EB-2019-0018

HYDRO ONE TRANSMISSION EB-2019-0082

VECC COMPENDIUM

Panel 1

October 24, 2019

TAB 1

condition) to be further evaluated against the relevant planning context. The investment candidates are further scored and prioritized through Hydro One's Investment Planning process (as described in TSP Section 2.1.4 below) to achieve the optimal balance of risk and benefits.

Hydro One performs a continuous asset risk assessment ("ARA") process to determine individual asset needs which rely on asset condition data, engineering analysis and other information including the input of experienced planning professionals. The ARA is primarily concerned with the major equipment groups (e.g. transformers, conductors, breakers, and protection and control systems) that directly affect system reliability.

One of the inputs into the ARA is a quantitative asset analytics system, which combines information from various Hydro One databases to provide an initial common understanding of asset health. This process drives efficiency and effective planning decisions by ensuring a consistent view of asset information for all planners. As part of the preliminary risk assessment, asset analytics enables the review and consolidation of a variety of information from enterprise reporting systems, such as condition information driven by deficiency and preventive maintenance reports, demographic information including make, model, and type, criticality to the transmission system, performance data based on equipment outages, utilization information, and economics. While not a determinative driver in the ARA process, asset analytics is one useful tool that aids Hydro One planners in identifying asset risks for further screening and confirmation. Hydro One's planners also take into account additional factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets. As part of the ARA process, transmission assets are evaluated on the following six risk factors:

- **Condition** - Risk related to the increased probability of failure that assets experience when their condition degrades over time. Asset condition is defined using different criteria, depending on the asset. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.
- **Demographics** - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages. Assets with relatively high demographic risk are candidates for refurbishment or replacement.
- **Criticality** - Represents the impact that the failure of a specific asset would have on the transmission system. Primarily, it is used to show relative importance of an asset compared to other assets of the same type. Assets whose failure would result in an interruption to a larger amount of load would have an asset criticality that is higher than assets whose failure would have a smaller impact on the system load. Asset criticality is used to prioritize the refurbishment or replacement of assets whose condition, demographic, performance, utilization or economic risk has already resulted in the asset being considered a candidate for refurbishment or replacement.
- **Performance** - Risk that reflects the historical performance of an asset, derived from the frequency and duration of outages. Past performance can be a good indicator of expected future performance. Therefore, assets with a relatively high-performance risk can be considered candidates for refurbishment or replacement.
- **Utilization** - Risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized. The relative deterioration of some assets is highly

dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded relative to their nameplate rating deteriorate more quickly than those that are lightly loaded. Similarly, circuit breakers utilized for capacitor and reactor switching which are subject to significant operations experience accelerated mechanical and electrical wear-out of the breaker. Therefore, the asset utilization risk for transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operational history, respectively.

- **Economics** - Risk based on the economic evaluation of the ongoing costs associated with the operation of an asset. Depending on the asset type, this evaluation may be as simple as determining the replacement cost of the asset, or as complex as comparing the present value of ongoing maintenance to that of complete refurbishment or replacement. While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

It is important to recognize that although asset analytics aids in the identification of asset needs as an initial step, it is not the sole input or driver of the ARA. Hydro One planners take into account a range of other considerations and data sources, as informed by sound engineering oversight and experience-based decision making, in the initial determination of asset needs, which are then ultimately verified against asset condition assessments.

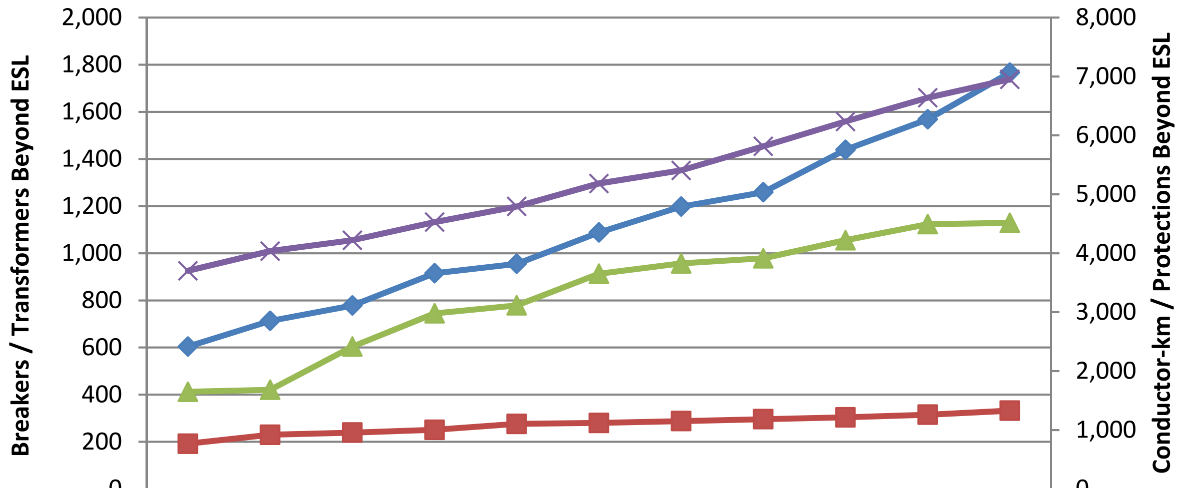
Throughout the assessment of individual asset needs, Hydro One’s planners carry out a process of grouping identified needs into logical, functional and geographic groups. For example, a customer need for increased capacity and an asset need to replace transmission station equipment, such as a transformer or switchgear, might be grouped together if the same transmission station is involved. Through this process, diverse individual needs are brought together to form potential projects or programs that may be

3.3.5 (5.4.2, 5.4.3.1) FORECAST AND HISTORICAL ASSET REPLACEMENT RATES

Hydro One's planned replacement rates are derived through the processes described in TSP Section 2.1, based on the assessment of the assets and system needs and asset lifecycle optimization (see TSP Sections 2.2 and 2.3). The historical and forecast rate of replacement for transmission stations and lines assets are noted in Tables 3 and 4 below.

The replacement rates shown below are the culmination of Hydro One's asset management and investment planning processes. In the context of System Renewal, for example, these processes have resulted in striking a balance between the asset needs (arising from age, condition, environmental and regulatory compliance), customer needs and preferences, and bill impact. Given the demographic pressures and impending wave of assets that will be at the end of their expected service life ("ESL") within the TSP period, Hydro One identified the following trends for each of the asset groups:

- Transformers – the proposed rate of replacement is largely in line with historical rates, and will ultimately maintain the percentage of the transformer fleet that operates at or beyond ESL
- Breakers – the proposed rate of replacement maintains the percentage of the breaker fleet that is operating beyond ESL at 12%.
- Protections – the proposed rate of replacement maintains protection systems that operate beyond their ESL at the current 27%.
- Conductor – the proposed rate of replacement mitigates the risk by managing the current 5% of conductor fleet that operates beyond ESL. Otherwise, the percentage of the conductor fleet operating beyond their ESL would have been 13% in the next five years which would create a high risk to manage.
- Wood Pole – the proposed rate of replacement maintains system reliability with a customer focus, as majority of wood poles are located in northern Ontario and



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	192	230	239	251	276	280	288	296	304	315	332
Conductor	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952

Figure 1 - Number of Assets beyond ESL per Year Summary

Hydro One tracks asset utilization for certain assets and asset classes. However, utilization is not the ultimate driving factor in asset replacement decisions.[1] Utilization is defined by major asset class using available and applicable asset characteristics. In the case of transformers, utilization is defined by historical loading as a ratio of the nameplate capacity rating. Utilization for breakers is defined as a combination of the total count of operations, breaker nameplate fault rating relative to available system fault

[1] There have been instances where Hydro One replaced assets with higher rated equipment to satisfy system performance standards pursuant to the IESO Market Rules and/or Transmission System Code (Appendix 2). For example, to enable the connection of distribution generation facilities, a number of equipment replacements were made around 2009 so as to increase short circuit capacity and thermal ratings of stations and lines.

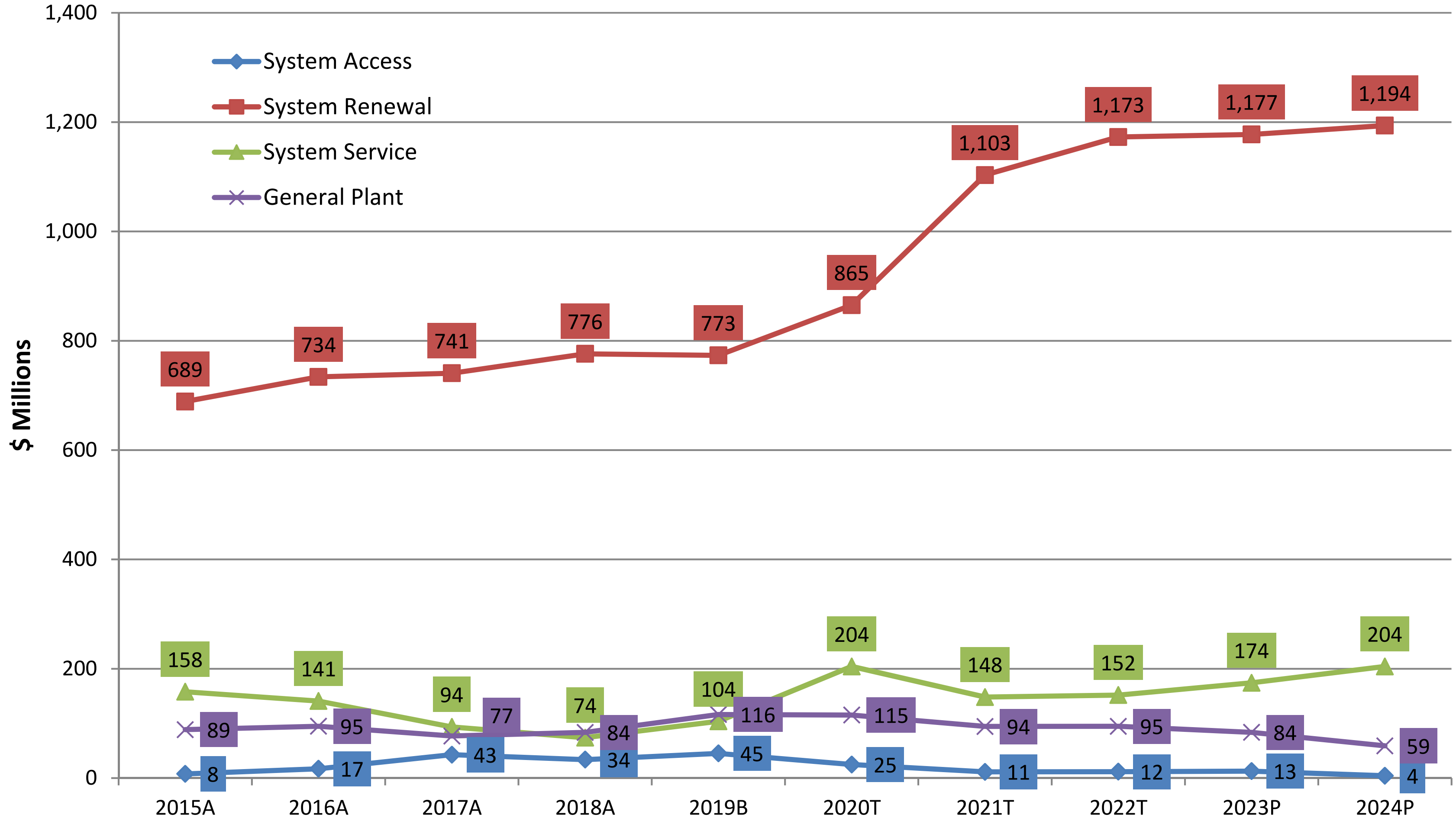


Figure 1 - Actual / Forecast Capital Expenditures 2015 - 2024 by Category

(A=Actual, B=Bridge Forecast, T=Test Forecast, P=Plan)

TAB 2

GP-12 Transport & Work Equipment

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Program	**3 Year Test Period Cost ($M):**	39.7
Trigger(s): Productivity Enablement and Cost Avoidance			
Outcomes: Optimize fleet service levels, maximize equipment efficiencies, reduce required repairs and minimize equipment downtime, maintain regulatory compliance			

A. OVERVIEW

The Transport & Work Equipment ("TWE" or "Fleet") program involves the replacement of end-of-life fleet vehicles and helicopters. The program is driven by the need to replace these vehicles based on a thorough review of age, mileage and overall condition, and by the requirement to support Hydro One work programs and staffing requirements (including transmission and distribution capital and Operations, Maintenance & Administration ("OM&A") sustainment, development and operations work programs). This program will result in optimized fleet service levels to mitigate potential delays in response time to unplanned customer incidents, such as trouble calls and storm response and optimal levels of availability of fleet vehicles and other specialized equipment to reduce human effort and minimize risk of personal injury in the field. This program will also benefit employees by ensuring that employees have the right equipment to do their job, thereby increasing employee engagement levels, minimizing risk of injury and increasing work satisfaction. This investment will allow for maximum equipment efficiencies and ensure compliance with all codes, standards and regulations to sustainably manage our environmental footprint. The projected costs of the program are estimated to be $ 66.3 million over the 2020-2024 plan period.

Asset Condition / Demographics

Hydro One has approximately 7,000 vehicles and other fleet equipment. Table 26 shows the breakdown of the Fleet asset demographics and their current condition. Fleet Management Services and the LOB complete annual asset reviews. Assets are identified for replacement based on their ESL and mileage which are recommended by the manufacturers as a guideline to initially identify vehicles for replacement. Specialized technicians will assess the condition of the asset to determine if the asset can be retained for an additional period of time or if it needs to be replaced.

Table 26 - Average Age and ESL of TWE[1]

Equipment Type	Quantity of TWE Fleet (%)	Average Age (Years)	Average Mileage (kms)	ESL (Years)	ESL (kms)
Light	37.8%	4	108,000	6	180,000
Heavy	19.5%	7	127,000	8-14	300,000-400,000
Off-Road	6.6%	8	N/A	individual asset assessment	
Miscellaneous	36.1%	8	N/A	individual asset assessment	
Helicopters	0.1%	15	N/A	individual asset assessment	

[1] *Data from December 31, 2018*

Condition

Hydro One specialized technicians monitor and asses the condition of the transport and work equipment during inspections and routine maintenance. Adequate maintenance and service intervals help to reduce degradation of the equipment and maximize the life of the asset. The condition of the assets, along with the age and kilometres driven/hours used, determine the need for replacement and any risks that need to be mitigated.

Future Outlook / Need

Fleet requirements for asset replacement are primarily based on industry standards or manufacturers' recommendations for life cycle expectancy. This includes age and kilometres driven as well as the overall condition of the asset. The objective is optimal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B. NEED AND OUTCOME

Investment Need

Wood poles elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. These structures have various designs, sizes and configurations and support transmission circuits from 115 kV to 230 kV. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access.

Hydro One Transmission currently owns and manages approximately 42,000 wood pole structures spanning about 7,000 kilometers. As presented in Table 1 below, the average age of the wood pole fleet is currently 41 years and 34% of the wood poles are beyond their expected service life of 50 years.

Table 1 - Wood Pole Structure Demographics

Wood Structure	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Total	42,000	41	50	14,400	15,100	17,940

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood poles are deemed to be End of Life when the surface condition degrades and the poles are no longer climbable; there is significant surface and pole top rot; or where wood pecker holes have weakened the strength of the pole. Poles that are drilled and have 2.5 inches or less of solid circumferential wood remaining from internal rot will be replaced as they have fallen below their required design strength. All wood poles and components

TAB 3

Furthermore, the ISOC necessitated new land acquisition and telecommunication infrastructure.

c) The OEB approves funding at a macro level not at the project level and when the approval is less than what Hydro One requests, Hydro One reviews and optimizes the funding across the projects based on risk mitigation, customer commitments and other considerations. Funds are reallocated and reinvested; there are no reductions to the rate base. Details of the investment planning and redirection processes are included in Exhibit B, Tab 1, Schedule 1, Section 2.1.

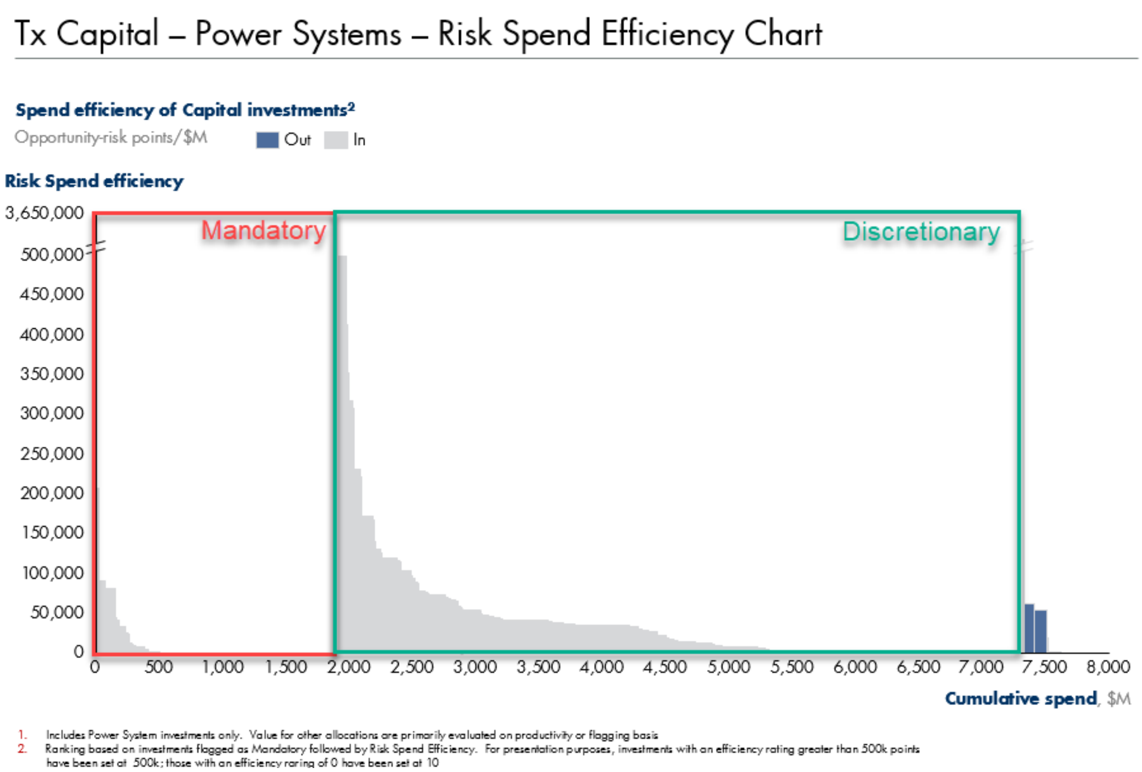
TAB 4

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:



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

- **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.

Table 2 - Line Refurbishment Projects Driven by EOL ACSR Conductors

Project	Circuit km of Project during planning period
B5/6C, BurlingtonTS X WestoverCTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
D2L, Upper Notch JCT X Martin River JCT, Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
E1C, Ear Falls TS X Slate Falls DS + Etruscan JCT X Crow River DS, Line Refurb.	162
H1L/H3L/H6LC/H8LC, Bloor Street JCT X Leaside 34 JCT, Line Refurb.	8
D6, Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT, Line Refurb.	77

Table 3 - Line Refurbishment Projects Driven by Obsolete Copper Conductors

Project	Circuit km of Project during planning period
D3A, Allanburg TS X AWS Steel CTS, Tx Line Refurb.	0 (project in-execution, majority replaced prior to 2020)
B3/B4, Horning Mountain JCT X Glanford JCT, Tx Line Refurb.	22
A8K/A9K, Str. 141 JCT X Kirkland Lake TS, Tx Line Refurb.	112
A7L/R1LB & 57M1, Alexander B JCT X Lakehead TS & Nipigon JCT, Tx Line Refurb.	227
K1/K2, Kirkland Lake TS X Holloway Holt JCT, Tx Line Refurb.	14
D2/3H & D4 & D6T, Hunta SS X Abitibi Canyon SS, Tx Line Refurb.	183
Q2AH, Rosedene JCT X St.Anns JCT, Tx Line Refurb.	22

To better serve our customers in Hamilton and THE surrounding area, we are planning to refurbish the existing 115 kilovolt (kV) line between Horning Mountain Junction (JCT) and Glanford JCT.

This transmission line, installed in 1915, is critical to serving electricity customers in the City of Hamilton. It is approaching its end-of-life and has been identified for replacement. The planned line refurbishment work is essential to ensure a safe and reliable electricity supply into the future.

The Horning Mountain JCT to Glanford JCT line refurbishment consists of two scopes of work:

1. Building a bypass line on the existing transmission circuit to ensure continued power to customers during construction. This will involve installing new equipment and wires on existing towers and installing approximately 20 temporary wood pole structures to accommodate the bypass line.

2. Replacing and relocating approximately 33 lattice towers with new steel monopole structures, lattice towers and new components to ensure infrastructure is aligned within the existing corridor. Work will also include reinforcing the remaining towers within the corridor.

Project Profile

This project involves refurbishing the existing 115 kV transmission line between Horning Mountain Junction to Glanford Junction. View maps of the study areas below.

https://www.hydroone.com/about/corporate-information/major-projects/horning-mountain supply industrial customers on radial (single supply) feeds. Hydro One will maintain the rate of replacement to mitigate safety and reliability risk.

- Steel Structure – poor condition steel structures that are eligible for coating will be coated proactively at a pace aligning with the OEB's Decision and Order in proceeding EB-2016-0160.
- Insulator – the proposed rate of replacement focuses on public safety, by addressing insulators in critical locations first (road crossings etc.) followed by non-publicly accessible areas.

Table 3 - Asset Replacement Rates - Transmission Station Assets

	Historical				Bridge	Test			Plan	
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Transformer Portfolio										
# of Replacements	21	19	15	26	20	9	23	19	40	17
% of Fleet	2.9%	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	148	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	184	453	465	370	503	681	384
% of Fleet	3.6%	5.1%	2.5%	1.5%	3.6%	3.7%	3.0%	4.0%	5.4%	3.1%

Table 4 - 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	850	850	745	560	800	800	800	800	800
% of Fleet	2.0%	2.0%	2.0%	1.8%	1.3%	1.9%	1.9%	1.9%	1.9%	1.9%

	Historical				Bridge	Test			Plan	
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Steel Structure Portfolio										
# of Renewal	300	462	725	1050	220	260	500	500	500	500
% of Fleet	0.6%	0.9%	1.4%	2.0%	0.4%	0.5%	1.0%	1.0%	1.0%	1.0%
Insulator Portfolio										
# of circuit structures	155	2100	3422	3900	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	0	0	0	4.7	0	0	0	0	7.2
% of Fleet	0%	0%	0%	0%	1.8%	0%	0%	0%	0%	2.7%

TAB 5

UNDERTAKING - JT 1.14

Reference:
I-07-SEC-046

Undertaking:
To provide the 2018 NATF transmission reliability report.

Response:
The 2018 NATF transmission reliability report was made available on October 10, 2019. Below please find a summary of the data.

The 2018 NATF Report replaced the IPII with TRIND (Transmission Index) due to the retirement of the IPII metric. TRIND, similar to IPII, is an index that aggregates key indicators to provide an overall score enabling the comparison of performance over time. Unlike IPII which was a single year score, TRIND provides a score reflecting a 5-year period.

There are nineteen peers in the 2018 data set.[1] Hydro One's ranking is shown below. Hydro One is investigating the factors contributing to the downward performance trend; one possible reason is the inclusion of 115 kV circuit data beginning in 2016. Prior to 2016 only 230 kV and 500 kV data was considered.

TRIND Total 5-year Period	Score*
2014-2018	19/19
2013-2017	17/21
2012-2016	13/21

**Lower score indicates better relative ranking*

The 2018 NATF Report included traditional metrics rankings for both 2018 on a stand-alone basis and for the 2014-2018 5-year period. These metrics are comparable to the traditional metrics in I-7-SEC-46.

[1] One peer didn't submit data and another only submitted partial data.

Traditional Reliability Metrics (200-799 kV) – Single and 5-year Average	**2018***	**2014-2018***
AC Circuit Outage Rate per Hundred Miles per Year	15/19	12/19
AC Circuit Outage Rate per Element per Year	19/19	17/19
AC Circuit Average Outage Rate Duration of Sustained Outages	14/19	13/19
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary	15/19	12/19
AC Circuit Outage Rate per Element per Year Rate-Momentary	18/19	16/19
AC Circuit Outage Rate per Hundred Miles per Year-Sustained	16/19	11/19
AC Circuit Outage Rate per Element per Year-Sustained	17/19	14/19

**Lower score indicates better relative ranking*

SEC INTERROGATORY #46

Reference:
D-02-01

Interrogatory:
Does Hydro One still participate in the NATF Transmission Reliability Reports, reliability assessments, or similar NATF initiatives? If so, please provide Hydro One's performance as compared to its peers for all years between to 2012 to 2018.

Response:
Yes. The 2018 report is expected to be released in September, 2019. The 2012 to 2017 data is provided in Attachment 1.

Hydro One Performance Ranking (7/21 means that Hydro One ranks 7th out of 21 peers, where 1st is the best performer)

IPII (Integrated Performance Indicator Index)	2017	2016	2015	2014	2013	2012
IPII Total Score	7/21	15/21	13/21	8/21	13/21	15/21
IPII Score Failed AC Circuit Equipment per Hundred Miles	8/21	9/21	16/21	11/21	11/21	12/21
IPII Score Failed AC Substation Equipment per Element	1/21	8/21	7/21	1/21	2/21	8/21
IPII Score Failed Protection System per Element	19/21	18/21	1/21	15/21	15/21	16/21
IPII Score Human Error per Element	8/21	7/21	1/21	1/21	9/21	11/21
IPII Score AC Circuit Unavailability per Element per Year	11/21	17/21	16/21	9/21	15/21	15/21
IPII Score AC Transformers Unavailability per Element per Year	11/21	15/21	14/21	12/21	10/21	10/21
IPII Score Unknowns per Hundred Miles	1/21	1/21	8/21	10/21	10/21	9/21
IPII Score Lightning per Hundred Miles	16/21	12/21	12/21	15/21	13/21	19/21
IPII Score Weather Excluding Lightning per Hundred Miles	13/21	10/21	7/21	8/21	10/21	6/21
IPII Score Aggregate Residual Causes per Hundred Miles	13/21	8/21	14/21	15/21	14/21	19/21

Traditional Metrics (single year)	2017	2016	2015	2014	2013	2012
AC Circuit Outage Rate per Hundred Miles per Year 200-799 kV	12/21	9/21	9/21	13/21	14/21	10/21
AC Circuit Outage Rate per Element per Year 200-799 kV	18/21	16/21	15/21	17/21	19/21	16/21
AC Circuit Average Outage Rate Duration of Sustained Outages 200-799 kV	10/21	20/21	17/21	7/21	13/21	12/21
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary 200-799 kV	16/21	11/21	9/21	15/21	17/21	14/21
AC Circuit Outage Rate per Element per Year Rate-Momentary 200-799 kV	19/21	14/21	14/21	17/21	20/21	17/21
AC Circuit Outage Rate per Hundred Miles per Year-Sustained 200-799 kV	7/21	8/21	10/21	14/21	15/21	7/21
AC Circuit Outage Rate per Element per Year-Sustained 200-799 kV	14/21	14/21	15/21	14/21	18/21	10/21

Traditional Metrics (five year average)	2013-17	2012-16	2011-15	2010-14	2009-13	2008-12
AC Circuit Outage Rate per Hundred Miles per Year 200-799 kV	14/21	13/21	14/21	15/21	16/21	15/21
AC Circuit Outage Rate per Element per Year 200-799 kV	18/21	19/21	18/21	19/21	20/21	18/21
AC Circuit Average Outage Rate Duration of Sustained Outages 200-799 kV	10/21	13/21	10/21	10/21	11/21	9/21
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary 200-799 kV	15/21	14/21	15/21	17/21	18/21	18/21
AC Circuit Outage Rate per Element per Year Rate-Momentary 200-799 kV	17/21	17/21	18/21	18/21	18/21	18/21
AC Circuit Outage Rate per Hundred Miles per Year-Sustained 200-799 kV	11/21	12/21	11/21	11/21	10/21	9/21
AC Circuit Outage Rate per Element per Year-Sustained 200-799 kV	15/21	18/21	16/21	17/21	14/21	12/21

Over the plan period, Hydro One aims to improve against its historical average, targeting 0.45 for T-SAIFI-M.

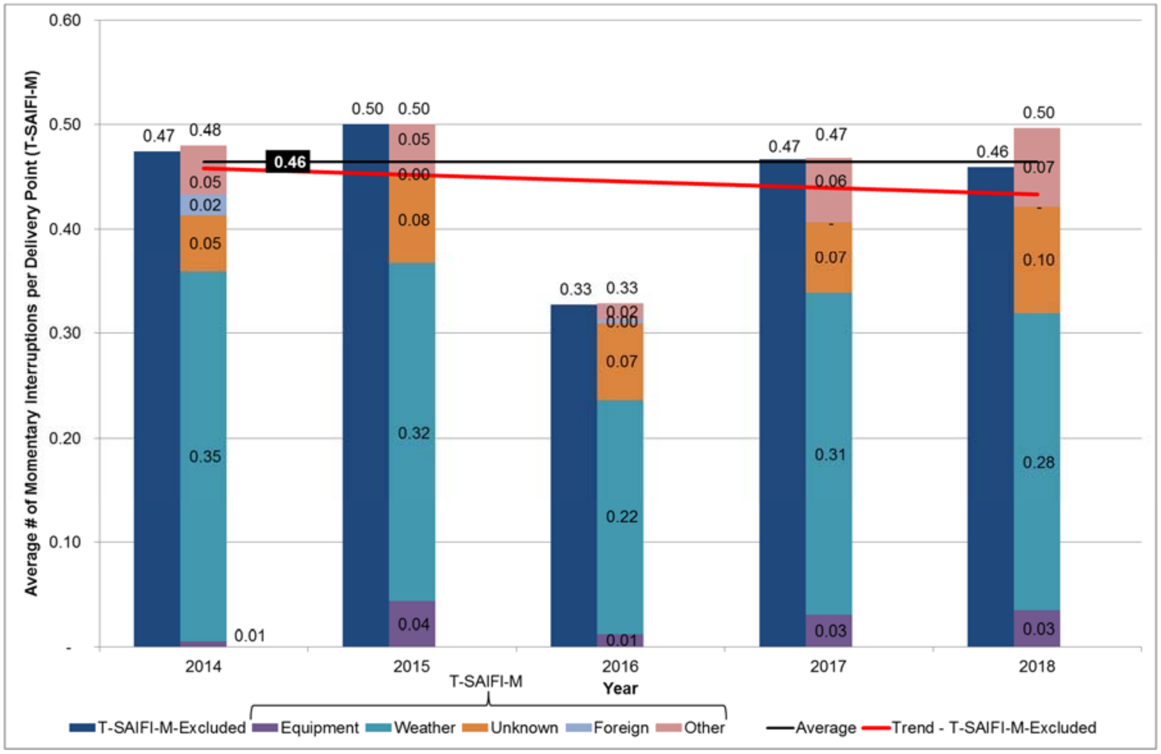


Figure 7 - Transmission System Average Interruption Frequency Index – Momentary Interruption

T-SAIDI is the average duration of sustained DP interruptions – those greater than one minute in duration – and is used as an indicator of the average minutes of unplanned interruptions that customers experience per DP in the year.

The average duration of sustained interruptions per DP in 2018 was 69.9 minutes, an increase of 27.1 minutes or about 63 per cent compared to 2017. The result in 2018 was driven by a large freezing rain event on April 14th, an extreme wind storm in southern Ontario on May 4, 2018, outages impacting eastern Toronto as a result of events in proximity to Hearn SS and Gerrard TS on Jan 8, 2018 and Feb 10, 2018 and the Finch TS T2 failure on July 27-28, 2018.

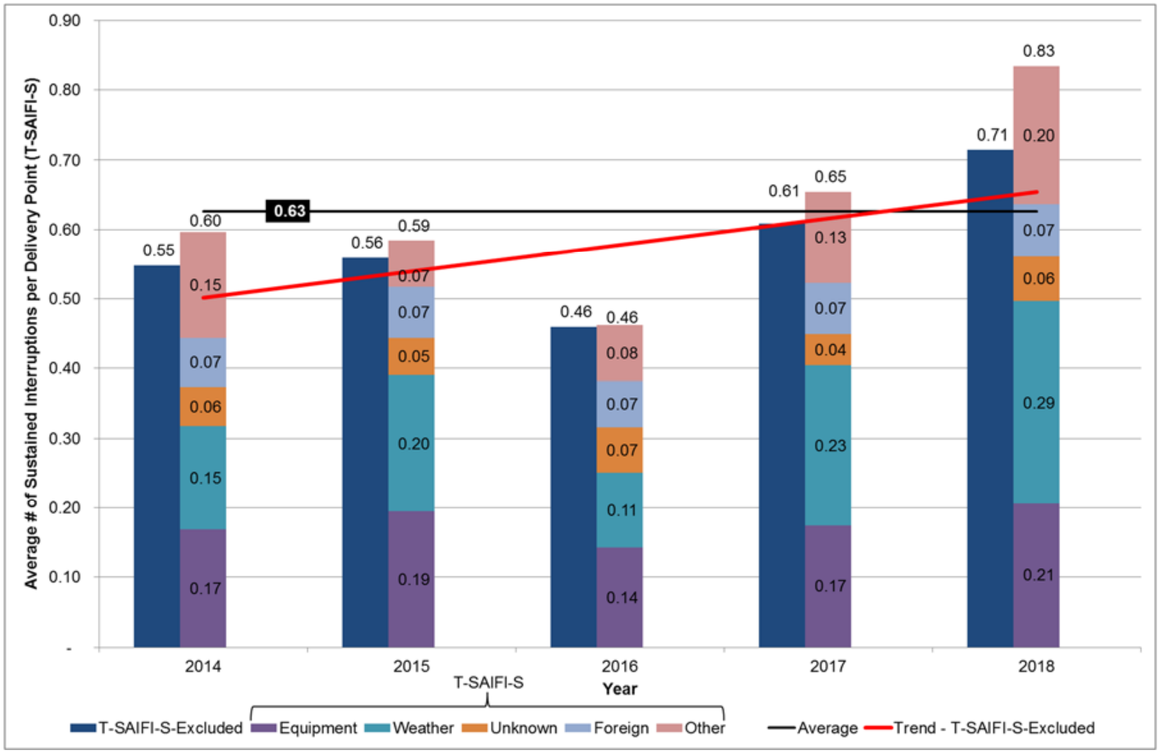


Figure 6 - Transmission System Average Interruption Frequency Index – Sustained Interruption

T-SAIFI-M is the average frequency of DP momentary interruptions – those less than one minute in duration – and is used as an indicator of the average number of unplanned momentary interruptions that customers experience per DP in the year.

The average number of momentary interruptions per DP in 2018 was 0.50, an increase in the index value of 0.03 or about 6 per cent compared to 2017, primarily due to more weather caused interruptions.

Hydro One's average performance over the past five years (2014-18) was 0.46 interruptions per DP, and the performance trend is relatively flat (see Figure 7).

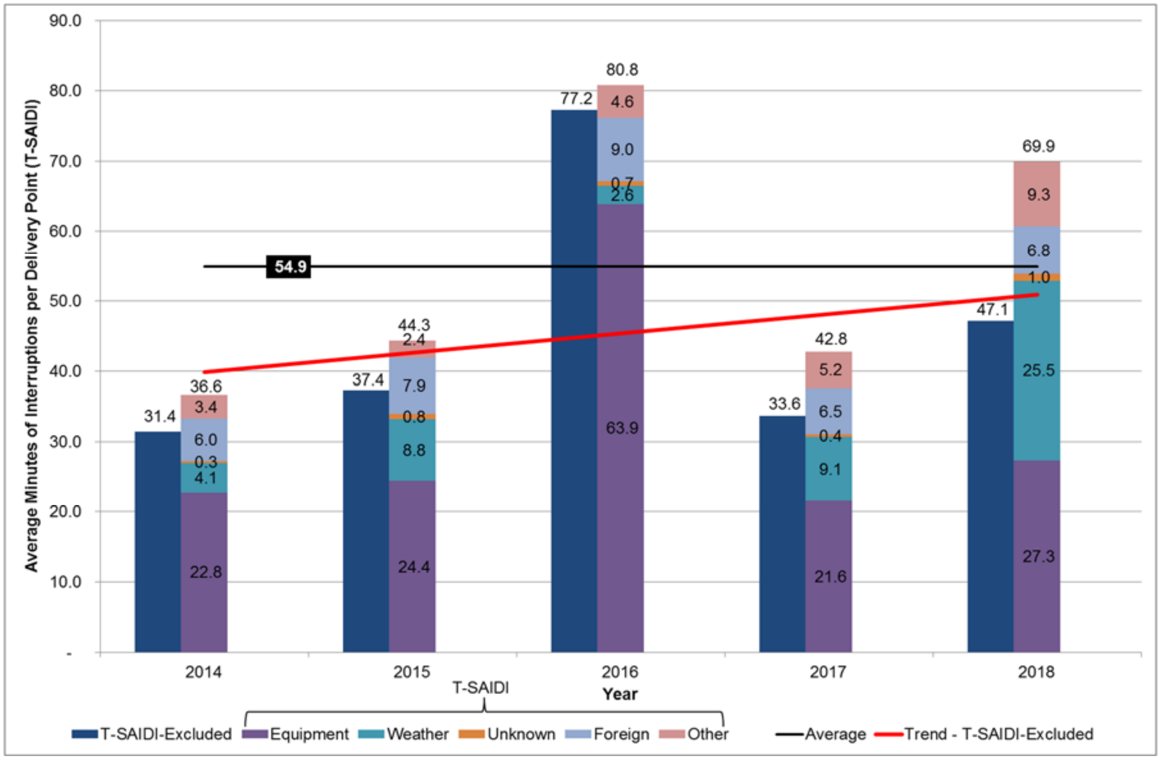


Figure 8 - Transmission System Average Interruption Duration Index (minutes)

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.

TAB 6

Performance Categories	Measures	2014	2015	2016	2017	2018	Targets 2019	2020	2021	2022	2023	2024
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
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	97	100	100	100	100	100	100
	OM&A Program Accomplishment (composite index)		97	99	108	107	100	100.0	100.0	100.0	100.0	100.0
	Capital Program Accomplishment (composite index)		122	59	88	120	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
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 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.

Ontario

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

DECISION AND ORDER

EB-2016-0160

HYDRO ONE NETWORKS INC.

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018

BEFORE: Ken Quesnelle
Vice Chair and Presiding Member

Emad Elsayed
Member

Peter C. P. Thompson, Q.C.
Member

September 28, 2017

performance management system of its distribution customers' satisfaction level for the purpose of gauging what, if any, elements of transmission operation are the cause of any dissatisfaction.

With respect to operational effectiveness, the OEB finds Hydro One's proposed Cost Control measures to be appropriate as the ratios proposed will provide meaningful measures of relative quantitative benchmarks that can be monitored over time. However, the measures proposed for asset management could potentially run counter to the cost control performance indicators. The asset management measures are directly linked to Hydro One's budget and "OEB-approved plan". It is important to note that the OEB does not approve capital plans, but rather a capital envelope which provides an input to the revenue requirement which in turn determines the approved rates. The capital plans that underpin the submitted revenue requirement in an application are intended to illustrate the need for the submitted revenue requirement on a prospective basis. In other words, the plan is provided to facilitate consideration of the reasonableness of the requested revenues.

In this Decision, the OEB has directed Hydro One to provide a report on the execution of its capital plan. The purpose of the report is to demonstrate that its planning process is robust and that it is capable of executing the plan. This report is to include rationale for any departure from the plan. Such rationale may include awareness that the plan is no longer considered economical. This awareness would be based on previously unknown situations, solutions or more generally, a change in the main drivers for the original plan. In other words, it becomes apparent that the execution of particular elements of the plan is no longer in the interest of the customer. The proposed scorecard does not encompass the potential for this eventuality and to the extent that this performance indicator drives employee compensation it has the potential to suppress the desired ongoing evaluation of the prospective plan. As the OEB has determined in this Decision, plan execution is important but it should not be driven by a performance indicator solely based on ensuring the level of spending originally considered reasonable is spent.

Asset management is at the core of Hydro One's business function. The OEB expects Hydro One to consider implementing broader Asset Management measures that are directly related to positive outcomes for its customers. For instance, performance measures related to improvements in Hydro One's asset diagnostics that enhance the accuracy of asset replacement schedules could result in direct benefits to customers.

With respect to Policy Response, the OEB does not consider Hydro One's proposed inclusion of North American Electricity Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) Standards to be aligned with the intent of this

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.

TAB 7

VECC INTERROGATORY #14

Reference:
D-02-01-01p. 3

Interrogatory:

a) Please explain the rationale for different customer delivery point performance standards based on load size. If the response relies on requirements in the Transmission System Code, please provide those requirements.

b) The proposed standards are based on data which is between 28 and 19 years old. Please explain why standards based on this aged data remain relevant to current performance of delivery points in Ontario.

c) Please explain the impediments to updating the standards based on 2000-2018 data.

d) Please explain for each of the past 5 years (2019 inclusive) how many "technical and financial evaluations were done in consultation with affected customers" due to point performance failing below the minimum CDPP.

Response:

a) When the standards were developed, the rational for different customer delivery point performance standards based on load size was provided in the following Board document: RP-1999-0057, EB-2002-0424. Following is a copy of the related materials from the document.

2.3.1 Load Grouping for Group (Outlier) CDPP Standards – General

Hydro One has proposed to apply different performance standards depending on the size of total average station load being served. For this purpose, load would be classified in one of four load bands (0-15 MW, 15-40 MW, 40-80 MW and >80 MW).

Hydro One took the position that the use of load bands accommodates normal year-to-year delivery point performance variations, limits the number of delivery points that are to be considered "performance outliers" to a manageable level, is commensurate with customer value ("the bigger the load the greater the level of reliability"), and will allow, or direct, focus on reliability improvements at the "worst" performing delivery points.

As evidence of the reasonableness of the methodology of basing performance standard on load size, Hydro One pointed to the Independent Electricity System Operator's ("IESO") Supply Deliverability Guidelines. Those Guidelines, which apply to preconnection studies for transmission customer connections, contain as a basic premise that the level of reliability of supply should be related to the size of the load being served, i.e., the larger the load, the greater the level of reliability. Similarly, in general the greater the load affected, the shorter the duration of the interruption is desired. The Guidelines also refer to the former Ontario Hydro's Guide to Planning Regional Supply System Deliverability (also known as the "E2" Guide). That Guide reflects a similar approach by using groupings according to load size for purposes of establishing the maximum acceptable severity of interruption.

Hydro One also submitted a survey of customer interruption costs ("CIC"), which represent the economic value to customers of unsupplied MWh of energy. The survey indicated that, for a given duration of interruption, the CICs increase as the size of the load increases. Hydro One then calculated a "Customer Value of Reliability" based on the number of interruptions that would result in different levels of CICs being achieved, up to a "CIC Ceiling" equal to Hydro One's annual transformation and line connection costs for a 15 MW load.

The Board considers that the use of a grouping methodology for performance standard purposes strikes the right balance with respect to practical application and accuracy. The Board finds that Hydro One's approach, based on a measure of the customer's value of reliability which varies with the size of the load served, is reasonable. Although Hydro One is not able to estimate the value that one megawatt represents to each customer in terms of some common quality, such as profit or productivity, the Board finds that the CIC concept is not unreasonable as a proxy.

b) Ontario transmission system was well developed in 70s and 80s. The system had relatively good reliability performance in 90 due to stable equipment performance. The overall system T-SAIDI performance in this period is better than that from 2000s or 2010s, where aging equipment failure is a main contributor to the later.

c) It is possible to update the standards based on 2000-2018 data, however, there will be no impact to customers as a result of doing so.

d) Over the last five years Customer Delivery Points below the minimum CDPP triggered have been between 84 - 105. Hydro One has completed assessments of all of these 84 DPs for 2017 which are determined based on the three year performance history. 2018 analysis is expected to be completed by Q1 2020. Hydro One consults with its customer on a regular basis, such as planning and operating meeting or different stages of ongoing sustainment programs and projects. In most cases, mitigation measures are part of Hydro One sustainment planning and assessments for safe, secure and reliable operation. Hydro One undertakes customer specific consultation for performance failing below the minimum CDPP if and when a) mitigation results in any changes to system configuration affecting customer(s) and b) a customer contribution is required to implement mitigation.

VECC INTERROGATORY #15

Reference:
D-02-01-01

Interrogatory:

a) In the above noted section is an explanation as to the attribution of costs for delivery point reliability improvements. Please clarify – if a delivery points falls below the CDPP standard can the affected customer(s) be required to financially contribute to improvements to bring the delivery point to its respective CDPP standard. If this is correct please explain the rationale for customer contribution to maintain a station at its CDPP standard.

Response:

a) Correct. Where the three-year rolling average of the delivery point performance falls below the minimum Group CDPP Standard, Hydro One's level of incremental investment to improve the group outlier's reliability performance will be limited to the present value of three years' worth of transformation and/or transmission line connection revenue associated with the delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by the affected delivery point customers. Hydro One is of the view that this sharing of costs between the affected customers and ratepayers is necessary to strike a balance that encourages proceeding with only those reliability performance improvements that are technically and economically practical and to limit the subsidization of reliability improvement costs by other pool customers.

TAB 8

Figure 4 - Fallen span of conductor

Figure 5 - Damage from a fallen conductor