically extend life of towers located in high corrosion areas via coating is when a tower reaches around 45 years and before 75 years. As the towers exceed 75 years, various level of refurbishment effort will be required to restore strength before coating can be applied. Eventually, costly refurbishment or tower replacement becomes the only feasible option.

Investment Description

The Program is a preventive maintenance investment or asset life extension program where costs are incurred today to avoid far greater costs in the future. As discussed above, Hydro One Transmission currently owns and manages 52,250 steel structures.

As part of the Program, Hydro One targets steel towers that are located in very high (C5) corrosion zones. As described previously, towers in these zones lose their protective zinc after an average of 45 years, and 10% of their metal in the following 30 years. At this stage, structures are no longer able to withstand the original design loads and either a major refurbishment or complete tower replacement would be required. Currently, there are approximately 13,000 steel towers located within very high corrosion zones. Of 13,000 steel towers, 7,500 towers have met coating criteria and are within the window of opportunity for coating. 55 percent of the 7,500 towers (4,125) are currently experiencing corrosion and metal loss. As these towers approach 75 years old, the ability to extend their service life by coating diminishes.

Hydro One intends to complete coating of an average of 452 steel towers per year between 2020 and 2024. This is a total of 2,260 towers, which are selected from the 4,125 structures that are already experiencing corrosion and metal loss.

The steel tower coating program has mainly been driven by economic considerations rather than risk mitigation. Based on the most recent analysis, the net present value

Outcome Summary:

Customer Focus	• This investment will maintain the long term reliability of the system by optimizing investment costs today and provide improved reliability and lower costs in the future.
Financial Performance	• Defer capital replacement costs by coating transmission line steel structures to preserve structural strength and extend service life.

C. EXPENDITURE PLAN

Table 2 presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical costs.

Table 2 - Total Investment Costs

($ Millions) [1]	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital and Minor Fixed Assets[2]	-	11.4	21.8	22.3	22.7	23.2	-	101.3
Less Removals	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Gross Investment Cost	**-**	**11.4**	**21.8**	**22.3**	**22.7**	**23.2**	**-**	**101.3**
Less Capital Contributions	-	0.0	0.0	0.0	0.0	0.0	-	0.0
Net Investment Cost	**-**	**11.4**	**21.8**	**22.3**	**22.7**	**23.2**	**-**	**101.3**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The following factors affect the capital expenditures required for the Program:

- Structure type/size – Depending on the voltage of the line, the structures will be different sizes. As the voltage increases, so does the size of the structure. Structure type also impacts the cost, as dead-end towers are bigger than suspension and will cost more to coat;
- Location of the structure (whether it is easily accessible or in a remote area) – Accessibility is very important, as having to clear brush and build roads adds significant costs;

SR-23 Tower Foundation Assess/Clean/Coat Program

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	57.0
Trigger(s):	Cost Avoidance, Preventative Maintenance / System Renewal, Safety, Reliability		
Outcomes:	Extends the life of foundations by re-coating them and thus preventing costly future capital investments into complex repairs or tower replacements; maintains system reliability by preventing foundation and tower failures; prevents towers from collapsing and potentially causing public injuries or fatalities		

A. OVERVIEW

Tower Foundations Assess/Clean/Coat Program (the "Program") involves coating and/or repairing steel structure tower foundations that have deteriorated to the point of increasing their risk of failure (which could include structure collapse), and impacting public safety and system reliability. The Program focuses on steel grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. The need of the Program is asset condition driven. The scope of the Program includes those steel grillage footings where coating or minor repairs can be applied to extend the foundation's service life. However, where severe corrosion has caused significant strength reduction, the steel foundation will be identified as a candidate for major repair or replacement.

The proposed plan will assess, clean, and coat 820 grillage foundations in 2020 and 1600 foundations per year from 2021-2024. Hydro One has evaluated various alternatives for the Program, as described below, and concluded that the assessing, cleaning and coating of 7220 tower foundations and anchors is the most cost effective and efficient undertaking. The projected costs of the Program are estimated to be $57.0 million over the 2020-2022 test period.

B. NEED AND OUTCOME

Investment Need

Foundations support and anchor transmission structures to the ground and enable the structures to withstand the weight of the structure itself, attached components and weather related external forces such as wind and ice. There are three dominant foundation types in Hydro One's transmission system: cast-in concrete footings, steel grillage footings, and steel anchors. Hydro One is currently focusing on grillage footings and anchors, which due to their age and material sustain a higher incidence of corrosion. Concrete footings are younger and are not displaying signs of corrosion.

From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. There are approximately 32,000 grillage footings and approximately 3,500 guyed structures which rely on the integrity of the steel grillage and anchors for support. Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. Coating life can vary considerably depending on the surrounding environment. Once the galvanizing has been depleted, the underlying bare steel begins to corrode; typically much faster than with the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the grillage foundation.

All steel grillage foundations that are in Hydro One fleet are or will be 50 years or older during the course of the next five years and, as such, will need to be assessed through the Program. When a steel grillage footing foundation reaches 50 years old, it becomes prone to degradation. Currently, 32% of steel grillage footing population is beyond its End of Service Life ("ESL"). Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions. The average ESL of the steel grillage footing fleet is 80 years. Assuming no repair and/or replacement, Hydro One anticipates that approximately 12,185 units (38% of the steel grillage footing population) will exceed their ESL by 2024 and 14,360 units (45% of the population) will exceed their ESL by 2029.

The need is determined based on foundation type and consequence of asset failure. Based on condition assessment, where severe corrosion has caused significant strength reduction, the foundation will be identified as a candidate for major repair or replacement. The failure of foundation could directly result in structure failures which could cause a lengthy system operation interruption and a possible employee or public safety concern. Furthermore, damaged foundations could result in very costly repairs or even necessitate the replacement of the entire tower.

Figure 1, Figure 2, and Figure 3 illustrate damaged grillage footings. The towers eventually had to be replaced due to the damage.

Figure 1 - Towers sitting in water causes the foundations to corrode, leading to towers leaning (circuit D2L, near North Bay, ON)

Figure 2 - Buckled legs and tower leaning (circuit M80B, Minden, ON)

Figure 3 - Leg and diagonals are corroded through, necessitating costly repairs (circuit D2L)

Investment Description

The Program is intended to inspect, assess, clean and coat the steel grillage footings buried underground, to restore any depleted coating protection and extend the foundations' service life. The Program also includes minor repairs on damaged footings and identification of footings that need major repair or replacement.

The refurbishment candidates are selected based on condition assessments. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the components. If metal loss is visible at the time of assessment, the affected components are scheduled for refurbishment.

The Program is focused on assessing, restoring, and refurbishing the grillage foundations to extend the life of the steel that is at or below the ground line. This is achieved through two planned activities:

1. Assess/Clean/Coat – This activity assesses the condition of a tower's foundation and either immediately coats it or schedules future repairs. The decision to coat or repair depends on the severity of the corrosion that is found and the complexity of potential repairs.
2. Foundation Refurbishment – This activity completes more complex repairs and/or replaces the foundations identified during previous assessment activities.

The proposed plan will assess, clean, and coat 820 grillage foundations in 2020 and 1600 foundations per year from 2021-2024. As per Hydro One strategy for steel structure and foundation, this program is to prioritize the foundations based on line voltage, type of structures and geographic location of the lines. For example, the current plan is focusing on 500 kV guyed towers located in Northern region where most of towers are located in wetland or muskeg area. These towers were built in 1960s and there is a high volume of tower foundation failures.

Outcome

The Program will maintain system reliability and mitigate public safety concerns by addressing 7,220 grillage foundations over the five year plan and extending the life of steel structure foundations.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB's Renewed Regulatory Framework:

Customer Focus	• Reduce public safety risk associated with steel tower failures • Maintain customer reliability by replacing end-of-life tower foundations
Operational Effectiveness	• Maintain system reliability by replacing end-of-life steel tower foundations • Proactive foundation replacement will reduce emergency restoration frequency

C. EXPENDITURE PLAN

Table 1 below presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs.

Table 1 - Total Investment Cost

($ Millions) [1]	**Prev. Years**	**2020**	**2021**	**2022**	**2023**	**2024**	**Forecast 2025+**	**Total**
Capital[2] and Minor Fixed Assets	0.0	11.8	22.3	22.8	23.3	23.7	0.0	104.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**11.8**	**22.3**	**22.8**	**23.3**	**23.7**	**0.0**	**104.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**11.8**	**22.3**	**22.8**	**23.3**	**23.7**	**0.0**	**104.0**

[1] *Due to the in-year nature of program investments, only 2020-2024 expenditures are shown*
[2] *Includes Overhead at current rates.*

The following are some factors that affect the cost of foundation assess/clean/coat and refurbishment:

- Structure type/size – repairing the foundation on a single leg of a 500 kV tower is much more costly than a four-leg tower. Depending on the voltage of the line, the structures will be different sizes. As the voltage increases, so does the size of the structure and its foundations;
- Location of the structure: whether it is easily accessible or in a remote/swampy area – accessibility is very important, as having to clear brush and build roads adds significant costs and some work can only be performed under frozen ground conditions;
- Environmental restrictions: whether it is a sensitive area to access – crossing an environmentally sensitive area requires time and money to be spent on permits;

Witness: Donna Jablonsky

- Work bundling – it is cheaper to work on towers that are in the same area if some costs can be shared between them; and
- The extent of the damage - the damage will determine what kind of equipment is required to perform the repairs.

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Foundation Replacement involves a reactive responding and replacing failed tower foundations and anchors that are end-of-life. This alternative has been rejected for the following reasons:

- Reactive management of tower foundations and anchors would lead to increased asset failures, resulting in elevated safety and reliability risks;
- As tower foundations and anchors deteriorate and reach end-of-life, emergency restoration and trouble call volumes would be unmanageable;
- Due to the complicated procedure to replace a tower foundation, multiple lengthy power outages will be required, which will significantly interrupt the power supply to customers and reduce system operation reliability;
- Cost of replacing a tower foundation could be as much as 20-30 times that of clean and coating the foundation, as more labour and heavy equipment is required.

Alternative 2: Planned Foundation Coating/Repair at the Optimal Level is based on assessing, cleaning and coating steel structure foundations at a rate that is coordinated with the optimal period in the foundation's life cycle at which coating and repair is most beneficial. This alternative would eliminate the backlog of eligible steel structures foundations and reduce long term planned or reactive replacement/repair costs. This alternative is preferred for the following reasons:

1. Poor condition steel structure foundations that are eligible for coating will be coated proactively
2. Risks to transmission system safety and reliability can be mitigated by balancing asset needs, resource availability, and cost impacts.

E. EXECUTION RISK AND MITIGATION

The risks to the completion of this investment include access to the assets depending on the season, availability of qualified resources and equipment outage availability. These risks are mitigated through extensive planning, scheduling and outage coordination across lines of business and stakeholders. Furthermore, a thorough risk assessment workshop is performed during the initial Program planning phase where all known risks are identified and mitigation plan is developed. For example, to address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer (i.e. switching a customer to an alternative supply). Outage planning also aims to synchronize Hydro One supply outages with the customer's planned maintenance driven outages.

Hydro One Networks – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Steel Structure Foundation Refurbishment Program
Targeted Start Date: Ongoing Program
Targeted In-service Date: Ongoing Program
Targeted Outcome: *Operational Effectiveness*

Need:
To address steel structure foundations in deteriorated condition by refurbishing those that are the highest risk to system reliability. Not proceeding with this investment will result in an increased risk failure, including structure collapse, impacting public safety and system reliability.

Investment Summary:
Hydro One Transmission currently owns and manages approximately 52,000 steel structures which are supported by a foundation, in most cases grillage (buried steel) or concrete.

From the early 1900s into the 1960s, most lattice steel structures were constructed with a grillage (buried steel) foundation. Concrete foundations were introduced as the new standard for transmission line lattice steel structures starting in the 1960s with the transition to the new standard by 1970. There are approximately 31,000 grillage footings and approximately 3,100 guyed structures which rely on the integrity of the steel grillage and anchors to support these structures. The majority of these installations are greater than 50 years old.

Steel tower grillage foundations and anchors are fabricated with a zinc-based galvanized coating which protects the underlying steel against corrosion. Coating life can vary considerably depending on the surrounding environment. Once the galvanizing has been depleted, the underlying bare steel begins to corrode and typically at a rate much faster than the galvanized coating. The accelerated corrosion results in metal loss which reduces the mechanical strength of the component.

The refurbishment candidates are based on condition assessments. If no metal loss is visible at the time of assessment, the footings and/or anchors are re-coated to restore the corrosion protection and extend the life of the component(s). If metal loss is visible at the time of assessment, the affected components are scheduled for refurbishment.

Hydro One Transmission's steel structure foundation refurbishment program is focused on assessing, restoring, and refurbishing the grillage foundations to extend the life of the steel that is at and below the ground line. The proposed plan will be to assess, coat and refurbish 700 grillage foundations each year over the test years. This represents an average refurbishment rate of 1.4% of the structures each year and is consistent with the bridge year.

Witness: Chong Kiat (CK) Ng

Alternatives:
Two alternatives were considered:
Alternative 1: Continue to maintain the assets (status quo); or
Alternative 2: Refurbishment of the assets.

Alternative 1 was considered and rejected due to asset condition and increased risk of failure. Alternative 2 is the preferred alternative as it maintains reliability and mitigates risk of failure and public safety concerns.

Basis for Budget Estimate:
The project cost is based on budgetary estimate prepared by Hydro One utilizing historical costs of projects of similar scope.

Outcome:
Maintain system reliability and mitigate public safety concerns by addressing a total of 1400 grillage foundations over the test years and extend the life of steel structure foundations.

Costs:

($ Millions)	**2017**	**2018**	**Total****
Capital* and Minor Fixed Assets	7.9	7.9	15.8
Operations, Maintenance & Administration and Removals	(0.1)	(0.1)	(0.2)
Gross Investment Cost	**7.8**	**7.8**	**15.6**
Capital Contribution	0.0	0.0	0.0
Net Investment Cost	**7.8**	**7.8**	**15.6**

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.
** This investment is part of an ongoing work program; therefore the total represents the sum of the 2017 and 2018 expenditures.

SR-25 Transmission Line Insulator Replacement

Start Date:	Q1 2019	**Priority**	High
In-Service Date:	Ongoing Program	**3Year Test Period Cost ($M):**	204.2
Trigger(s):	Strategic, Public Safety, System Reliability		
Outcomes:	Eliminate risk to public safety by replacing defective porcelain insulators; maintain customer and system reliability		

A. OVERVIEW

Transmission Lines Insulator Replacement Program (the "Program") involves primarily the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982. These defective insulators are used province-wide in Hydro One's transmission system. The defect associated with porcelain insulators results in two failure modes: (i) mechanical failure, which cause the conductor to fall on the ground; and (ii) electrical failure which triggers a forced outage, sometimes for a prolonged period of time. These types of failures pose significant safety and system reliability concerns. Hydro One retained a third-party expert, the Electric Power Research Institute ("EPRI"), to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement. EPRI completed laboratory testing which provided overwhelming evidence to support taking immediate action to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation made by EPRI is that the population of defective COB and CP insulators installed between 1965 and 1982 be removed from service as soon as practically possible.

This Program will also address the replacement of deteriorated polymer insulators. Polymer insulators in 230 kV dead-end configurations are known to fail due to their exposure to high electric-field gradients that cause silicone degradation. The degradation exposes the fiberglass rod to moisture which causes rapid deterioration leading to failure. Hydro One retained EPRI to perform a detailed condition assessment of polymer insulators to assist Hydro One in determining the need and pacing of polymer insulator replacement. EPRI completed laboratory testing and provided technical data showing that condition varies based on voltage, manufacturer and use of corona rings. The results of this study indicate that Hydro One should plan to remove certain 230 kV insulators which show extensive degradation from service as soon as possible due to immediate or high risk of failure. Other types of 230 kV insulators should continue to be assessed periodically for signs and degree of degradation. EPRI further recommends that field staff should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. As part of the Program, Hydro One will be replacing the deteriorated polymer insulators on an "as-needed" basis. Prior to replacing the polymer insulators, Hydro One will perform an asset condition assessment to ensure that the condition of a polymer insulator warrants a replacement.

Program pacing is mainly influenced by the number of defective porcelain insulators located in publicly accessible (critical) locations. Publicly accessible (critical) locations include structures located near roads, water railways, urban areas, golf courses, educational and health care facilities. Hydro One plans to replace defective porcelain insulators posing a higher public safety risk (i.e. insulators in critical locations) by 2022 at a rate of approximately 3,700 circuit structures per year. Insulators in non-publically accessible areas will be replaced at an approximate rate of 3,450 circuit structures per year over a five-year period. The projected costs of the Program are estimated to be $204.2 million over the 2020-2022 test period and the replacement quantities include both porcelain and polymer insulator replacement.

There are approximately 437,000 insulator strings in Hydro One's overhead transmission network. As described in TSP Section 2.2.2.4, Hydro One has three types of transmission line insulators in its fleet: porcelain, glass and polymer. The percentages of insulators by material type are shown in Figure 2. The scope of the Program includes defective porcelain insulators and deteriorated polymer insulators.

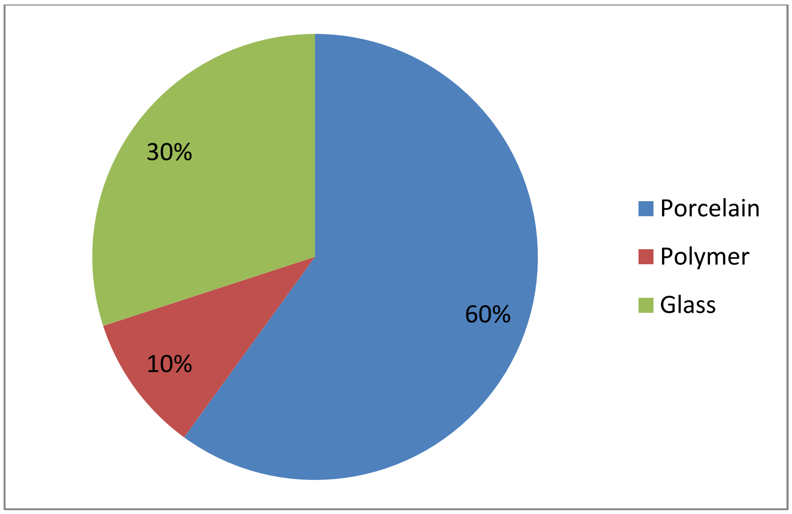


Figure 2 - Percentage of Insulators by Material

<u>Defective Porcelain Insulators</u>

Age demographics are not a driving factor for the replacement of porcelain or glass insulators since these types of insulators generally expected to outlast the life of the transmission line. However, porcelain insulators manufactured by Canadian Ohio Brass and Canadian Porcelain between 1965 and 1982 suffer from a phenomenon known as cement expansion or cement growth, as shown in Figure 3 below. It is recognized throughout the industry, that both the electrical and mechanical characteristics of line insulators manufactured between the mid-1960s and early 1980s by COB and CP deteriorate faster than other comparable insulators due to cement expansion.

Figure 5 - V76R Insulator Failure

Figure 6 - HL3 Insulator Failure

The porcelain insulators manufactured by COB and CP are used province-wide in Hydro One's transmission system. There are approximately 34,000 circuit structures with defective porcelain insulators and roughly 15,000 have been identified as being on structures in publicly-accessible (critical) locations. Publicly-accessible (critical) structures include those located near roads, water railways, urban areas, golf courses, educational and health care facilities. To date approximately 8,900 publicly- accessible COB and CP insulators have been replaced. A breakdown of the defective population in relation to the total insulator population can be seen in Figure 7.

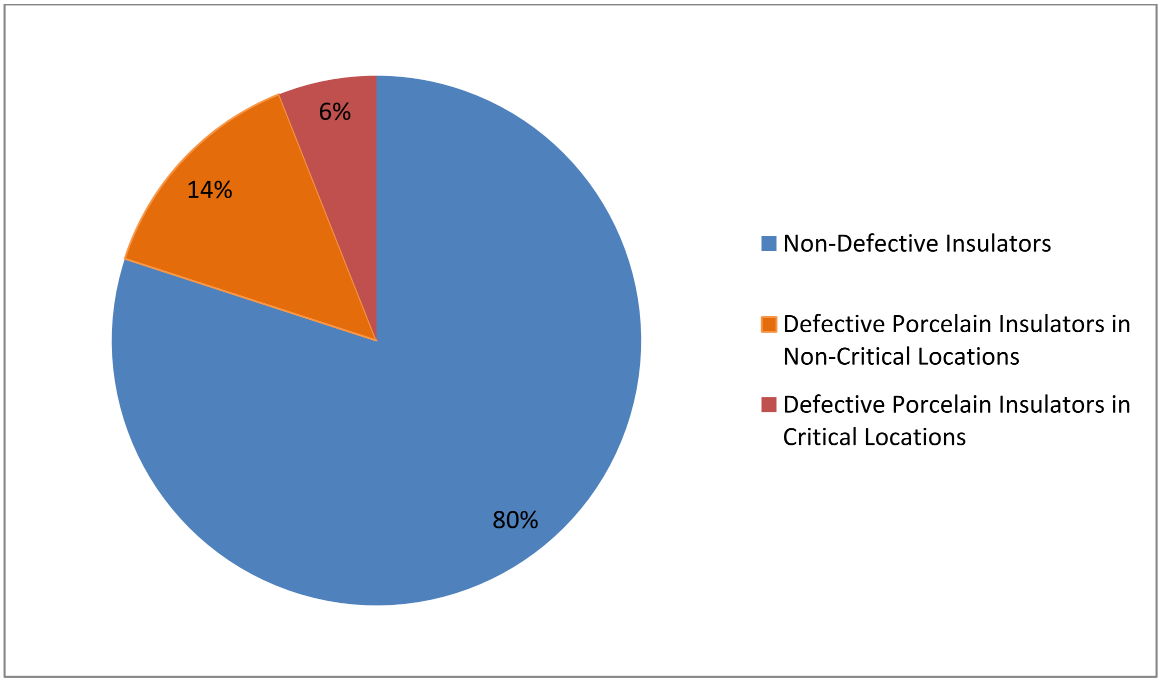


Figure 7 - Defective Porcelain Insulator Population

Figure 8 illustrates the number of COB and CP failures over the past ten years, showing an increasing trend. The number of failures is expected to rise due to the degradation of the known defective COB and CP porcelain insulators, potentially impacting public safety, system performance and customer reliability. Failed insulators normally result in a sustained forced outage due to the permanent electrical fault they create. Repair time can be significant, averaging 37 hours, depending on the location and severity of the failure.

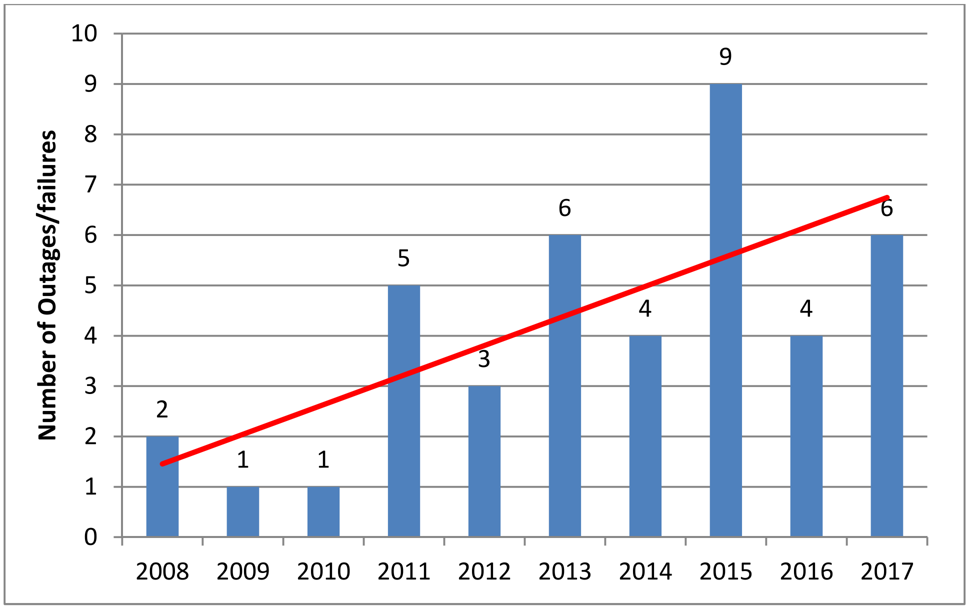


Figure 8 - Frequency of COB/CP Insulator Failures

To address concerns associated with defective porcelain insulators, Hydro One retained a third party expert, EPRI. EPRI performed laboratory testing on COB and CP porcelain insulators in order to assess the condition of defective COB and CP porcelain insulators to assist Hydro One in determining the pacing of porcelain insulator replacement. The testing program comprised of two phases. Based on the Phase one COB and CP testing results, Hydro One significantly increased the insulator replacement rate, compared to pre-2016 levels, and prioritized the replacement of insulators in publically accessible (critical) locations.

Phase one was completed in 2016 and included testing of 299 insulators removed from a combination of dead-end and suspension strings installed in publicly-accessible (critical) locations. Phase one testing was intended to provide an expedient assessment of the condition of the in-service insulators in question. The results of phase one supported the urgent replacement of COB and CP insulators manufactured between 1965 and 1982 that are installed in publicly-accessible (critical) structures where public safety is at risk.

Witness: Donna Jablonsky

A large proportion of the insulators tested (37%) during phase one failed electrically or mechanically at loads below their rated M&E strength. There was a significant number of punctured insulators and the test data showed a large variation in failing loads which would not be expected for a healthy insulator population. The condition of the Hydro One insulators was assessed through benchmarking against EPRI and public domain test data. This benchmarking data was obtained through testing of similar vintage insulators which had been in service for a comparable duration under similar field conditions. The performance of the Hydro One and the benchmarking insulators was also compared to current and historical requirements for new insulators. The test results presented an initial snapshot of the condition of the population of defective insulators in-service on Hydro One's transmission system. Although the sample of insulators tested was not sufficient to perform a rigorous statistical analysis upon which to base recommendations, the results strongly suggested that the installed insulator population comprising CP and COB insulators manufactured between 1965 and 1982 had reached or was at least approaching the end of useful life.

Phase two of the testing was performed in 2017. Those tests were carried out on 591 insulators. The intent of the phase two tests was to supplement the phase one data and to provide data on the rate of deterioration of the insulator population. The results of analysis showed that:

- a large number of the tested insulators exhibited porcelain cracking after M&E testing
- the propensity for the insulators to puncture (crack) during Thermal Mechanical Cycling (TMC);
- the fact that the insulators are highly susceptible to electrical puncture under steep transient voltages (e.g. lightning);
- the finding that TMC drastically decreases the already weak ability of the insulators to withstand electrical puncture; and
- a significant number of insulators separated mechanically during TMC.

These results suggest that the number of in-service punctured units will increase as the insulators experience significant mechanical loading events. When a string containing electrically punctured insulators undergoes a flashover due to lightning, contamination, or snow and ice bridging, there is a high likelihood that the ensuing power arc will pass through the punctured unit internally travelling from cap to pin, causing significant heating and pressure buildup which can cause the cap and pin to separate and the conductor to drop. The greater the number of punctured insulators found in the string, the higher the probability of string flashover and string separation. Insulators which are not punctured, but have suffered deterioration in mechanical strength do not exhibit this behavior. If a string contains mechanically compromised units, the insulators will fail if the maximum applied load exceeds the units remaining mechanical strength. The majority of conductor drops recently experienced on Hydro One's porcelain insulated transmission system fall into the former category.

The phase one and two analyses provided overwhelming evidence supporting replacement of defective porcelain insulators to mitigate the risk to the safety and reliability of Hydro One's transmission system. The key recommendation provided by EPRI is that the identified population of COB and CP insulators be removed from service as soon as practically possible.

Deteriorated Polymer Insulators

Hydro One uses polymer insulators on the 115 kV and 230 kV transmission system. Polymer insulators have an Expected Service Life[1] ("ESL") of 30 years and, due to their material properties, degrade with age. First-generation polymers installed in the mid-1980s will reach their ESL during the test period and need to be evaluated for

[1] Hydro One defines ESL as the average age in years that an asset can be expected to operate under normal system conditions.

- Dye Penetration Testing;
- Water Vapor Ingress Testing; and
- Moisture Penetration Test of the End-fittings.

The following are the key findings of EPRI condition assessment analysis:

Visual inspection showed that:

- The 230 kV K-Line insulators with the 4-inch donut corona ring have an extremely high likelihood of electrical and/or mechanical failure due inadequate control of the electric field on the surface of the rubber housing at the line-end. The rubber housing at the line-end of these insulators has been severely eroded leading to exposure of the fiberglass rod. Such exposure of the rod will result in either mechanical or electrical failure with a high probability of the insulator parting and causing a conductor drop. Smaller (4-inch) corona rings were used on earlier generations of polymer insulators. When older polymer insulators were designed and manufactured, the long-term effects of electric fields were not well understood and it was standard practice to use small or no corona rings which caused unexpected polymer degradation. Newer generation polymer insulators use modified designs and refined manufacturing techniques.
- The 230 kV NGK insulators installed without corona rings are showing signs of serious deterioration of the line-end rubber housing and deterioration of the secondary seal. As such, they are considered to have a high risk of failure.
- The 230 kV NGK insulators installed with 8-inch corona rings are experiencing rubber housing damage at the line-end. Currently this deterioration does not appear overly serious, but it is not known how quickly the housing deterioration will progress. In the EPRI aging chamber and at one EPRI member utility site this deterioration did result in eventual failure.

Dye penetration testing showed that:

- Each of the insulator groups with the exception of the Ohio Brass insulators had a single insulator unable to meet the dye penetration test requirements.

Water vapor ingress testing showed that:

- Seven 230 kV K-Line insulators exhibited low resistance along their length after humidity conditioning. Of these seven, three had damage from power arcs and housing erosion which may explain their failure. The remaining four (all of which had 8-inch corona rings) will be further examined to determine the root cause of failure.

End-fitting moisture penetration tests showed that:

- All but three insulators passed the test. Of the failing three units, two have been in service for 26 and 27 years, and the third had major line-end rubber erosion and rod exposure.

At the conclusion of its condition assessment analysis, EPRI provided Hydro One with its recommendations. Key EPRI recommendations are as follows:

- All 230 kV K-Line insulators fitted with 4-inch donut corona rings should be removed from service as soon as possible since they pose a proven risk of immediate failure.
- All the 230 kV NGK insulators installed without corona rings should be removed from service as they are considered to be at high risk of failure.
- All the 230 kV Ohio Brass insulators installed without corona rings should be removed from service.
- The seven 230 kV K-Line insulators which failed the water vapor ingress test should be subjected to additional testing followed by dissection to quantify the degree of concern which should be associated with their failing the water vapor ingress test. This type of issue is generally associated with poor bonding between

the housing and the rod and is often a batch problem. Until the issue is understood, these insulators should not be maintained live without first checking their integrity with the EPRI-developed insulator tester.

Hydro One is using this information to optimize the overall replacement program with respect to the risk of in-service failure. Hydro One will be using the results and recommendations of the EPRI study to develop a polymer insulator replacement strategy. Hydro One will leverage current condition assessment and patrol programs to locate polymer insulators that were identified by EPRI and target them for replacement.

Investment Description

Transmission line insulators cannot be maintained or repaired to extend their service life; therefore, defective porcelain insulators and end-of-life polymer insulators are targeted for replacement as part of the Program. The defective porcelain insulators will be replaced with either glass type or porcelain type insulators. Replacements of defective porcelain insulators will be prioritized based on locations posing a higher public safety risk. The deteriorated polymer insulators will be replaced with either glass, polymer, or porcelain type insulators. Due to their longer ESL porcelain and glass are the preferred insulator types and are used wherever practical. However, polymer insulators will be considered when their material properties prove beneficial (i.e. in areas with high contamination).

Hydro One has approximately 34,000 circuit structures with defective porcelain insulators and roughly 15,000 have been identified as being on structures in publicly-accessible (critical) locations. Publicly-accessible (critical) structures include those located near roads, water railways, urban areas, golf courses, educational and health care facilities. As such, defective porcelain insulators posing a higher public safety risk (i.e. insulators in critical locations) are to be replaced by 2022 at a rate of approximately 3,700 circuit structures per year. Insulators in non-publicly- accessible areas will be replaced at an approximate rate of 3,450 circuit structures per year over a five-year period beginning in 2022.

Outcome

As a result of the Program, Hydro One will reduce public safety risk associated with insulator failures resulting in conductor drops and maintain system reliability by removing electrically and/or mechanically compromised insulators that may cause forced outages.

The following table presents anticipated benefits as a result of the Program in accordance with the OEB Renewed Regulatory Framework:

Outcome Summary:

Customer Focus	• Eliminate public safety risk associated with defective porcelain insulators • Maintain system and customer reliability by replacing defective and/or end-of-life insulators
Operational Effectiveness	• Maintain system and customer reliability by replacing defective and/or end-of-life insulators

C. EXPENDITURE PLAN

As discussed above, the Program is primarily needed to replace the defective COB and CP porcelain insulators that pose significant public safety and system reliability risks. Hydro One will strive to complete the Program in an effective and efficient way to minimize the cost of performing this sustainment task. The Program starts in January and ends in December of each of the test years.

Table 1 below presents forecasted costs for the Program. Costs for the Program are based on an average unit cost estimate calculated utilizing historical replacement costs. The replacement costs are influenced by the voltage level, structure type and accessibility.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	74.2	75.7	72.0	73.5	74.9	0.0	370.3
Less Removals	0.0	5.9	6.1	5.8	5.9	6.0	0.0	29.6
Gross Investment Cost	**0.0**	**68.3**	**69.7**	**66.3**	**67.6**	**68.9**	**0.0**	**340.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**68.3**	**69.7**	**66.3**	**67.6**	**68.9**	**0.0**	**340.7**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

D. ALTERNATIVES:

Hydro One considered the following alternatives before selecting the preferred undertaking:

Alternative 1: The "Do Nothing" - Reactive Replacement of Failed Insulators involves reactive replacement insulators as they fail. This alternative has been rejected due to the unacceptable public safety risk that may arise when a failure results in a conductor drop in a public area. Due to the continued degradation of these defective insulators the number of failures is expected to rise, negatively affecting safety, reliability and customer satisfaction. Furthermore, a systemic investment approach is needed to pace replacements to minimize the impact to customers and reliability.

Alternative 2: Planned Insulator Replacement is a recommended undertaking. This alternative involves planned replacement of defective porcelain and end-of-life polymer insulators prior to failure. This alternative is recommended as it will reduce the risk to public safety. In addition, it will enable investment pacing and outage planning to mitigate customer and reliability impacts.

Witness: Donna Jablonsky

E. EXECUTION RISK AND MITIGATION

Risks that can impact the completion of the insulator replacement program include: outage constraints, resource constraints, construction execution challenges, customer coordination, and procurement challenges. To address outage constraints, Hydro One develops a planned outage coordination plan. This plan is the operation plan with the goal to eliminate or minimize the loss of supply to the customer. The plan might include switching a customer to an alternative supply. Outage planning also aims to synchronize Hydro One supply outages with the customer’s planned maintenance driven outages.

SR-26 Transmission Line Emergency Restoration

Start Date:	Q1 2020	**Priority:**	High
In-Service Date:	Ongoing Program	**3Year Test Period Cost ($M):**	29.4
Trigger(s):	Corrective Maintenance, Safety, Reliability		
Outcomes:	Align with obligations with TSC; make safe and minimize public/employee safety risk, improve customer satisfaction by carrying out replacement in a timely manner to minimize unplanned customer interruptions; maintain transmission system reliability,		

A. OVERVIEW

Transmission Lines Emergency Replacement program is reactive in nature, mainly to provide an immediate response to an emergency situation or to prevent or minimize the effects of an emergency situation. This investment program funds the emergency replacements of transmission line components that have failed or identified to be in imminent danger of failure. A failed or deficient transmission line component may cause an impact on the transmission system that varies from being minor to significant. It poses safety risk as well as power delivery risk which might affect regional load flow limits and customer operations. As a licensed transmitter, Hydro One is legally obligated to comply with the planning, operating and reliability criteria and standards imposed by the Transmission System Code (“TSC”). This investment program ensures that Hydro One continues to comply with its commitment and legal obligations to mitigate safety, system reliability and environmental risks that an unforeseen failure might cause.

B. NEED AND OUTCOME

Investment Need

Hydro One’s transmission system extends to most of the province and operates in diverse geographic and climatic conditions. Hydro One operates transmission lines primarily at 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. These lines are used to transmit electric power to connected commercial and industrial customers, as well as to Local Distribution Companies (“LDC”) who in turn distribute the power to their end-use customers.

Customer Focus	• Improve customer satisfaction by minimizing interruptions and providing timely power restoration to customers
Operational Effectiveness	• Minimize public/safety risk and system reliability impact by repairing and/or replacing assets that failed or are at risk of imminent failure. • Comply with TSC obligations by providing safe and reliable electricity to Ontario electric consumers.

C. EXPENDITURE PLAN

Table 1 below presents forecasted planned expenditures for this investment program. The planned expenditures are based on historical spending. Historically the actual expenditure of this program is in line with the planned expenditure. For program work, cash flows are only shown for the five year period. Program work is started and completed in-year.

Table 1 - Total Investment Cost

($ Millions)[1]	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[2] and Minor Fixed Assets	0.0	10.4	10.7	10.9	11.1	11.3	0.0	54.3
Less Removals	0.0	0.8	0.9	0.9	0.9	0.9	0.0	4.3
Gross Investment Cost	**0.0**	**9.6**	**9.8**	**10.0**	**10.2**	**10.4**	**0.0**	**50.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**9.6**	**9.8**	**10.0**	**10.2**	**10.4**	**0.0**	**50.0**

[1] Due to the in-year nature of program investments, only 2020-2024 expenditures are shown
[2] Includes Overhead at current rates.

future reliability issues. Reliability risk provides a comparable illustration of the potential for reliability issues over time. Reliability risk assessment is a proactive measure to mitigate risks before reliability performance starts to deteriorate and negatively impact customers.

To improve reliability and meet the targets over the test year period, Hydro One commissioned a number of third party expert studies to validate Hydro One's approach to managing specific types of transmission assets (see TSP Section 1.4). Hydro One has included specific projects in the Business Plan to replace equipment due to asset condition and performance. Investments to replace some of these assets are described in Investment Summary Documents, including but not limited to:

- Air Blast Breaker Replacement Project – SR-01;
- Line Replacements – SR-19, SR-20;
- Transformer Replacements – SR-03, SR-05; and
- Protection Replacements – SR-07, SR-10.

Asset & Project Management: Transmission System Plan Implementation Progress

In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business, and reported as a percentage value relative to the transmission plan. For 2018, the TSP implementation achieved 99 per cent of the planned in-service capital expenditures, including the OEB carry-forward variance.

Hydro One's average performance over the past five years (2014-18) was 99 per cent of the TSP, and the company's past performance trend is flat (see Figure 11).
Over the plan period, Hydro One aims to improve against its five-year average, and complete 100 per cent of the TSP.

Table 1, the first three are related to delivery point ("DP")[1] performance and the last one is based on transmission equipment performance.

Delivery performance is measured by the frequency of delivery point interruptions, the duration of delivery point interruptions and the delivery point unreliability index which is a normalized measure of estimated unsupplied energy to customers. All interruptions caused by forced outage are included in these measures. For equipment performance, transmission system forced unavailability is used.

Table 1: Transmission Reliability Measures

Perspective	Measure	Description
Reliability of Delivery of Electricity to Customers	Frequency of Delivery Point Interruptions	Average number of interruptions experienced at delivery points due to forced interruptions
	Duration of Delivery Point Interruptions	Average interruption duration in minutes experienced at delivery points due to forced interruptions
	Delivery Point Unreliability Index – a measure of unsupplied energy	Energy not supplied to customers caused by forced interruptions, normalized by system peak load and presented in System Minutes
Performance of Transmission Equipment	Transmission Equipment Unavailability	Extent to which transmission equipment is not available due to forced outages

Hydro One's rationale for employing these measures is as follows:

- These metrics are commonly used transmission reliability measures in the industry, especially in Canada. As a group, the measures address transmission service reliability, which is important to customers and stakeholders.

[1] Delivery points are generally defined as the interfaces between Hydro One's transmission system and its load customers. Delivery Points are either (a) low voltage buses at Hydro One owned step-down transformer stations, or (b) stations owned by transmission load customers, including Hydro One distribution stations and transmission directly connected customers.

SEC INTERROGATORY #44

Reference:

Interrogatory:

For each year between 2012 and 2018, please provide a table that shows:

a) T-SAIDI for the single circuit system broken down by cause code.

b) T-SAIFI for the double circuit system broken down by cause code.

c) T-SAIDI for the double circuit system broken down by cause code.

d) T-SAIFI for the double circuit system broken down by cause code.

Response:

a) T-SAIDI for the single circuit system broken down by cause code.

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
BES CONDIT_N	0.3215	9.187	0.7099	0.2349	0.3268	1.4026	2.0261
CONFIGURAT_N	11.556	13.4948	3.5874	5.0071	1.7953	2.2382	8.9548
ENVIRONMENT	142.0908	0.1283	0.0000	0.0000	10.2026	0.0000	0.0000
EQUIPMENT	25.6946	88.196	69.4151	62.9126	213.1896	70.5395	78.2705
FOREIGN	21.4308	43.3745	9.5794	26.6225	26.5406	21.7032	20.9391
HUMAN	0.6666	0.07	1.8018	0.701	2.3258	11.2362	1.2869
NEIGHBOURING UTILITY	0.0000	0.0000	0.0000	0.0000	0.0000	0.9376	0.0000
SPS OPERATION	0.0000	0.0000	0.0000	0.0000	0.0654	0.0000	5.0557
UNKNOWN	7.7798	5.1009	0.899	2.0375	1.6646	0.6948	2.432
WEATHER	23.7145	35.5624	13.1646	29.0721	8.6687	25.024	83.6463
T-SAIDI	233.2545	195.1139	99.1573	126.5878	264.7791	133.7761	202.6114

Performance Category	Measure	Description
	System Unavailability (% of time system equipment is unavailable)	Transmission System Unavailability captures the total duration transmission equipment is out of service due to unplanned outages.
	Unsupplied Energy (minutes)	Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point unplanned interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. The unit of the measure of normalized unsupplied energy is expressed in “system minutes”.
Asset & Project Management	Transmission System Plan Implementation Progress	The Transmission System Plan Implementation Progress measure compares the total actual in-year sustainment, development, and operating expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.
	Capital Expenditures as % of Budget	Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures.
	Operations, Maintenance, & Administration (“OM&A”) Program Accomplishment (composite index)	The Transmission (“Tx”) OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom, 8)Infrastructure.
	Capital Program Accomplishment (composite index)	The Tx Capital Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx Capital Programs against the weighted budget. The six programs monitored for this measure include the Steel Structure Coating Program, Tx Lines Insulator Replacement Program, Tx Wood Pole Replacement, Tower Foundation Refurbishment, Shieldwire Replacement and Purchase of Station Spare Transformers.
Cost Control	Total OM&A and Capital per Gross Book Value of In-Service Assets	Demonstrates Transmission cost effectiveness by comparing the ratio of Total Capital and OM&A to Gross Book Value of Fixed Asset costs.

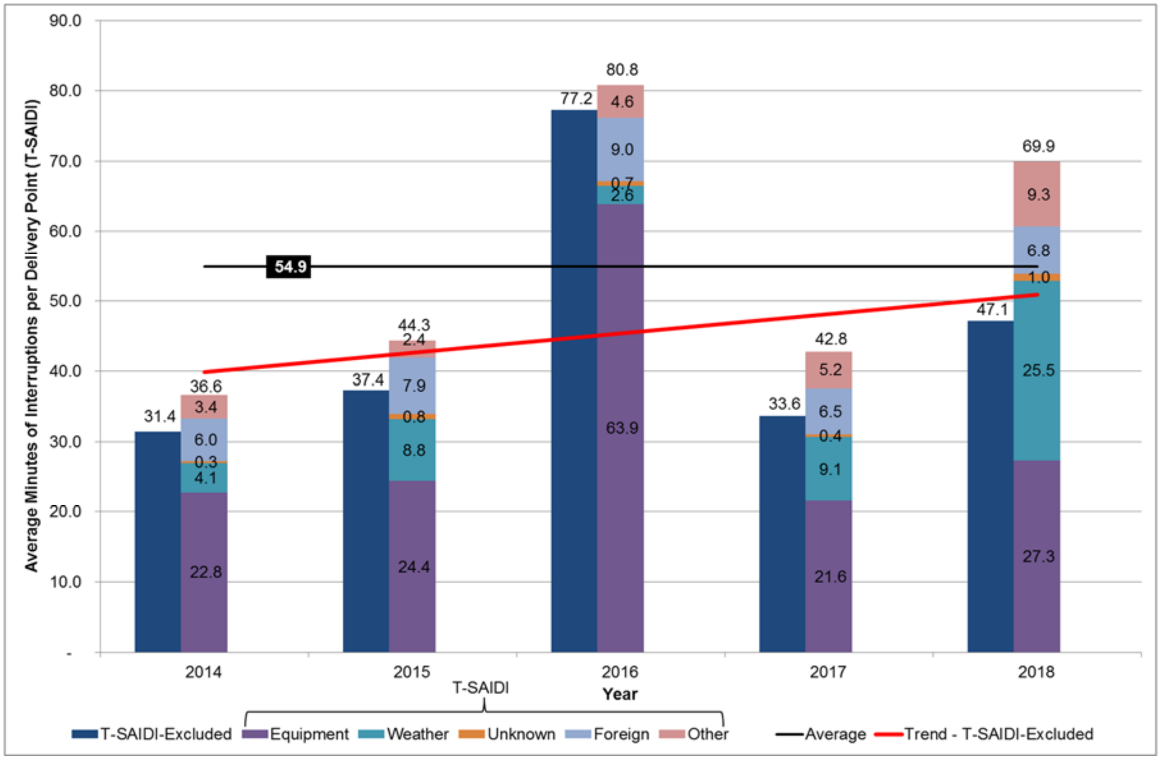


Figure 8 - Transmission System Average Interruption Duration Index (minutes)

System unavailability examines the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. This measure does not consider the subordinate outages of healthy transmission equipment removed from service as a result of an outage caused by other equipment. The information derived from monitoring this measure is trended over time and helps influence business decisions that affect the reliability of transmission equipment. This measure is specifically defined to enable comparison with all-Canada averages from all transmission utilities which participate in the Equipment Reliability Information System program of the Transmission Consultative Committee on Outage Statistics at the Canadian Electricity Association.

Witness: Bruno Jesus

System unavailability for 2018 was 0.83 per cent, and 0.15 percentage points higher compared to 2017. Increases in lines unavailability in 2018 were driven to a large extent by tornado damage on a circuit and the need to repair two separate faulted cable circuits. Increases in the unavailability of stations equipment in 2018 were driven to a large extent by the unavailability of high voltage capacitors due to issues with the capacitor itself or the capacitor breaker.

Hydro One's average performance over the past five years (2014-18) was 0.67 per cent system unavailability and the performance trend indicates an increase in system unavailability over the past five years (see Figure 9).

Over the plan period, Hydro One aims to improve against its five-year average, targeting 0.44 per cent for system unavailability.

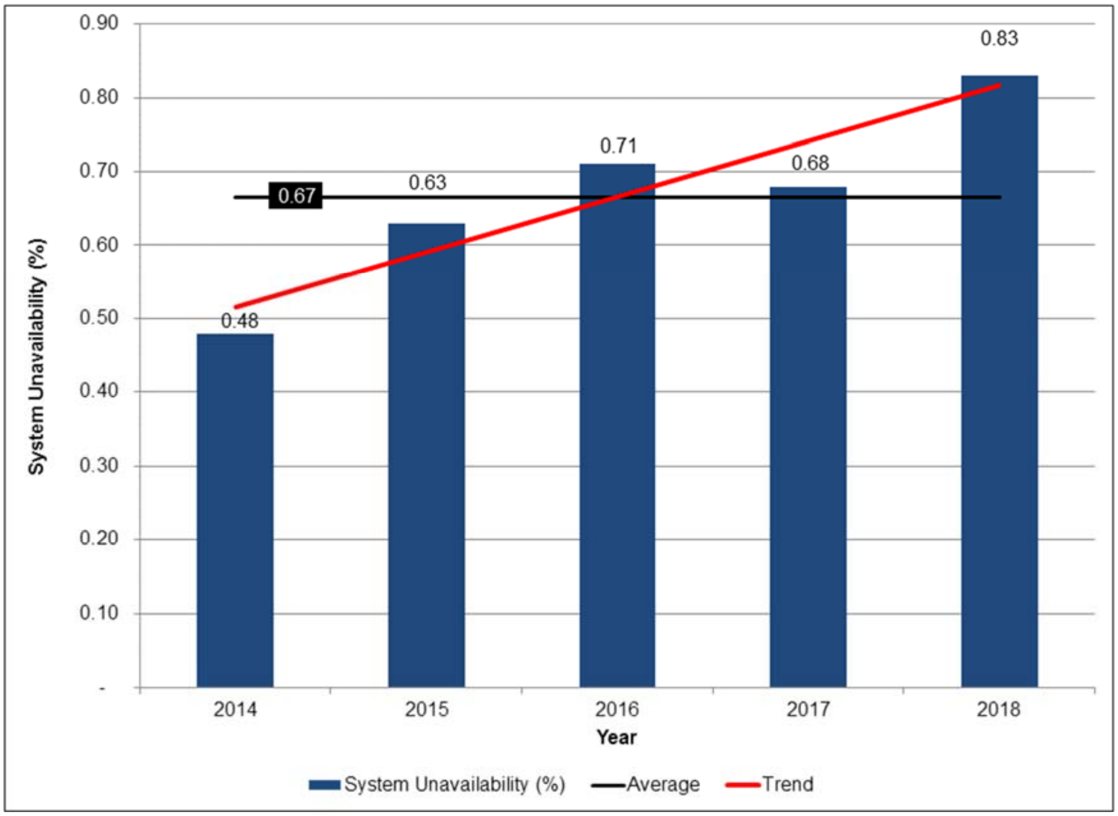


Figure 9 - System Unavailability (in %)

Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to make the performance comparable to that of other utilities.

Unsupplied Energy for 2018 was 19.5 system minutes, higher by approximately 6 minutes or about 48 per cent compared to 2017 primarily due to more weather-caused interruptions such as a large freezing rain event on April 14th and large wind event on May 4th.

Hydro One's average performance over the past five years (2014-18) was 13.6 system minutes of unsupplied energy, and the performance trend is showing a deterioration or an future reliability issues. Reliability risk provides a comparable illustration of the potential for reliability issues over time. Reliability risk assessment is a proactive measure to mitigate risks before reliability performance starts to deteriorate and negatively impact customers.

To improve reliability and meet the targets over the test year period, Hydro One commissioned a number of third party expert studies to validate Hydro One's approach to managing specific types of transmission assets (see TSP Section 1.4). Hydro One has included specific projects in the Business Plan to replace equipment due to asset condition and performance. Investments to replace some of these assets are described in Investment Summary Documents, including but not limited to:

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Hydro One's average performance over the past five years (2014-18) was 99 per cent of the TSP, and the company's past performance trend is flat (see Figure 11).
Over the plan period, Hydro One aims to improve against its five-year average, and complete 100 per cent of the TSP.