Hydro One Networks Inc.

EB-2019-0082

OEB Staff Compendium

Capital Expenditures and Transmission System Plan Issues

Panel 1

October 22, 2019

2
DESCRIPTION OF THE DATA

Introduction

Data Sets

Conductor data was organized into two principal sets:

1) Conductor condition assessment data. This data was provided in two data sets:

    a) The first condition assessment data set (referred to hereafter as data set 1a) was from an earlier study conducted by Hydro One, i.e. Conductor End of Life Study dated August 2016. This set was used to perform exploratory data analyses as documented in Chapter 3.

    b) The second condition assessment data set (referred to hereafter as data set 1b) was provided at a later date and consists of additional OCS 4 data as well as additional samples from "Long Test Reports". This set was used to derive condition assessment based Weibull models as documented in Chapter 4.

2) Replacements and in-service fleet demographic data. The replacement data was used to derive the replacement-based Weibull model as documented in Chapter 4. The in-service fleet demographic data was used as the basis for calculating projections of circuit-kilometers that will reach conditions that require replacements in the future, as documented in Chapter 5.

The remainder of this chapter provides a more detailed description of the above mentioned data sets. Note that the following section on conductor assessment data focuses on data set 1b as this is the data used to derive the condition-based hazard functions.

Conductor Assessment Data

The conductor assessment data set (1b) comprises 443 records extracted from test reports dated from 2001 to 2016, with one assessment performed per conductor. Of the 443 records, 420 records applied to aluminum conductor steel reinforced (ACSR) samples, therefore the analysis focused on ACSR conductors. Other conductor types may perform differently.

The assessment data provided for each conductor included (1) demographic description such as age, size and stranding, and (2) condition assessment including extent of rust, severity of rust, remaining zinc, torsional ductility, and tensile strength. From this data, the project team explored how the conductor overall condition and its constituent assessment factors are affected by independent variables including age, conductor stranding, conductor size, and corrosion zone categorization.

General Discussion

The conductor Condition Assessment (Score) data used are not from random samples.

For the replacements data, it is unclear whether all replacements were due to failures or lines reaching condition(s) that warrant replacements or some other reasons. Analysis results from such data can potentially be pessimistic. However, the similarity between results based on condition assessment data and results based on replacements data lead one to believe that such a concern is not necessarily warranted, especially when the commonalities between the two data sources in terms of time periods and circuits represented are limited (as discussed previously and shown in Figure 4-3).

both OCS 5 and OCS 4, and five circuits are represented by both OCS 5 (long) and OCS 4. Among these intersections, three circuits (C27P, D2L) are represented by all three subsets.

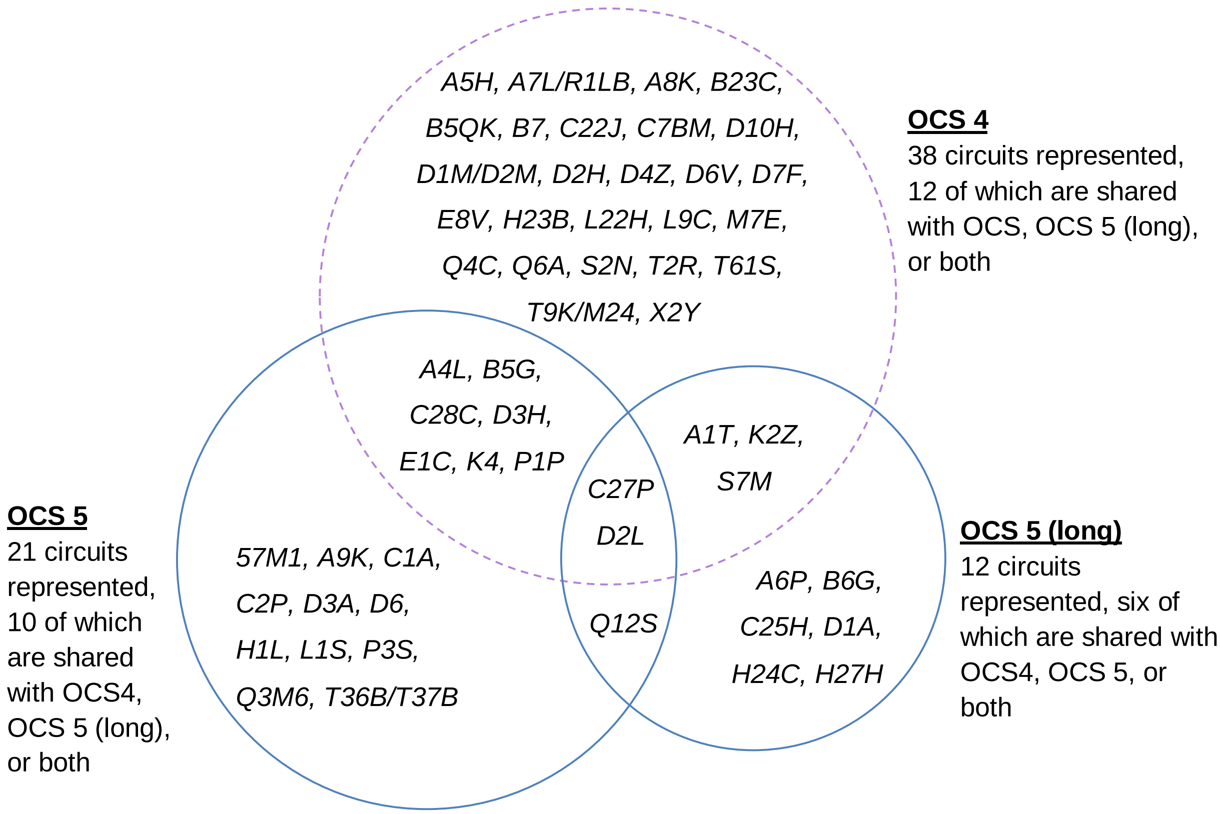


Figure 2-1
Venn Diagram Showing Circuits Associated with All Three Subsets of the Conductor Assessment Data, i.e. OCS 5, OCS 5 (long), and OCS 4, along with their Intersections

Replacements and In-Service Fleet Demographic Data

In addition to the assessment data, Hydro One provided historical replacement records. These replacement records span from January 1988 to January 2017 and the youngest age at replacement recorded was 41. A total of 126 replacement records were provided for 48 unique circuit designations and totaled 3,858 kilometers. Also provided was a list of in-service line sections and their ages representing 559 unique circuit designations. Figure 2-2 shows the cumulative installed conductor length by age, based on in-service ACSR fleet data as of October 2017.

possible.

MR. KEIZER: That's fine.

MR. SIDLOFSKY: So that will be JT1.1.

MR. WALSH: Next question is on 77, thank you. So I'd understood that in Hydro One's response it is not possible to refurbish or maintain deteriorated conductor through repairs.

If Hydro One were to replace a deteriorated splicer sleeve, is this considered to be a repair to the conductor system or the conductor?

MS. JABLONSKY: It would be considered a repair.

MR. WALSH: A repair to the conductor?

MS. JABLONSKY: To the conductor. It is a component.

MR. WALSH: Okay. So if you had the repair would it change the condition assessment for the conductor?

MS. JABLONSKY: If that was the only component that was deteriorated. But if we are looking at the ESL for the conductor, it is far greater than the ESL of the sub-component of the conductor.

MR. WALSH: Okay, thank you. So in response to Staff 118, Hydro One stated that conductor-caused outages are tracked at the conductor system level and not at the conductor sub-components level. That's my understanding.

How does Hydro One differentiate between an outage caused by -- or caused by deteriorated or improperly installed splice or sleeve or connector on a conductor and an outage caused by a deterioration of the actual conductor?

MR. JESUS: We don't differentiate. If a conductor fails we treat it as a failure of the conductor.

MR. WALSH: Okay. Thank you. In Staff 119(b) you stated that replacing a splice costs approximately 1/20th as much as replacing the conductor section between splices. Given the significant cost differential between replacing splices and replacing entire conductor systems, would it be prudent for Hydro One to track conductor system failure causes to validate whether conductor failure risk is primarily attributable to splice failures or to general conductor failures?

MR. JESUS: I think -- I think we need to recognize that a conductor is -- we take samples in sections of the conductor. So although it's failed in a small section, it has not addressed the overall condition of that conductor.

So, yes, a splice if it fails would be used to quickly restore supply to our customers, but the overall condition of that conductor has not changed. So we will -- we take samples of our sections. We don't normally go in there and say there's a 200-kilometre line and replace the whole thing. We look at the appropriate sections where we carry out condition maintenance and condition assessments of various sections and we determine whether or not the entire conductor needs to be replaced. Splicing is just a temporary fix, and it has not addressed the overall deterioration of that steel that's in the air.

MR. WALSH: Okay, thank you. Is loss of tensile strength and loss of ductility for typical Hydro One

OEB INTERROGATORY #119

Reference:

TSP-03-03, ISD-SR-19

Interrogatory:

a) Please confirm that the example in Figure 5 shows a failed splice rather than a failed conductor.

b) Please compare the relative cost of replacing a sleeve or dead end fitting versus the cost of replacing 3 to 4 km of conductor (i.e. the distance between splices for typical reel lengths).

c) Does Hydro One preferentially replace entire reels of conductor in situations where the conductor system deterioration is focused at sleeves and/or dead end fittings?

Response:

a) As stated in ISD SR-19, page 7, Figure 5 shows a fallen conductor as a result of an insulator failure.

b) The cost of replacing a single conductor connector is approximately 1/20th of the cost of replacing 3 to 4 km of conductor.

c) Hydro One does not preferentially replace entire reels of conductor in situations where a conductor system's deterioration is verified to be isolated to a conductor connector.

Witness: Donna Jablonsky

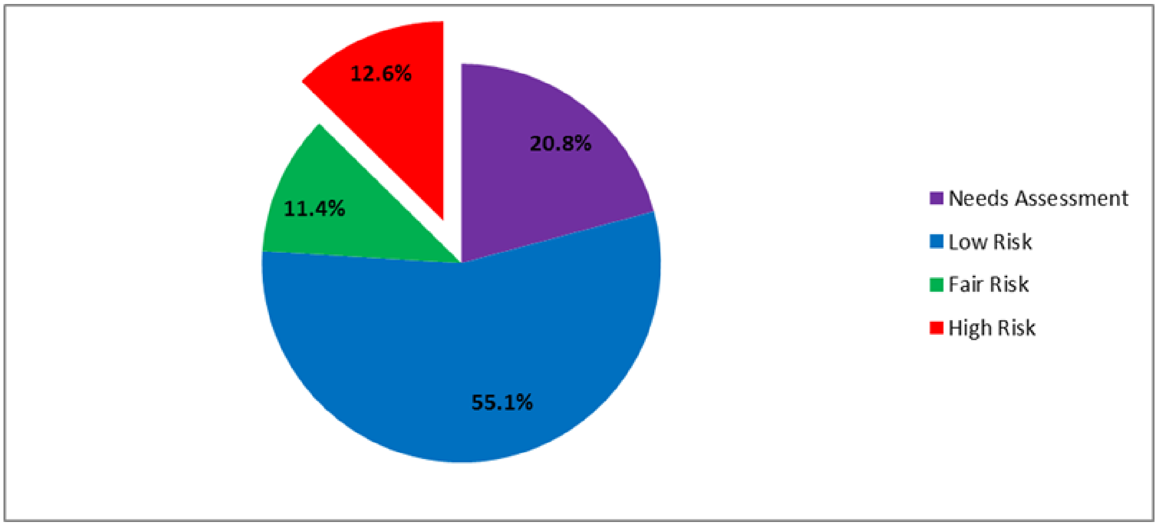


Figure 1 - Distribution of Overhead Conductor Condition

ACSR conductors consist of aluminum strands that surround galvanized steel strands, referred to as the core. Once the galvanized coating of the core wears off, for example as a result of weather or strand movement, the exposed steel strands corrode quickly, resulting in a loss of tensile strength or ductility. Deterioration of tensile strength results in a failure to hold required loads, while deterioration in ductility, makes the conductor brittle, making the suspended conductor which is moved by wind forces susceptible to cracking and breaking, as shown in Figure 2.

Figure 2 - Broken ACSR Conductor

Figure 4 - Fallen span of conductor

Figure 5 - Damage from a fallen conductor

Condition Assessment Methodology

The following describes the parameters considered by Hydro One when performing condition assessment on ACSR conductors. These condition parameters are derived through 3rd party laboratory testing on conductor samples typically five meters in length. These five condition parameters are:

1) Extent of Rust – Visual Inspection
2) Severity of Rust – Visual Inspection
3) Remaining Zinc – ASTM test
4) Torsional Ductility – ASTM test
5) Tensile Strength – ASTM test

Based on the test results, a 1 to 5 (best to worst) condition value was assigned for each test. Strand tests were translated to overall conductor state. Conductor overall condition is expressed as a weighted average, as shown in Table 2-1.

Table 2-1
Overall Conductor Condition: Weighted Average
(Source: *Hydro One Conductor Condition Assessment Program)*

Assessment (Test) Factor	Weight for Overall Condition
Extent of Rust	10%
Severity of Rust	10%
Remaining Zinc	10%
Torsional Ductility	30%
Tensile Strength	40%
Total	100%

Conductor Condition Assessment Data

The Hydro One Conductor Condition Assessment Program defines an overall condition score of 5 as equivalent to "end-of-life." Hydro One provided condition assessment data collected between January 2001 and December 2016.

Investigators separated conductor assessment data by Overall Condition Score (OCS). Of the initial 404 conductor samples, 28 samples were assessed as OCS 5 from 21 different circuits and 61 samples were assessed as OCS 4 from an additional 29 different circuits. The remaining 315 samples were assessed as OCS 1 through 3.

Hydro One provided an additional set of 16 ACSR condition assessments based on "Long Test Reports" for 12 unique circuits. These were reports of more extensive laboratory investigations of this added set of field samples. All of these samples were considered as OCS 5 providing another 9 different circuits not assessed as OCS 5 in the previous data set.

Considering all the available assessment data, samples from a total of 30 unique circuits were deemed to have an OCS of 5. Figure 2-1 illustrates the circuits that are represented by all three subsets of the conductor assessment data, namely OCS 5, OCS 5 (long), and OCS 4. Note that three circuits are represented by both OCS 5 and OCS 5 (long). Nine circuits are represented by

e) As discussed in Exhibit B-1-1, TSP 2.2, the number of forced outages due to conductor failures has improved over the past ten years while the outage duration has been relatively stable over the same period. However, Hydro One aims to proactively replace its deteriorated assets before they fail. As such, meaningful correlation between failure rates and fleet/system condition is not available. As noted in Interrogatory I-01-OEB-120 part e) i) and discussed in See I-01-OEB-125, between 2008 and 2018, 36 delivery points were interrupted as a result of failures along the 1903 circuit-km of ACSR conductor planned for replacement. This corresponds to 0.02 delivery point interruptions per km. In comparison, the overall fleet of 29,107 circuit-km of conductor experienced 126 delivery point interruptions between 2008 and 2018. This corresponds to 0.004 delivery point interruptions per km. Therefore, the 1903 circuit-km of conductor planned for refurbishment is presently demonstrating five times more delivery point interruption when compared to the overall fleet.

OEB INTERROGATORY #93

Reference:
TSP-03-01 p. 16 TSP-01-01 p. 43

Interrogatory:
At the first reference above, Hydro One stated the following:

Hydro One operates a condition assessment program that focuses on conductors beyond 50 years of age. Condition assessment results indicate that 13% of the conductor fleet is at high risk. Despite a planned increased level of replacements when compared to historical levels, the number of conductors beyond the ESL of 90 years is still increasing. An overhead conductor failure can have severe reliability and safety consequences. If this issue is not addressed in a proactive and timely manner, system and customer reliability as well as safety will be placed at risk. Consequently, an increase in planned replacements – even though it will not completely stop or reverse the trend in line demographics – is required to maintain acceptable fleet condition and performance and to avoid a sudden spike in future investments that would otherwise be required as a result of deferred replacements.

At the second reference above, Hydro One stated the following:

Lines Asset Management
Hydro One's approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. In particular, transmission conductors have an expected service life of 90 years. When a conductor fails or based on its condition, as confirmed by testing, has been determined to have reached end of life, replacement is the only solution.

a) How common are system events caused by overhead conductor failures? To be more specific, what percentage of Hydro One customer delivery point interruptions are directly caused by spontaneous condition-related conductor failures?

b) How many such events occur each year?

Witness: Bruno Jesus, Donna Jablonsky

c) Please confirm that the stated percentages and event counts in Hydro One's response to parts a) and b) do not include conductor failures caused by external factors such as tree falls, vehicle contacts, lightning strikes, tornadoes/extreme wind fronts or extreme snow/ice loads that exceed design loads.

d) Please provide a list of the most common conductor-related failure modes experienced by Hydro One (e.g. sagging into objects during hot weather power loads, heavy snow loads or heavy ice loads, blowing into other objects under extreme wind loads, phase to phase contacts under galloping conditions, splice/sleeve failures, dead end/termination compression hardware failures, etc.).

e) Please provide an associated percentage of conductor failures per mode identified in part d).

f) Please distinguish between conductor life and risk of failure versus sleeve (splice) or compression dead end failure.

Response:

a) Approximately 1% of delivery point interruptions are due to conductor failure.

b) There are on average 9 delivery point interruptions per year.

c) The interruptions are related to conductor failure. The mechanism of failure is not readily available.

d) There are two major modes of failure with transmission conductors – loss of tensile strength and loss of ductility. Isolated deficiencies such as surface corrosion bird-caging, strand fraying or splice disconnects can be repaired and are not considered failure modes for the conductor system.

e) Statistics on conductor modes of failure are not readily available.

f) This differentiation is not available. As presented in Exhibit B-1-1, TSP Section 2.2, page 58, conductor caused outages are tracked at the conductor system level as a whole and not down to individual conductor components.

look at these projects first for reprioritization. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

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**	**1,109.2**	**1,181.1**	**1,181.5**	**1,194.9**
Less Capital Contributions ($M)		*(3.8)*	*(6.1)*	*(8.3)*	*(4.1)*	*(1.1)*
Total Net System Renewal Capital ($M)		**865.2**	**1,103.1**	**1,172.8**	**1,177.4**	**1,193.8**

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

UNDERTAKING - JT 1.11

Reference:
I-07-SEC-016, part c)

Undertaking:
To re-file previous undertakings, now un-redacting the previously redacted transmission related information.

Response:
Attachments 1 to 8 contain Hydro One's response to the undertakings J2.4 and J7.01 that were filed in the EB-2017-0049 proceeding. These attachments are also referenced in the interrogatory response, I-07-SEC-016 filed in the current proceeding. Certain portions of the attachments contain information that has been redacted with a red box or a black box as follows:

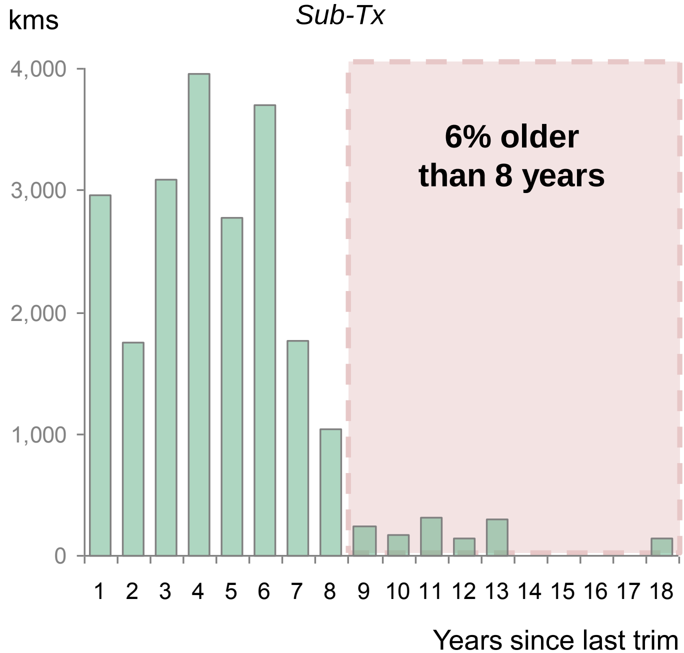
- Red box redactions contain information that relates to the unregulated business of Hydro One's affiliated companies and as such is not relevant and falls outside of the scope of the current proceeding. In the EB-2017-0049 proceeding, the Board considered the relevance of the red box redacted information and concluded that it has little probative value to the Board in assessing the ultimate proposal submitted by Hydro One in its application.

- Black box redactions contain information that was prepared in contemplation of Hydro One's 2017-2018 transmission rate application (EB-2016-0160). In most instances, the information contains plans, strategies, or considerations that were formulated in developing the 2017-2018 transmission rate application. It also contains historical information and values that have been reproduced in the current proceeding. The EB-2016-0160 proceeding has been adjudicated and the Board rendered its revised decision on November 1, 2017. As such, the information pertaining to the concluded proceeding is not relevant and has no probative value to the Board in assessing Hydro One's proposals that are subject of the current proceeding.

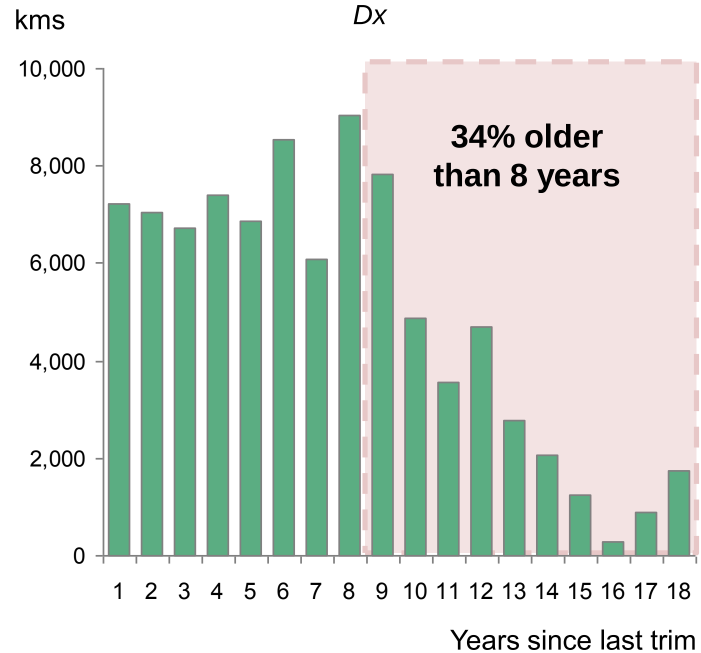
4 Clear backlog

Sub-Tx lines have been maintained on a 6-8 year cycle at the expense of Dx lines

Nearly all Sub-Tx lines have been maintained on 6-8 year cycle



Over one third of Dx feeders older than 8 years old



Current vegetation management spending insufficient to maintain all ROW on <8 year cycle

Source: Hydro One Asset Portfolio Document: Right-of-Way Management

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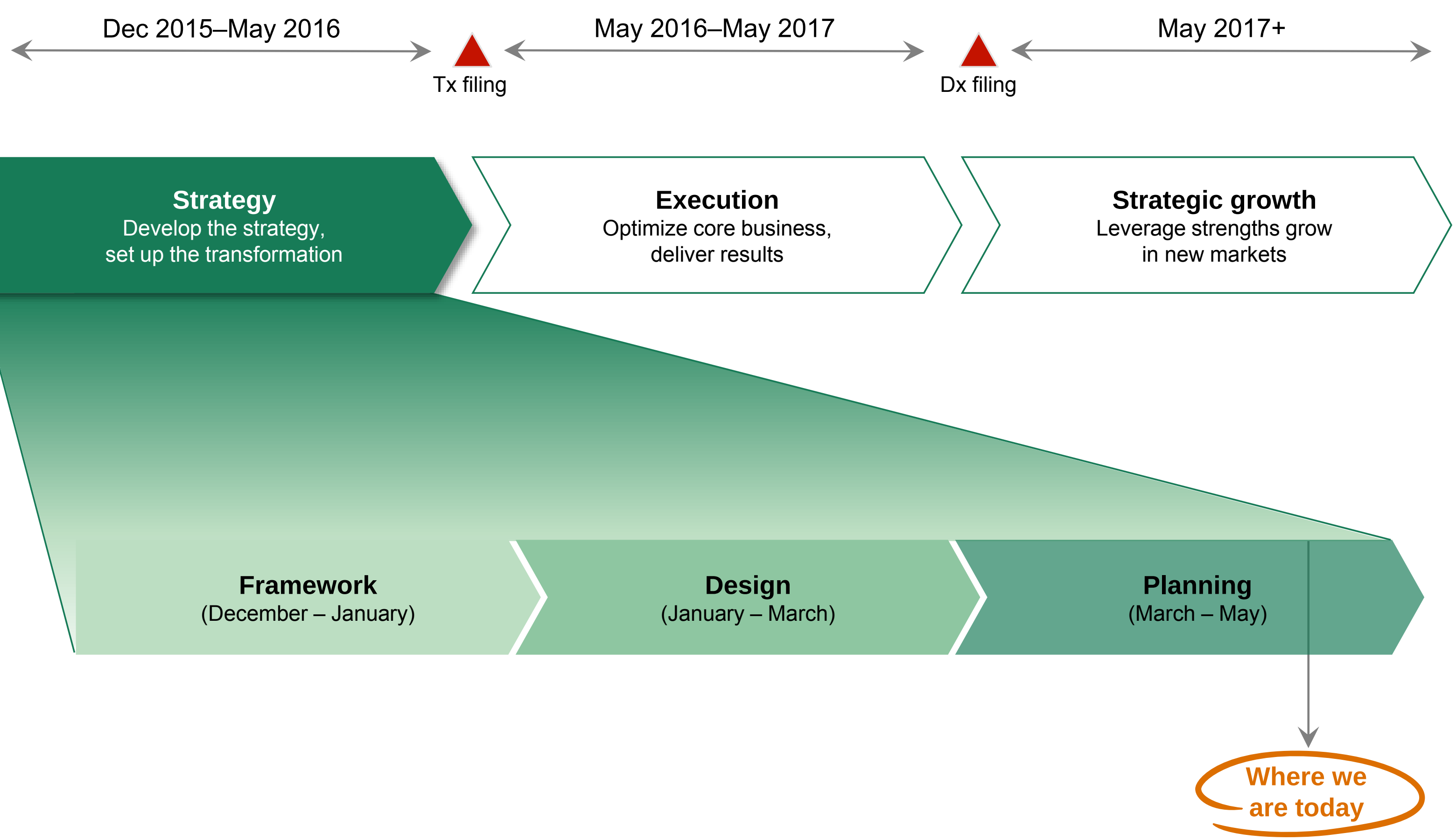
Context: Where we are in the longer-term journey

Completing Planning in preparation for Execution



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Overall strategic narrative (I)

Since privatization, Hydro One has embarked on a journey to becoming a best-in-class, customer-centric commercial organization. This is consistent with the 4 core principles of the RRFE[1]

- Customer focus: Responding to the needs and preferences of customers
- Operational effectiveness: Meeting reliability and quality objectives while continuously driving productivity
- Public policy responsiveness: Delivering on obligations mandated by government
- Financial performance: Maintaining financial viability, sustaining operational effectiveness efforts

Our strategy translates these principles into our approach to

- Serving our customers
- Forming our investment plans (for approval in rate filings)
- Operating and managing the costs of our business

…while maintaining our strong commitment to Safety and the Environment

Serving our customers: Improving the end-to-end customer experience and satisfaction by addressing the unique needs of our four core segments. In the near-term we will focus on:

- Residential/Small Business: Improving first-call resolution, enhancing digital experience, redesigning the bill
- Commercial & Industrial: Marketing energy conservation programs, improving first-call resolution
- Large Distribution: Marketing energy conservation programs, better communicating unplanned outages
- Transmission: Pro-active reporting on power quality and reliability, following through on commitments made

1. Renewed Regulatory Framework for Electricity

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Overall strategic narrative (II)

Forming investment plans: Be responsible stewards of assets while taking a customer-centric approach

- Transmission: Sustain assets to meet reliability, risk, and power quality needs of customers
- Distribution: Transition to a modern, reliable grid through condition-based asset renewal and targeted enhancement programs to increase reliability and functionality with highest return on investment

Investment plans will be presented in 3 rate filings, each with unique objectives to consider:

- 2-year Transmission filing (May 2016):
  - Signal longer-term capital plan (5 year plan weighted to out-years, based on risk modeling)
  - Shift to RRFE[1] principles (e.g. consult with customers, incorporate productivity commitment)
- 5-year Distribution filing (May 2017):
  - Assess range of investment options through customer consultation
  - Align on incentive rate structure based on capital flexibility and fair distribution of productivity incentives
- 5-year Transmission filing (May 2018):
  - Secure investment plan previewed in May 2016 submission and replicate
  - Replicate incentive rate structure established in Distribution the prior year

Operating and managing the costs of our business: Set efficiency targets informed by benchmarks and track through a performance management system

- Efficiency program launched to both offset customer bill impacts and capture productivity benefits
- Unconstrained potential of ~$200M (~50/50 OM&A vs. capital) with varying degrees of difficulty to capture
- Execution already underway to build early momentum and drive impact near-term

1. Renewed regulatory framework for electricity

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Overall strategic narrative (III)

Our strategy effectively balances shareholder returns and rate payer impacts over the next 5 years

- Total capital expected to grow to ~$2B+ by 2021, resulting in rate base of ~$22B (~5-6% growth)
- OM&A expected to remain flat to 2021, with cost pressures (e.g. inflation) offset by efficiency program impacts
- Range of scenarios possible, depending on investment plan approval and efficiency potential realized
- Implies [redacted] TSR and annual tariff increases of 2-3% for Distribution and 5-6% for Transmission

As we continue our transition to a high performing culture, we have identified 10 core capabilities to successfully deliver on this plan and prepare us for future growth

- Aspire to be best-in-class in 3 of them: customer service, regulatory, asset management
- While still early, already down path of developing and embedding improvements across 10 core capabilities
- Assessment, development and acquisition of talent remains a critical focus

Achieving excellence in these areas prepares and earns us the right to grow beyond our core business

[redacted]

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Sensitivity of key economic drivers

Drivers	Starting point	Sensitivity	Earnings impact ($M average annually, 2017-2021)
Approved OM&A (% of investment plan)	100% of planned OM&A approved by OEB	[redacted]	
Approved capital (% of investment plan)	100% of planned Capital approved by OEB		
Cost efficiencies ($M of OM&A efficiencies realized)	No OM&A efficiencies realized		
Load (% variance to forecast)	No variance to forecast		
Allowed return on deemed equity (% return on equity)	9.19% (2016 actual)		

[redacted]

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[redacted]

1. Based on last 5 years of Hydro One filings and recent filings from other Ontario distribution companies

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Back-up

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Variety of appropriate delivery models considered

[redacted]

Delivery Activity	Traits	Owner-managed (OM)[1]	Engineering Procurement & Construction Mgmt	Design & Construct	Engineering Procurement & Construction	Build Own Operate / Build Own Operate Transfer
Overall	**Typical value driver**	System performance	System performance, schedule, cost	Schedule, system performance, cost	Schedule, cost, system performance	Moving scope off balance sheet
Engineering	**Ability to influence design**	High	High	Up to detailed design	Early design input only	Minimal
Procurement	**Ability to influence procurement (e.g. free issue, strategic sourcing)**	High	High	Medium	By exception	By exception
Construction	**Transfer of productivity risk**	Low – in contracting model only	Low – in contracting model only	Medium	High – market dependent	High – market dependent
	Ability to influence constr. methodology	High	High	Medium	Early input only	Low
	Ability to influence contract packaging	High	High	Low - by exception	Low	No
	Ability to influence schedule (e.g. early works, putting on hold)	Yes	Yes	Limited (claim implications)	Limited (claim implications)	Limited (claim implications)
O&M	**Ownership of operations**	Owner	Owner	Owner	Owner	Transfer over agreed time

Unlikely fit

1. Includes integrated team

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Opportunity to shift delivery model in certain segments

[redacted]

Hydro One's volume of replacement over the plan period is higher primarily due replacement criteria that were not included in the EPRI report. These criteria include obsolescence concerns, safety concerns (e.g. lack of or insufficient arc resistance rating), change in system conditions (e.g. short circuit level), polychlorinated biphenyl ("PCB") mitigation per regulatory requirements and integrated investments. Further details on the reasons can be found in Section 3.2.4 of the TSP.

1.4.2.4 DERIVATION OF OVERHEAD CONDUCTOR HAZARD FUNCTION

This report describes EPRI's efforts to develop a conductor hazard curve and its ESL which can be used to project expected replacement needs for planning purposes.

The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition..

1.4.2.5 OPERATING SPARE TRANSFORMERS REQUIREMENT ASSESSMENT

The purpose of this study is to verify that Hydro One's spare transformer requirements are appropriate and consistent with industry best practices. Hydro One uses the Markov Model to determine the appropriate number of spare transformers required to ensure continuity of electricity supply to customers, safety and reliability. The Markov Model takes into consideration the probability of failure, carrying costs and procurement lead time to determine the most cost-effective number of spares to be kept in inventory. EPRI has developed analytics to optimize the power transformer spares practice which was compared with Hydro One Markov modeling.

utilization of the relay fleet while managing its associated risk. For the time being, Hydro One will maintain the current ESL for all solid state and microprocessor-based relays systems as 25 years and 20 years, respectively as described in Section 2.2.

Specific integrated investments that include the replacement of protection system over the next five years are further described in ISDs SR-01, SR-02, SR-03, SR-04, SR-05, SR-06, SR-07, and SR-08.

3.2.4.9 Degradation Rates of Steel Tower Coating Systems

The EPRI study supports Hydro One's current investment plan by validating the existing approach and assumptions. Using the findings of the study, Hydro One continues to focus on coating steel structures in C4 and C5 corrosion zones whose age has reached 35-75 years of age.

3.2.4.10 Derivation of Overhead Conductor Hazard Function

The purpose of this EPRI study is to provide valuable insights into fleet mean life expectancy from analysis of historical condition assessment and replacement data pertaining to overhead conductors. In particular, this study presents EPRI's analysis to develop a conductor hazard curve and its ESL which can be used to project expected replacement needs for planning purposes.

As a result of the study, Hydro One has changed its conductor ESL from 70 to 90 years. The EPRI report forecasts that 3,920 circuit km of the ACSR conductor fleet will be at End-Of-Life ("EOL") or near EOL condition by 2024.[3] This forecast of ACSR conductor condition aligns with the fact that by the end of 2024, about 13% or 3,653 circuit km of the overall conductor fleet will reach or exceed their ESL without further replacements.

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[3] TSP Section 1.4 Attachment 4 - Derivation of Overhead Conductor Hazard Function, section 5-3, p 93.

1
INTRODUCTION AND BACKGROUND

Introduction

Hydro One Networks Inc., like many utilities, is striving to maintain the reliability of its transmission network while controlling maintenance, repair and replacement costs. Aging equipment, more stringent operating requirements, financial constraints and retiring expertise have made the management of transmission line assets increasingly challenging.

To address these challenges, Hydro One is reviewing its maintenance and replacement practices to ensure they are underpinned by sound evidence. This includes the use of condition and risked-based maintenance and replacement scheduling using advanced analytics-based techniques. Understanding the condition and remaining life of conductors would help transmission asset managers make better decisions about conductor maintenance, repair, and replacement.

As part of this asset management effort, Hydro One asked EPRI to investigate available Hydro One overhead transmission line conductor demographic and condition data and determine what insights could be obtained to support asset management decisions.

This report describes the EPRI investigation.

Background

Hydro One's service territory is the size of Texas plus California, and driving across it can take three days. Most of the province's population is concentrated along the southeastern border far from hydroelectric generating stations. Long transmission circuits as well as widely distributed substations are required to deliver power over these distances. These transmission and distribution assets are exposed to environmental stresses, including severe weather and temperature variations that can degrade equipment over time.

Hydro One defines Expected Service Life (ESL) as the average age in years that an asset can be expected to operate under normal system conditions. Half of the assets are expected to operate beyond this ESL. Hydro One also defines End of Life (EOL) as the state of having a high likelihood of failure, or loss of an asset's ability to provide the intended functionality as determined through diagnostic data, wherein the failure or loss of functionality would cause unacceptable consequences. EOL is always determined by condition assessment.

One asset of interest, and the focus of this report, is Hydro One's overhead transmission line conductor fleet. Hydro One's estimated ESL for conductors is approximately age 70. Based on past experience, condition assessments are not conducted before 50 years of age. As shown in Figure 1-1, many of the fleet conductor assets are beyond their presently used ESL.

UNDERTAKING - JT 1.1

Reference:
I-01-OEB-062

Undertaking:
To confirm that Hydro One asserts that an analysis based upon data set that includes removals for all causes, including failure and non-failure replacements, and one that does not include non-failure removals, would generate identical condition-based end of life results.

Response:
Hydro One has provided an update to Interrogatory I-1-OEB-62 found in Attachment 1 to align with EPRI's guidance regarding this Undertaking and the analysis it conducted.

The analysis referenced in the undertaking would generate a hazard function not a condition-based end of life result.

EPRI has advised that the hazard function (or Weibull model) derived from failure and non-failure data would not be identical to the hazard function derived from failure only data. Any similarity between the two functions would be dependent upon the proportion of failure removals to non-failure removals in the data set used to derive the function. Therefore, if a large portion of the removals were for failures and only a small portion were due to non-failures, the two functions would tend to converge i.e. they would be similar.

Given an understanding for the basis for transformer removals, it is reasonable to consider the removal hazard function as a good proxy for the failure hazard function, especially for younger transformers (younger transformers are rarely replaced except for failure). Therefore, it is expected that if the data allowed that only failure data were used, the cumulative hazard function would look very similar to the one presented in Region 1 of Figure 1 below (red line), which was derived from Hydro One's removal data. In this region, the cumulative hazard function derived from the Weibull model (red line) matches the cumulative hazard function calculated from the actual event data (black line). In Region 2 the cumulative hazard function derived from Hydro One's removal data (black line) is much steeper than the cumulative hazard function derived from the

Weibull model (red line). EPRI's report[1] proposed that this may be due to either a "failure process that is more dominant in older units" or a "result of discretionary replacement decisions" or a combination of both. Hydro One does not run its transformer fleet to failure as this would be imprudent and would elevate safety and system risk. Rather Hydro One replaces transformers before failure driven by condition criteria that demonstrate the transformer has reached end of life.

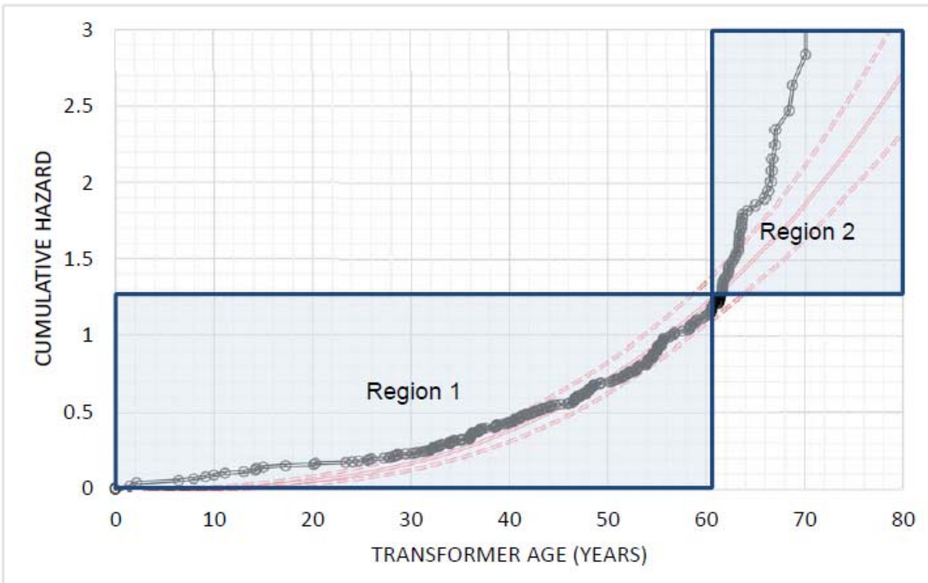

Figure 1: Comparison of Model and Sample Cumulative Hazard Functions 115 kV Transformers - Exhibit B-1-1 TSP 1.4 Attachment 2, Figure 2-4 on page 2-6.

[1] Exhibit B-1-1 TSP Section 1.4 Attachment 2 page 2-6

OEB INTERROGATORY #62

Reference:
TSP-01-04-02 p. 21 & 25TSP-01-04-03 p. 21

Interrogatory:
At the first reference above, EPRI stated the following:

However, removed from service data is more abundant and consist of 419 transformers within a period of 1981 to first quarter 2017. The reasons for removal are not supplied in data, therefore failures and discretionary replacements cannot be distinguished. Since the reason is not supplied a time-to-event model can be developed where the event, rather than failure, is removal.

At the second reference above, EPRI stated the following:

Fitting the data to the Model
The removal rate model is verified by comparing the sample cumulative hazard function calculated from the actual event data (previously described) against the cumulative hazard functions created from the Weibull model. There are cumulative hazard functions for each MCMC observation. For each age from 0 to 100, we calculate the median cumulative hazard rate and the corresponding 95% credibility interval.

At the third reference above, EPRI stated the following:

Removed from Service Data
The removed from service data provided by Hydro One consists of 1218 circuit breakers as of third quarter 2017. No reason for removal was provided.

a) Please confirm that the term “removals” is not synonymous with the term “failures”.

b) Removals are being used to create a “hazard” curve, even though the reasons for the removals have not been categorized. Is this methodology appropriate as EPRI is applying it here?

Witness:Donna Jablonsky

c) A true "Hazard Rate" implies an age-related likelihood of failure. Please confirm that the supplied input data does not support the determination of a true Hazard Rate for these assets.

d) Based on the above references, it appears that EPRI has used uncategorized asset removal data in its derivation of Hazard Rates because that was the data set provided by Hydro One, rather than because the data is fit for purpose. Does the lack of categorization of retirement causes in the data supplied to EPRI potentially invalidate the conclusions drawn in the both the "Derivation of Circuit Breaker Hazard Functions" report and the "Derivation of Transmission Substation Transformer Hazard Functions" report?

Response:

a) Confirmed. The term “removals” is not synonymous with the term “failures.” Removals may include but are not limited to “failures”.

b) Yes. The methodology is mathematically appropriate for developing a removal hazard curve. See the further discussions in c) and d) below.

c) Confirmed, the supplied data was for removals for any reason and therefore may have included both failure and non-failure related data. No, a hazard rate does not need to be restricted to failures only.

“Hazard rate” is a statistical term used as one way to mathematically describe the functional relationship between the waiting time and the occurrence of a well-defined event. The analysis of such relationships often is called time-to-event analysis. The event depends on the focus of the study. In the EPRI analysis under discussion, the defined event is removal for any reason. Where the hazard rate of interest is that for failure, the terms hazard rate and failure rate are often used interchangeably.

d) No, the asset removal data EPRI analyzed does not invalidate the conclusions presented. It is reasonable to believe that, given the expenses involved, removals of transmission assets were done for well-considered reasons such as (1) actual failure, (2) increased risk of failure beyond acceptable limits or (3) unacceptable maintenance costs. There is very little reason for removing from service a young transformer other than (1) or (2) above. Therefore, it is reasonable to consider the removal hazard rate as a good proxy for the failure hazard rate, especially for younger transformers.

Witness: Donna Jablonsky

For older transformers, the replacement rate was found to be much steeper. EPRI's report[1] proposed that this may be due to either a "failure process that is more dominant in older units" or a "result of discretionary replacement decisions" or a combination of both. Hydro One does not run its transformer fleet to failure as this would be imprudent and would elevate safety and system risk. Rather Hydro One replaces transformers before failure driven by condition criteria that demonstrate the transformer has reached end of life.

[1] Exhibit B-1-1 TSP Section 1.4 Attachment 2 page 2-6

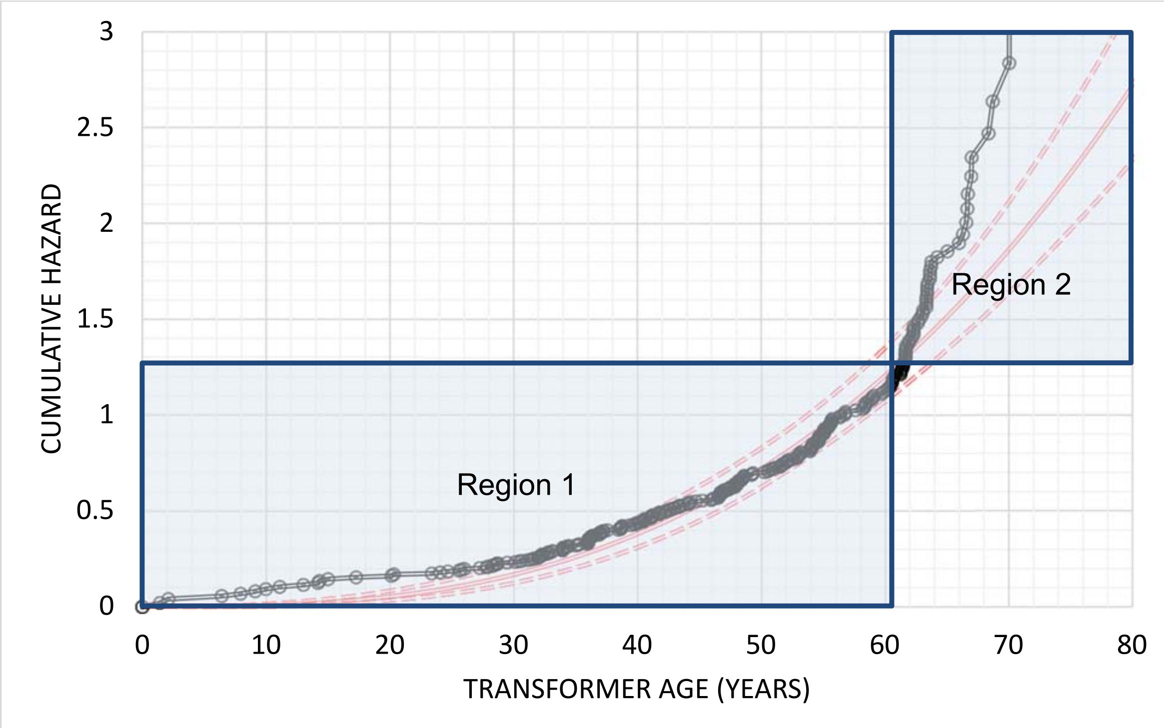

Figure 2-4
Comparison of Model and Sample Cumulative Hazard Functions 115 kV Transformers

Figure 2-4 for the 115 kV transformer group show two regions with different levels of agreement between the red and black lines. A good Weibull model fit for most of the life (Region 1) and a much steeper replacement rate (black line) than provided by the Weibull model in later life (Region 2). However, younger power transformers are rarely replaced except for failure. Therefore, Region 1 may be a reasonable model for the failure hazard rate. The break points between the two regions could indicate the following:

- The onset of a failure process that is more dominant in older units.
- The result of discretionary replacement decisions.
- Some combination of both failure process and discretionary replacement.

Since the reasons for removal are not noted, failures and discretionary replacements cannot be distinguished.

Modeling Assumptions

- The starting data is complete and contains all removals and in-service units for the period within 1981 through first quarter 2017.
- The criteria for removal have been constant over the historical period being analyzed.
- Future criteria for removals will be the same as in the past.

2
REMOVAL RATE MODELING

Data Review

Originally Hydro One sought to obtain a year-by-year prediction of the expected number of transmission substation transformer failures for the next five years. However, the supplied failure data appeared sparse in relation to the number of transformer-years experienced and consequently the derivation would not provide a usable failure hazard rate. The failure data provided for the period of 2006 through 2016 consists of 42 failures. Confidence limits for any derived hazard rate would be large using this supplied failure data as noted in Figure 2-1. For example, for the failure rate of derived from this data could be anywhere between approximately 0.6% and 2% for a 60 year old transformer using a 95% confidence band. For a 40 year old transformer the failure rate could be anywhere between approximately 0.3% and 1%.

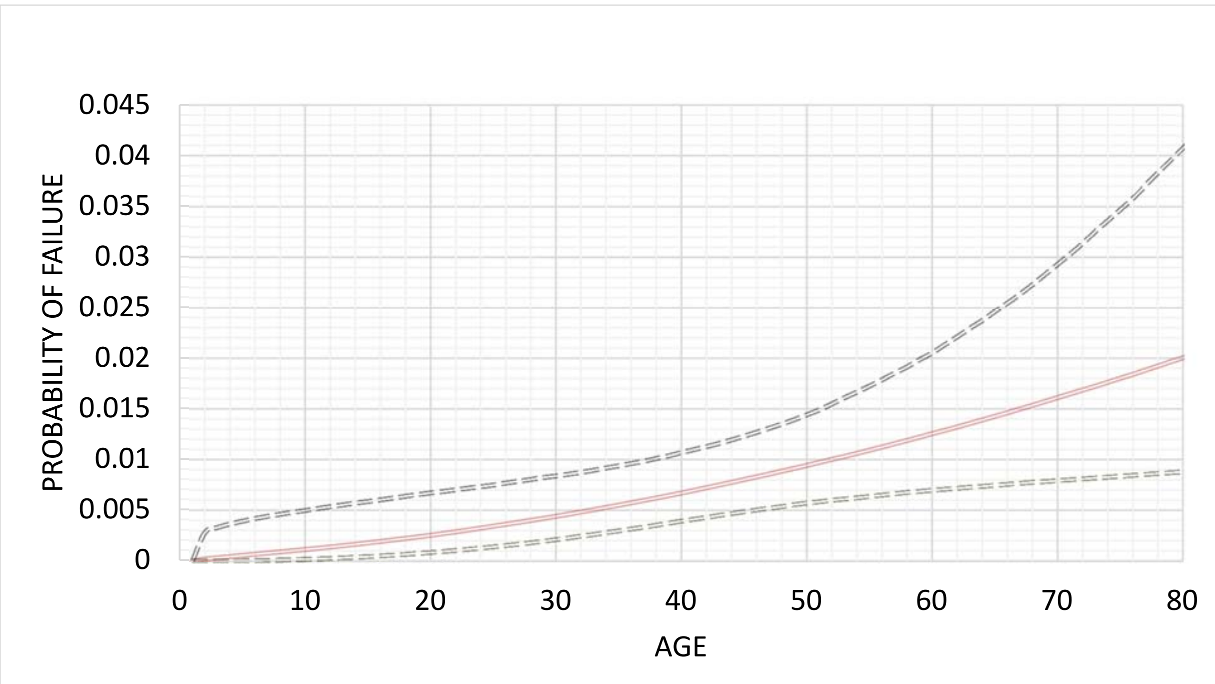

Figure 2-1
Failure Hazard Rate Derived from Spares Data

However, removed from service data is more abundant and consist of 419 transformers within a period of 1981 to first quarter 2017. The reasons for removal are not supplied in data, therefore failures and discretionary replacements cannot be distinguished. Since the reason is not supplied a time-to-event model can be developed where the event, rather than failure, is removal.

Figure 2-2 show the Service Ages of the 115 kV transformer group using data from both the removed from service (left) and failures (right). In the Service Ages plot, the horizontal axis is the age of the transformers. Each horizontal line represents a distinct transformer denoted by an

3.2.4.1 Operating Spare Transformers Requirement Assessment

This study found that the results of Hydro One's Markov model analysis (used to determine the appropriate number of spare transformers), aligns with the independent and alternative analysis from the third-party expert, Electric Power Research Institute ("EPRI"). Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost efficiency.

3.2.4.2 Derivation of Transformer Hazard Functions

This study confirmed that Hydro One's pacing approach to the replacement of transformers is appropriate. This pacing of transformer replacement has been reflected in the following ISDs: SR-02 (Station Reinvestment Projects), SR-03 (Bulk Station Transformer Replacement Projects), SR-05 (Load Station Transformer Replacement Projects), and SR-08 (John Transformer Station Reinvestment).

3.2.4.3 Derivation of Circuit Breaker Hazard Function

This study was performed by EPRI and describes EPRI's efforts to (i) model and develop circuit breaker removal rates from historical replacement records and (ii) apply them to forecast the number of circuit breakers expected to require replacement based on past practices. EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker historical removals and applied it to the Hydro One's circuit breaker fleet. Using Hydro One's circuit breaker retirement data, EPRI modeled Hydro One's circuit breaker removals and has forecast probable future removal rates. The study confirmed that Hydro One is replacing younger circuit breakers at a rate expected from the statistical model. However, older circuit breakers are being replaced at a quicker rate than expected. The reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report as explained below.

Hydro One plans to address 638 breakers over the planning period. This includes the removal of 49 breakers as a result of station decommissioning and reconfiguration as well

look at these projects first for reprioritization. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

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

Table 1: Summary of Transmission OM&A Expenditures ($ millions)

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Category Level										
Sustainment	233.6	238.7	215.1	241.1	218.1	241.2	229.4	238.5	200.6	214.2
Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	53.4	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	11.0	3.9	7.3	7.5
Common Corporate Costs and Other Costs[1]	73.9	70.2	60.1	71.3	41.5	49.9	54.9	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	65.3	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		
Directive *									-0.1	-0.1
Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**375.8**
% Change Year over Year			-7.6%		-5.6%		8.9%		-9.6%	5.4%
Variance to Plan	10.4		-28.7		-12.7		24.9			

*Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

Hydro One's 2019 OM&A expenses are expected to be $38 million or 9.6 percent lower than the 2018 plan funding envelope. This OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One's planned asset maintenance cycles, and corporate cost reductions, which are described further within Section 6 of this Exhibit. Hydro One plans to increase its 2020 OM&A expenditures by 5 percent from 2019 levels while still remaining 4.7 percent below the 2018 plan funding

[1] Common Corporate Costs and Other Costs includes Planning, (exhibit F-02-03), CCF&S (exhibit F-02-02), Information Technology (exhibit F-02-04), Cost of External Revenue (exhibit F-02-05), and Other OM&A (exhibit F-02-01).

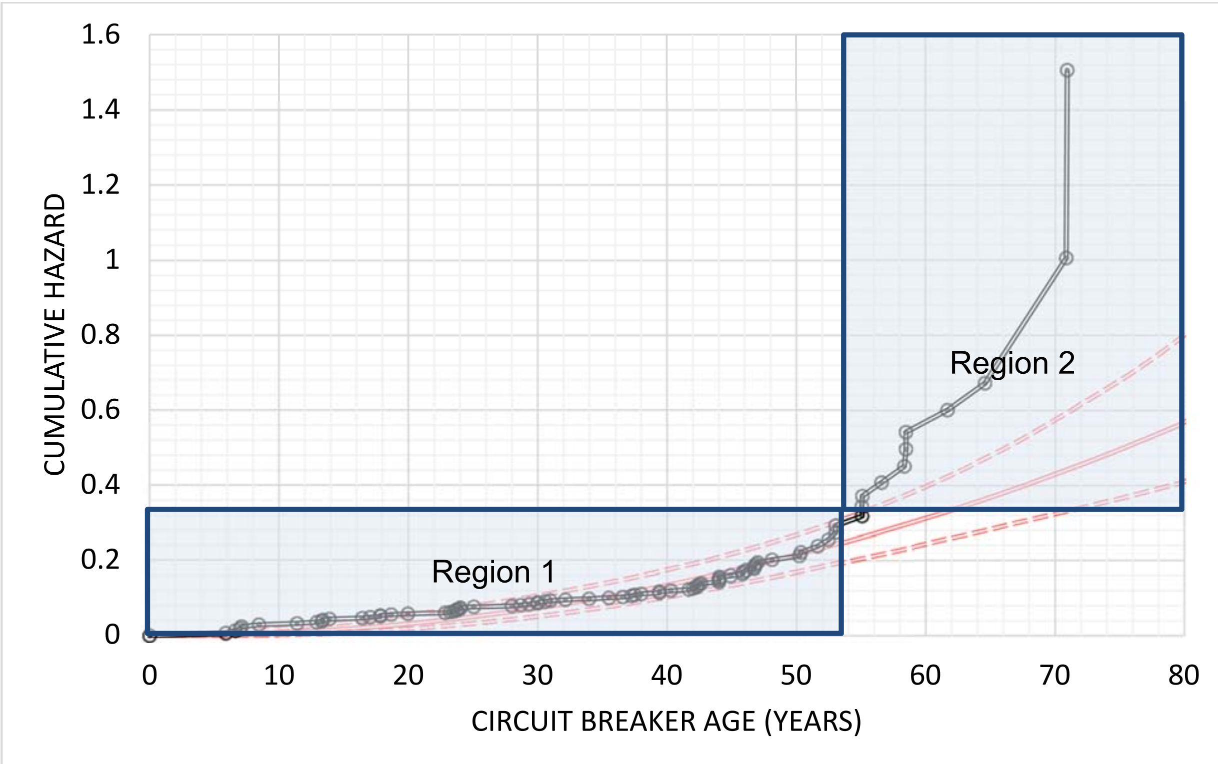

Figure 2-2
Comparison of Model and Sample Cumulative Hazard Functions44kV Oil Circuit breakers

Figure 2-2 for the 44 kV oil circuit breaker group show two regions with different levels of agreement between the red and black lines. A good Weibull model fit for most of the life (Region 1) and a much steeper replacement rate (black line) than provided by the Weibull model in later life (Region 2). However, younger power circuit breakers are rarely replaced except for failure. Therefore, Region 1 may be a reasonable model for the failure hazard rate. The transition point between the two regions could indicate the following:

- The onset of a failure process that is more dominant in older units.
- The result of discretionary replacement decisions.
- Some combination of both failure process and discretionary replacement.

Since the reasons for removal are not noted, failures and discretionary replacements cannot be distinguished.

Modeling Assumptions

- The starting data is complete and contains all removals and in-service units for the period within 1982 through third quarter 2017.
- The criteria for removal have been constant over the historical period being analyzed.

- Future criteria for removals will be the same as in the past.
- Any external effects on removal rates (e.g. budget constraints) were constant over the historical period and will be unchanged over the forecast period.
- Underlying wear-out processes will not change.
- It is important to note that the hazard rate function derived is for removals, not failures.

Modeling Results

There are currently 443 circuit breakers in service of various ages in the 44 kV oil group. Based on the age of each individual circuit breaker, the distributions of the number of removals was predicted from a Monte Carlo simulation.

Each of the 9,600 pair results from the analyses results (Figure 2-1) is used in a Monte Carlo simulation to generate the expected number of removals. Each shape and scale pair defines a Weibull distribution. This distribution is applied to each of the in-service circuit breakers and the number of removals are summed for the total population for that particular distribution.

The resulting histogram of the sum of the number of removals recorded in each plot (Figure 2-3) gives the probability distribution of removals. The entire process is then repeated for the next year with each circuit breaker's age incremented by one.

Figure 2-3 shows the predicted number of removals of the currently in-service circuit breakers for each of the next five years and the five year total.

The figure can be interpreted as probability distributions. For example, in the plot for year 1, adding up the probabilities corresponding to 0 through 8 removals, we can say that we are 99% certain that the number of circuit breaker removals will be 8 or fewer.

as the additional installation of 15 breakers resulting from customer requests to increase operational flexibility in the Toronto area. As per the EPRI analysis, there is a 90% probability that Hydro One will need to replace 491 breakers or fewer. However, Hydro One's volume of replacement over the plan period is higher primarily due to obsolescence concerns, safety concerns (e.g. insufficient arc resistance), PCB mitigation, and integrated investments which are not reflected in the EPRI analysis.

The EPRI analysis is derived from asset retirement data from 1981 to 2017. The analysis does not reflect the necessary replacement of 95 ABCBs over the planning period due to worsening reliability, as Hydro One has operated its fleet longer than industry peers. Similarly, the historical mid-life refurbishment of oil breakers from 1950 to 2007 has enabled Hydro One to operate approximately 300 currently in-service breakers for a longer period prior to retirement. Based on how the calculations were performed, this skews the predicted replacement rate. PCB mitigation also contributes to the increased rate of replacement in order to meet federally legislated deadlines. Out of the 247 oil circuit breakers identified for replacement over the planning period, 69 (28%) have measured above the acceptable level of 45 ppm for PCBs. Due to increased obsolescence concerns and the lack of, or reduction of, vendor support with respect to oil, metalclad, and vacuum breakers, the capital plan paces breaker replacements to mitigate reliability impact. Where breakers that are not end of life are removed from service because it is part of an integrated investment (e.g., due to the replacement and relocation of a switchyard), these breakers are placed into spares to support the remaining fleet. Oil circuit breakers can be salvaged for parts to support the remaining fleet, while complete SF6 breakers are placed into the spare equipment pool to support demand replacements.

This pacing of circuit breaker replacement has been reflected in the following ISDs: SR-02 *Station Reinvestment Projects*, SR-04 *Bulk Station Switchgear and Ancillary Equipment Replacement Projects*, SR-06 *Load Station Switchgear and Ancillary Equipment Replacement Projects*, and SR-08 *John Transformer Station Reinvestment*.

look at these projects first for reprioritization. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

Table 5 - System Access - Material Capital Investments Proposed

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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
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Table 6 - System Renewal - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
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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

Table 1: Summary of Transmission OM&A Expenditures ($ millions)

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Category Level										
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Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	53.4	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	11.0	3.9	7.3	7.5
Common Corporate Costs and Other Costs[1]	73.9	70.2	60.1	71.3	41.5	49.9	54.9	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	65.3	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		
Directive *									-0.1	-0.1
Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**375.8**
% Change Year over Year			-7.6%		-5.6%		8.9%		-9.6%	5.4%
Variance to Plan	10.4		-28.7		-12.7		24.9			

*Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

Hydro One's 2019 OM&A expenses are expected to be $38 million or 9.6 percent lower than the 2018 plan funding envelope. This OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One's planned asset maintenance cycles, and corporate cost reductions, which are described further within Section 6 of this Exhibit. Hydro One plans to increase its 2020 OM&A expenditures by 5 percent from 2019 levels while still remaining 4.7 percent below the 2018 plan funding

[1] Common Corporate Costs and Other Costs includes Planning, (exhibit F-02-03), CCF&S (exhibit F-02-02), Information Technology (exhibit F-02-04), Cost of External Revenue (exhibit F-02-05), and Other OM&A (exhibit F-02-01).

if you go to Staff 73 (a), there is a statement by METSCO in which you were asked to confirm -- which essentially said risk is probability times consequence; I am paraphrasing.

But your response to 71 (c) is that the sub indices in your risk process do not inform either probability or consequence, and I was hoping to have clarification.

MR. JESUS: So I think, for the purpose of item (c) here, the facts associated with the specific transformer or asset that's in question, the asset analytics would provide the condition information, the performance information, the criticality of the unit, the utilization, how much money we're spending on the unit, how old it is. So they would provide that information.

The actual probability times consequence is not being carried out in the asset analytic solution. It's actually being carried out in our asset investment planning tool, i.e. Copperleaf.

So the probability and the consequence are in fact being informed by the facts presented from the asset analytic solution.

MR. WALSH: Okay, thank you. Under Staff 73(e) and (f), parts (e) and (f), part (e) provided a graphic to illustrate the notion of the worst reasonable outcome.

Can you confirm if Hydro One ever uses the worst reasonable outcome to represent the expected consequence of failure?

MR. JESUS: So planners are constantly using the worst reasonable outcome to make asset is investment decisions. The assessment is informed by the asset risk assessment and they're taking what is the most reasonable, credible case or consequence to be used in the assessment.

MR. WALSH: I'm sorry, could you repeat that?

MR. JESUS: So planners are using the worst reasonable outcome, i.e. the most reasonable outcome or consequence associated with an event, to assess the consequence as part of the risk assessment.

MR. WALSH: Okay. If I have understood correctly, worst reasonable outcome is approximately one standard deviation away from most probable outcome. What is the associated probability of worst reasonable outcome?

MR. JESUS: So the worst reasonable outcome is a one standard deviation away, and it's not the most probable. These are probabilities, and the intent is to identify what a reasonable outcome or event could occur.

So a good example is a line being held by an insulator. If it's a brand new insulator, is there a probability that that conductor can fall? Absolutely. Is it credible? Is it reasonable, given that it's a new insulator? No.

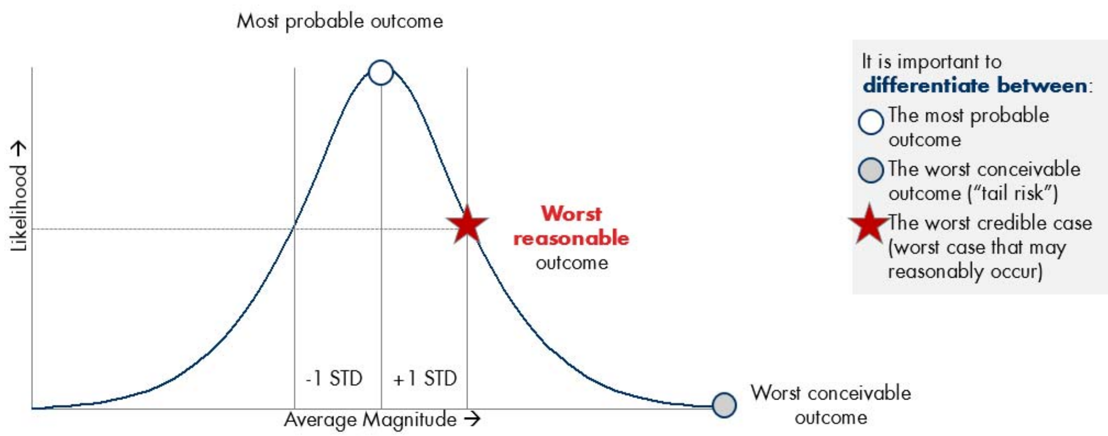
But a 60-year old insulator that is CP, or Canadian porcelain, Canadian Ohio brass with known defect issues, is the worst credible case that the conductor could fall and injure someone from a safety point of view? Absolutely. That would be the most credible case.

So when we are doing the investments, we look at what

c) No. It is more than a modest incremental adjustment.

d) Please refer to c) above.

e) From the perspective of a hypothetical risk distribution curve, the worst reasonable outcome would lie approximately 1 standard deviation away from the most probable outcome, as shown in the illustrative example below:



f) Confirmed.

i. N/A

ii. Hydro One subsequently applies a modifier to translate from the most probably outcome to the worst reasonable outcome – for example, if there is a certain set of coincident circumstances required for a worst reasonable outcome to materialize, the joint likelihood of the triggering event and coincident event is used.

iii. N/A

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

The following section describes how the AA outputs, once generated in accordance with specifications related to each asset class, undergo further assessments in the subsequent stages of the ARA process.

2.1.2. *Asset Risk Assessment (ARA) Capability Characteristics*

Asset Risk Assessment (ARA) entails a full-spectrum asset management planning process that identifies the asset candidates to be included in the scope of the investment projects, of which AA is an input component used in conjunction with other input parameters, including:

- Asset class strategy and technical assessment documents, which utilize AA results and underlying data points in their analysis;
- Customer needs and preferences related to particular asset classes;
- Legal and regulatory requirements relevant for consideration;
- System planning and coordination requirements affecting potential intervention options;
- Health & Safety, environmental, and obsolescence-related;
- Field inputs, maintenance notifications, and relevant event investigations;
- Results of detailed assessments and diagnostic testing; and
- Field visit validation of asset needs suggested by ARA analysis.

Figure 3 illustrates the entire scope of the ARA process.

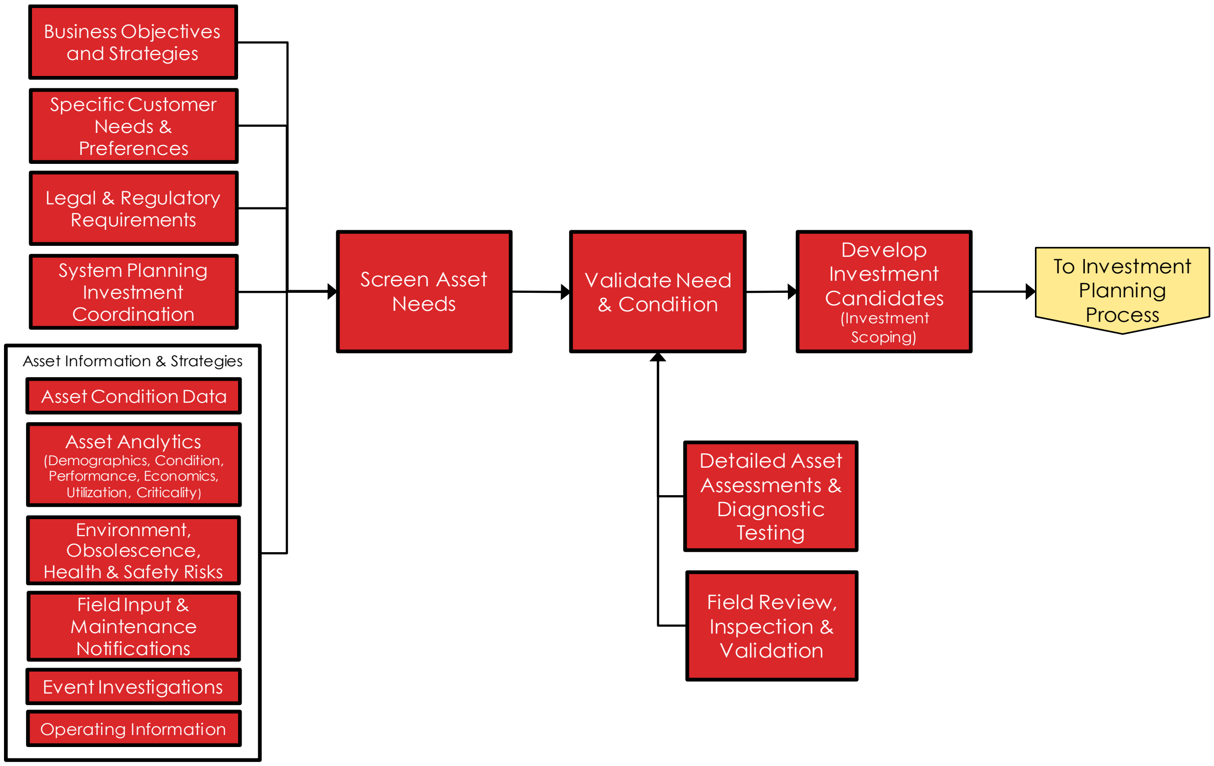


Figure 3. Asset Risk Assessment Process

Overall, the ARA functionality serves to expand upon the initial prioritization as established by AA, by allowing asset planners and managers to assess and stress-test the insights produced by the AA functionality in the context of incremental data points, and considerations that connection field data with the broader strategic, planning, and regulatory environment in which Hydro One operates.

2.1.3. *Reliability Risk Forecasting Capability Characteristics*

Reliability Risk Model is a standalone tool designed to develop system-level forecasts of changes in values of reliability risk relative to the capital investment levels underlying a particular scenario. METSCO understands that up to this point in its existence, the RRM's outputs were only used in the context of customer engagement meetings, to represent directional implications of reliability risk relative to the range of investment levels contemplated by the utility.

Given its current utilization, the tool and its outputs help contextualize Hydro One's investment considerations to customers, acting as a supporting mechanism in gathering customer feedback that is considered in the course of investment planning. With the exception of this indirect contribution into the investment planning activities, the tool

OEB INTERROGATORY #55

Reference:
TSP-01-04 p. 22

Interrogatory:
At the above noted reference, Hydro One stated that "Half of utilities refurbish transformers to extend life."

a) Does Hydro One refurbish transformers to extend life?
   i. If yes, please provide documented examples of refurbishment vs. retirement decisions.
   ii. If no, please explain why not.

b) If one exists, please provide the formula used by Hydro One to establish refurbishment investment limits, driven solely by estimated remaining service life (defined as ESL minus actual age).
   i. Once an asset has exceeded ESL, what is the maximum allowed refurbishment investment?

Response:
a) No, power transformers are refurbished to preserve their expected service life and reliability, not to extend their life.

b) Hydro One employs a model that provides the Present Value for three options: maintain status quo, refurbish, or replace. It uses several factors such as maintenance cost, replacement cost, tax capital cost allowance, and the discount rate. Please refer to Interrogatory I-01-OEB-19 Attachment 1 for an example.
   i. There is no set value and the maximum allowed refurbishment cost will depend on the evaluated asset.

Witness: Donna Jablonsky

would you then decide to spend more money to get the same result?

MS. JABLONSKY: This varies, actually, because this will be based on other work that's in the queue to be done at the time. So it's assessed per transformer. So the decision that's made would be as per this unit and where it fits in the work program at that time.

So sometimes a decision would be to follow that as well as to do status quo or major repair based on what else is in the queue to be done, because both these require a planner's intervention.

MR. WALSH: So the "status quo maintain", would that be representative if the planner said that there has to be major maintenance? Would that be a fair representation of this net present value expectation?

MS. JABLONSKY: When we do maintenance on these units and we collect data for the assessment of the unit, status quo is a last resort for us, because if there's an issue that's prominent with the unit it should be addressed. So status quo, unless the replacement of the unit is within the next year, is not the field that we go to. So it's refurbish, a known issue with the unit would be the preferred.

MR. WALSH: Okay, thank you. So just to clarify, if you did a major maintenance would it change the expected duration, remaining life of the asset?

MS. JABLONSKY: It would not change the expected service life of the asset. The asset may live beyond that, but it would not change the recorded ESL of the asset.

MR. WALSH: So -- and just to clarify, each asset has its own individual ESL or each asset has the ESL that's attributable to that asset class?

MS. JABLONSKY: The ESL is on the fleet level. So the asset -- all asset in that -- that particular asset, they all have the same ESL date time frame to them.

MR. WALSH: Okay, thank you.

MS. JABLONSKY: The condition assessment is on the individual level.

MR. WALSH: Okay. If we can go to the graph that follows this, so on the next page. On this graph and on the Marathon there's a similar graph, but at the top of this graph and the title -- or just below the title it says that the replace asset life is 40.

So am I correct in understanding that under the assumption that you've replaced the asset that the expected service life of the asset would be 40 years?

MS. JABLONSKY: Please repeat your question.

MR. WALSH: Under this -- under the table that's above, at the -- just below the title it reads "replacing asset cost 580K and replacing asset life 40." Am I to understand that the assumptions if you replace the asset and that's being used in the calculations in the previous table, is that the asset would last for 40 years?

MS. JABLONSKY: No.

MR. WALSH: Could you explain what the 40 means?

MS. JABLONSKY: The 40 is the ESL of the asset. This

7.2 Net Present Value Analysis

This section evaluates the cost benefit for various asset management options (Status Quo Maintain, repair, replacement) of T13 with Net Present Value Analysis (NPV).

- Status Quo Maintain: Perform routine maintenance to keep the unit in service. Replace at economic end of life (2021). Continue to maintain new unit to end of study period (2081).
- Repair/Refurbish: Perform major repair/refurbishment in the year of interest (2017), then maintain as normal and replace the unit at economic end of life (2021). Continue to maintain new unit to end of study period (2081).
- Replace: Advance the replacement to the year of interest (2017) instead of performing a refurbishment. Continue to maintain new unit to end of study period (2081).

The study makes the following assumptions:

- Study period : 64 years[1]
- T13 will undergo refurbishment/ repair at 60 year old (2017), at approx. CAD$583.8k[2].
- Replacement cost is assumed to be CAD$5.8M[3] for a unit that matches purchasing standard S115-106
- The new unit will benefit from lower OM&A cost because it will be equipped with vacuum tap changer. Estimated interval for internal inspection is lengthened to 12 years. New unit will utilize Buchholz relay and eliminate D2 maintenance task.
- Inflation: 2%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0
- Average corrective cost of CAD$8K per year. (Total : CAD $32K)

NPV of 3 options (Status Quo Maintain, Repair and Replace) were evaluated under the aforementioned assumptions. In general, NPV calculation has preferred the option to maintain status quo and wait for replacement as it has the lowest present value.

Should a repair becomes necessary, the maximum economically viable budget to repair/refurbish the unit is CAD $583.8K - CAD $39.88K = CAD $543.92K. Therefore, the model suggests that it will be more economical to replace instead of to repair/refurbish the unit when T13 reaches 60 years old and onwards.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
With CCA tax savings				
PV of Options, $k, with terminal value	5262.46	5809.02	5769.14	
PV of Options, $k, terminal value = 0	5377.25	5923.81	5993.20	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-546.56		Maintain
Major Investment (Repair/Refurbish) - Replace		39.88		Further Review
Repair - Replace boundary			543.92	
Repair - Replace boundary, upper bound			598.31	
Repair - Replace boundary, lower bound			489.53	

Table 7: Present Value comparison for different sustainment options.

[1] Study period lengthen to 64 years to accommodate the fact that the unit is already 60 years old. Normal Study period is 40 years
[2] $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
[3] Based on 2015 March, Average I/S Cost for Power Transformers in 115kV class.

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and prioritized based on the level of risk mitigated and the cost and value delivered toward achieving business objectives.

The overall Investment Planning process is set out below in Figure 1**.**

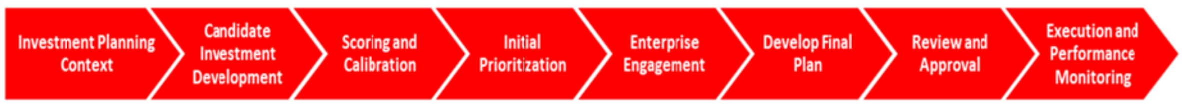

Figure 1 – Improved Eight-Step Investment Planning Process

Key improvements to Hydro One's investment planning process include the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and
- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

Hydro One management at all levels, including the Executive Leadership Team ("ELT"), are involved in the investment planning process to develop an investment plan that achieves the overall corporate strategy, efficiently mitigates risks, and delivers value to customers.

The Investment Planning process generates an annual budget for Operations, Maintenance and Administration ("OM&A") and capital work programs, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements. The 2020-2024 Investment Plan presented in this TSP is a product of the improved investment planning process.

are kept up-to-date and accurate, the strategies are regularly reviewed. Since the Prior Proceeding, Hydro One has reviewed and revised strategy documents for the majority of Transmission Lines, Stations and Protection & Automation assets. These are among the most critical assets in Hydro One’s transmission system. To further strengthen Hydro One’s asset management capabilities, the development of new strategy documents for minor assets is currently underway.

Outcomes Tracking

Guided by the BCG recommendations outlined in the Investment Planning Process Review, Hydro One implemented a new process step in 2018, which included an upfront identification of corporate strategic direction, the establishment of interim targeted outcomes and more granular, strategic budget allocations based on operational, financial, regulatory and customer considerations at the beginning of the investment planning process.

Hydro One conducted a strategic budget (capital/OM&A) allocation at the beginning of the process, whereby the plan was divided into smaller, discrete budgets based on business unit, and then investments were subsequently prioritized within those budgets. The basis for this upfront allocation was the expenditure levels included in the previous plan, adjusted for efficiency gains and new strategic directions, as illustrated in Figure 1 below. This was done by business unit, resulting in nine allocations.

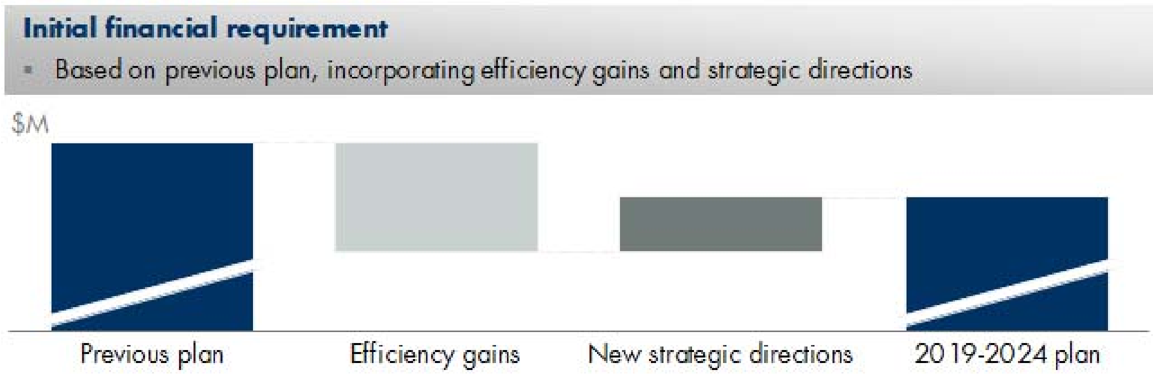

Figure 1 – Illustration of Initial Strategic Budget Allocation

The nine allocations are: Transmission Power Systems, Distribution Power Systems, System Operations, Facilities, Fleet, Information Solutions, Security, Customer Care and Health, Safety and Environment.

Along with each allocation, specific 6-year outcomes were identified. The outcomes relevant to Hydro One's Transmission Power Systems allocation are shown in Figure 2 below.

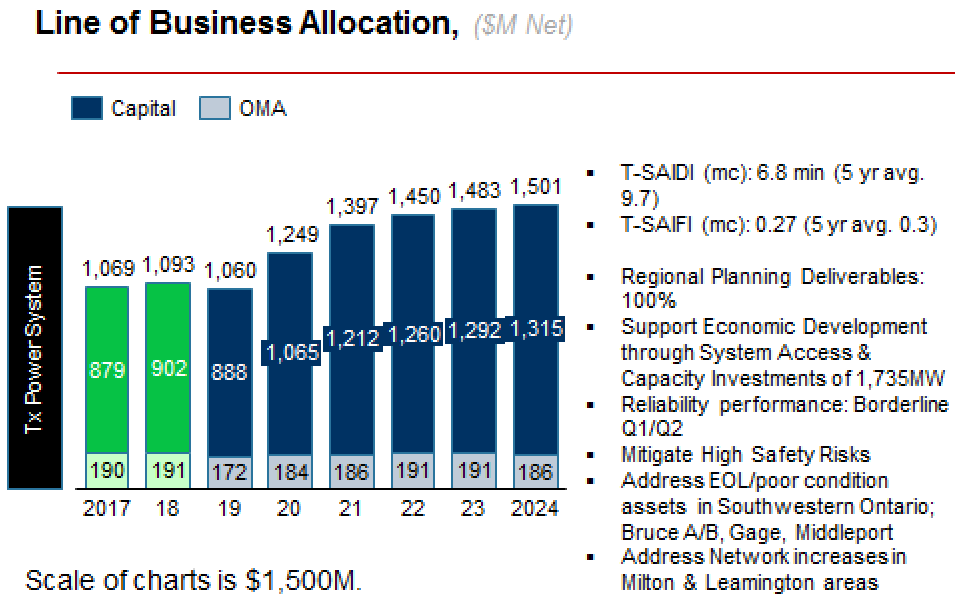

Figure 2 - Transmission Power System Outcomes

In addition to the end-of-plan outcomes, near-term, 1-year outcome metrics were identified, as outlined in Table 1 below. 1-year metrics were developed at the beginning of the Investment Planning Process and subsequently revised based on the approved plan, to form the various business unit scorecards that will be used for 2019. The establishment of interim targets supports the overall approach to long-term target setting and monitoring, ensuring that the long-term targets have updated targets annually.

Table 1 - Historical Capital Expenditure Summary

OEB Category	Historical (Previous Plan and Actual)											
	2015			2016			2017			2018		
	Actual	Plan	Var	Actual	Plan	Var	Actual	Plan	Var	Actual	Plan	Var
	$M	$M	%	$M	$M	%	$M	$M	%	$M	$M	%
System Access	7.6	19.7	-61%	17.0	31.9	-47%	42.7	33.3	28%	33.7	24.3	39%
System Renewal	688.9	573.6	20%	733.9	539.9	36%	740.7	733.7	1%	776.2	780.4	-1%
System Service	157.9	189.9	-17%	140.9	180.0	-22%	93.5	97.0	-4%	73.9	75.6	-2%
General Plant	88.6	116.3	-24%	94.8	114.6	-17%	76.9	86.0	-11%	83.6	119.7	-30%
Total	**943.0**	**899.4**	**5%**	**986.7**	**866.3**	**14%**	**953.9**	**950.0**	0%	**967.3**	**1,000.0**	-3%
System OM&A[1]	441.6	431.2	2%	408.1	436.8	-7%	385.0	397.7	-3%	419.2	394.3	6%

[1] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the Revenue Cap Index identified in Exhibit A, Tab 4, Schedule 1.

Table 2 - Bridge Year and Test Year Capital Expenditure Summary

OEB Category	Bridge	Forecast				
	2019	2020	2021	2022	2023	2024
	F/Cast	Test	Test	Test	Plan	Plan
	$M	$M	$M	$M	$M	$M
System Access	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder	0.0	-17.0	-39.0	-61.0	-78.0	-91.0
Directive[2]	**-0.3**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.4**
Total	**1,038.2**	**1,192.2**	**1,317.7**	**1,369.6**	**1,369.6**	**1,369.6**
System OM&A[1,3]	**356.5**	**375.8**	*	*	**N/A**	**N/A**

For explanatory notes on Forecast Trends vs. Historical Budgets by Category, please see Section 3.3.2.

For explanatory notes on Plan vs. Actual Variance Trends by Category, please see Section 3.3.3.

For explanatory notes on System OM&A, please see Exhibit F.

[2] The Directive adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

[3] Includes the Directive adjustment. Refer to Exhibit F, Tab 1, Schedule 1 for further details.

Table 1 - Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Productivity						
Progressive Operations (Defined Capital)	6	12	12	10	10	49
Progressive Operations (Undefined Capital)	11	27	49	68	81	237
Progressive Productivity Placeholder	17	39	61	78	91	286

As noted in the table above, Hydro One has identified savings opportunities totalling approximately $704M over the 2020-2024 TSP period. This reflects Tier 1 Productivity savings only. There are $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings. This latter category of savings falls within “Progressive Productivity”. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB’s decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned

UNDERTAKING - JT 2.28

Reference:
SEC-026

Undertaking:
Regarding SEC 26, to consider if further level of details can be provided beyond what is currently provided in evidence regarding the base number for each one of the initiatives.

Response:
Please see Attachment 1 to this Exhibit.

Witness: Joel Jodoin

	Category	Initiative Grouping	Measurement and Expected Benefit	Updated Savings 2016A	2017A	2018A	2019	2020	2021	2022	2023	2024	Baseline
Capital	Operations	Engineering	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Engineering through the implementation of EDM software enhancements*	$ -	$ -	$ -	$ 0.4	$ 0.9	$ 1.1	$ 1.4	$ 1.4	$ 1.4	129 Tx FTEs (2017 actual) in records and drafting job functions.
Capital	Operations	Fleet Telematics and Right-Sizing	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ -	$ 1.9	$ 10.2	$ 10.6	$ 11.0	$ 11.1	$ 11.4	$ 11.6	$ 11.3	Baseline is $59.7M annual spend (HONI Total). See EB-2017-0049 Exhibit J 2.3 for detailed methodology
Capital	Operations	Transmission and Stations	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence*	$ -	$ 1.8	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	Savings Calculated per occurance for TWHQ (varies by zone - approx. $185). Baseline for Transmission and Stations efficiencies (BGIS Outsourcing)is 650k.
Capital	Operations	OT Reductions	Overtime Reductions *Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline*	$ -	$ 1.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	Savings calculated against 2015 baseline of 12.3% OT as a % of Base Hours - please refer to I-07-SEC-25
Capital	Operations	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 1.2	$ 12.8	$ 27.9	$ 25.1	$ 30.3	$ 34.9	$ 35.8	$ 35.7	$ 37.1	Calculation described in EB-2017-0049 Exhibit J 2.3. As there are tens of thousands of materials being tracked (automated system reports) Hydro One is unable to reasonably provide the baseline price for each item.
Capital	Operations	Progressive Defined	Targeted Efficiencies - Defined *Efficiencies that have been allocated to specific Operating initiatives that are not yet proven. Allocations taken in Business Plan based on preliminary estimates. Ex - Hydro Vac reduction, Temp Access Roads*	$ -	$ -	$ -	$ 5.0	$ 6.1	$ 11.6	$ 11.6	$ 10.1	$ 10.1	Refer to JT 1.09 for an Update on Progressive initiatives.
Capital	Operations	Progressive Undefined	Targeted Efficiencies - Undefined *Escalating commitment of 1-3% of capital work program to be allocated to future initiatives as they are defined. Included as a Top Line capital reduction*	$ -	$ -	$ -	$ -	$ 10.9	$ 27.4	$ 49.4	$ 67.9	$ 80.9	N/A
Capital	Operations	Scheduling Tool	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements*	$ -	$ -	$ 0.2	$ 0.9	$ 0.9	$ 0.9	$ 0.9	$ 0.9	$ 0.9	32 Tx FTEs (2017 Actual) in Scheduling job functions
Capital	Operations	Wrench Time	Lower Cost Per Unit of Operation *Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.*	$ -	$ -	$ -	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	Labour efficiency per Task: 2015 Labour Hours Less Estimated Labour Hours for planned orders multiplied by $143 per hour. Due to the volume of orders Hydro One is unable to reasonably provide the baseline price for each Task.
OM&A	Information Technology	Contract Reductions	Cost Reduction Based on Historical Spend *Lower cost resulting from Inergi IT Contract renegotiation. Measured against baseline spend for same scope of work*	$ 2.0	$ 2.3	$ 6.6	$ 6.3	$ 6.4	$ 8.9	$ 9.6	$ 9.6	$ 9.6	Baseline is $65.5M (Total 2015 Actual/2016 Plan)
OM&A	Operations	Engineering	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE and contractor reductions in Engineering through the implementation of PCMIS software enhancements*	$ -	$ -	$ 0.7	$ 0.6	$ 0.6	$ 0.6	$ 0.6	$ 0.6	$ 0.6	Baseline is 13 Non-Regular FTEs (2017 Historical Actual) in P&C functions.
OM&A	Operations	Fleet Telematics and Right-Sizing	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ -	$ 0.5	$ 0.2	$ -	$ -	$ -	$ -	$ -	$ -	There are no savings included in the plan years.
OM&A	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls*	$ -	$ -	$ 1.3	$ 2.1	$ 2.0	$ 3.4	$ 2.0	$ 2.4	$ 1.9	Estimate per occurance for inclement weather @ $85 per hour. Forestry baseline is $1566 per km (2015, escalated for labour inflation)
OM&A	Operations	Transmission and Stations	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence*	$ -	$ 0.8	$ 1.8	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	Savings Calculated per occurance for TWHQ. See above in this table.
OM&A	Operations	Network Operating Efficiencies	Operational Program Efficiencies *Unit cost reduction in completing Load Transfer studies through Network Operating group*	$ -	$ -	$ 0.4	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.0	Baseline is historical program budget of $1.0M
OM&A	Operations	OT Reductions	Overtime Reductions *Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline*	$ -	$ 1.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	See OT reductions within the Capital section above in this table

	Category	Initiative Grouping	Measurement and Expected Benefit	2016A	2017A	2018A	2019	2020	2021	2022	2023	2024	Baseline
				Updated Savings									
		Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions*	1.8	2.9	1.7	0.9	0.8	0.8	0.9	0.8	0.8	See Procurement category within the Capital section above in this table
		Scheduling Tool	Cost Reduction from Software Implementation *Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements*	-	-	0.2	-	-	-	-	-	-	See Scheduling Tool category within the Capital section above in this table
		Wrench Time	Lower Cost Per Unit of Operation *Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.*	-	-	1.5	2.3	2.3	2.3	2.3	2.3	2.3	See Wrench Time category within the Capital section above in this table
CCC	Corporate	Corporate Initiatives	Corporate Cost Initiative *Identified reductions in vacancies and contractor and consulting spending*	2.3	1.2	1.4	20.1	19.1	16.5	13.6	11.3	9.4	Baseline is $303.9M (2019 Prior Plan (2018-2023). Tx is allocated by B&V methodology.
	Operations	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Corporate Allocation)*	0.1	1.8	5.4	2.3	2.3	2.3	2.3	2.3	2.3	Baseline is $0. Savings are quantified as a Early Pay credit (negotiated cost reduction) received from Vendors.
			Total Capital	**1.2**	**18.0**	**39.4**	**43.6**	**61.7**	**88.7**	**112.2**	**129.2**	**143.4**	
			Total OM&A	**3.8**	**8.0**	**14.8**	**14.7**	**14.7**	**18.6**	**17.9**	**18.3**	**17.8**	
			Total Common	**2.3**	**3.1**	**6.8**	**22.4**	**21.5**	**18.8**	**16.0**	**13.6**	**11.7**	
				7.3	**29.1**	**61.0**	**80.8**	**97.9**	**126.1**	**146.1**	**161.1**	**172.9**	

UNDERTAKING – J 2.3

Reference
I-25-Staff-123
K2.1

Undertaking
To provide the detail behind the numbers for the three initiatives move to mobile, procurement, and telematics, as well as the methodology for determining these calculations; and to provide a narrative as to whether or not what we are seeing is the same approach used in other initiatives.

Response
1. Move to Mobile – OM&A and Capital – Background
The Move to Mobile (M2M) solution was initiated to enhance Distribution workflow, with technology (SAP Work Manager with GIS Technology), upgrading our scheduling/dispatch tool (PCAD) and best in class process improvements. It was launched in Zone 3B in February 2017 and after a three-week period (to identify gaps/issues) was deployed across the province. The M2M project went live in the final Distribution Zone on April 24, 2017 and transitioned to sustainment on July 4, 2017.

M2M has two productivity savings components: Field Force Productivity (Capital) and Clerical Staff savings (OM&A).

Clerical Staff
M2M has automated the following:

- Automate creation of some work orders/notifications
- Auto scheduling of work types using improved scheduling technology

Some of this work was previously performed manually. This automation represents a reduction/ elimination of manual data entry.

Field force productivity

M2M has allowed for:

- Improved tools to support work planning, scheduling and dispatching.
- Improved data quality and timeliness
- Reduce re-work (truck rolls) when information is missing or incorrect
- Provide electronic access to documents, design standards and maps
- Allow field to create new asset notifications and clear erroneous system recorded defects

1 **Target Setting Methodology**

M2M Benefit Card Summary ($K)

Benefits were estimated and submitted as part of business case.
Benefit Card values were used to set the budget.

Category	Description	2018	2019	2020	2021	2022	Calculation Assumptions
OM&A	BASC Reduced Data Capture	2,121	2,164	2,207	2,207	2,207	reduction of 21 clerical FTE @ labour rate of $96, 492 PWU 57
OM&A/ Capital	FBC - Optimized Process	858	875	893	893	893	reduction of 8 clerical FTE @ labour rate of $102,456 PWU 58
Capital	Scheduling Optimization	8,196	8,359	8,527	8,527	8,527	5% of 900 FTE @ labour rate $157,844 PWU 01
Capital	Trouble / Outage Updates	765	780	796	796	796	4 calls x 47,504 trouble calls x 2 min@ labour rate $157,844 PWU 01
Capital	Maps & Standards Updates	838	855	872	872	872	map binder updates 90 hrs/ops/year + map issues 48 hrs/ops/year @ labour rate $157,844 PWU 01
Capital	Field - Data Capture	55	56	57	57	57	253 jobs reverified/yr @ 1 hr + 4 material issues/ops per year @ 1 hr @ labour rate $157,844 PWU 01
Capital	Courier and Printing	169	225	225	225	225	25 pages per job folder x 100,000 job folders + 75% of courier costs
Total Savings ($K)		**13,001**	**13,314**	**13,576**	**13,576**	**13,576**	

2

Calculation Methodology

Clerical Staff (OM&A) - Productivity savings are realized through reduced headcount. Baseline headcount is compared to actual headcount on a monthly basis. The change in headcount is quantified using actual labour rates.

Field Force Productivity (Capital) - A baseline of Labour Hours per unit has been quantified using SAP system data. Productivity Savings are calculated using Labor hours saved across the work program and compared to the established baseline. A unit based calculation compares historical labour hours per unit to actual.

2. Procurement Savings – OM&A and Capital – Background

In 2016, Supply Chain performed a comprehensive spend analysis to bundle procurement spend from across the company into natural sourcing categories for all goods and services. An opportunity analysis was conducted on these categories to identify and prioritize key initiatives and go-to-market strategies.

These strategies utilize industry best practices and streamlined processes. Examples of these strategies include; multiple feedback rounds in competitive sourcing events, enhanced direct negotiations for contract extensions and a redesigned sourcing process to make it faster and easier to do business with Hydro One. The opportunity analysis and category strategy developed were used to create a targeted savings percentage for each category.

During the investment planning process, Hydro One applied the targeted savings percentage to its work program by embedding the savings into the category related investment drivers.

Hydro One is unable to release the planned savings targets for categories that have not yet been executed as this would negatively impact Hydro One's ability to effectively negotiate with its suppliers. Below are examples of the target savings for completed sourcing events, including the weighted average savings target that was used to plan the procurement savings from 2018 to 2022.

Category	Target Savings %	Methodology	CAP	OM&A	CCC	2018	2019	2020	2021	2022
Equipment Rentals	7%	Hourly Rate	100%			2.9	3.3	3.5	3.7	3.9
General Contractors	4%	Hourly Rate	100%			1.0	1.1	1.2	1.3	1.3
Electrical Hardware	5%	Unit Cost	100%			3.2	3.8	3.8	4.0	4.1
General Hardware	10%	Unit Cost	70%	30%		0.1	0.1	0.1	0.1	0.1
Volume Rebates*	N/A	Total Rebates			100%	0.7	0.7	0.7	0.7	0.7
Other Categories						7.9	8.2	12.7	11.8	13.4
Total						**15.9**	**17.2**	**21.9**	**21.6**	**23.5**

*Note: volume rebate savings are based on total dollar rebates received on all procurement spend and is not a percentage based target.

<u>Target and Actual Calculation Methodologies</u>

Categories that are services based and charged out on an hourly basis, such as Equipment Rentals and General Contractors, have savings estimates calculated based on the target hourly rate reduction. The target savings are based on all services provided within the category proportionately represented by estimated volume. To track actual savings, the negotiated savings rate (old hourly rate vs. new hourly rate) is multiplied by the actual volume purchased.

Categories for materials and equipment that have unit counts, such as Electrical Hardware and General Hardware, have savings estimates calculated based on the target unit cost reduction. The target savings are calculated by considering all units within the category proportionately represented by estimated volume. To track actual savings, the negotiated savings rate (old unit cost v.s new unit cost) is multiplied by the actual volume purchased.

An example of our corporate common cost savings are the Volume Rebates that Hydro One receives from suppliers from negotiated contracts. Not all contracts have volume rebates built into them and the target savings is based on a total dollar figure and not a percentage. Savings are tracked throughout the year based on actual credit notes or cash received.

3. Telematics – OM&A - Background

As a further safety initiative, Fleet Services has implemented Telematics Technology across the transport and work equipment in Hydro One. Telematics is an integrated use of telecommunications, including Global Positioning Systems (GPS) and informatics systems, which provide location of vehicles and live data. The benefits of telematics include:

- Provides insight to driving behaviours which allows us to reinforce road safety
- Allows for real-time management of corporate assets
- Provides solutions that allow operators to become more efficient and allows management to exercise better control of equipment
- Provides solutions to allow for driver behavior modification

The telematics initiative is one of the most significant initiatives underway in Fleet Services. The project was completed at the end of 2016 with a total of ~4,800 telematics units installed across various T&WE (Transport and Work Equipment) asset categories. The technology provides data that allows us to realize efficiencies in T&WE use, resulting in optimal usage of the assets. Some of the key metrics being tracked are fleet utilization, speeding, harsh driving, idling, PTO (power take-off) usage and fuel efficiency.

Target Setting Calculation

Reduction in Net Fleet Complement	2018	2019	2020	2021	2022
Light duty vehicles	*32*	*32*	*64*	*64*	*129*
Misc. (Chippers, Manlifts, Forklifts, etc)	*14*	*14*	*16*	*28*	*72*
Total	***46***	***46***	***80***	***92***	***201***

Reduction of 10% of Light duty and 5% of other specialized equipment as per the Telematics Business Case

Reduction in Fleet OM&A Requirement	2018	2019	2020	2021	2022
Fuel Savings Estimate Preliminary Estimate	*$0.5*	*$0.5*	*$0.5*	*$0.5*	*$0.0*
Maint. Savings $16k per unit estimate	*$0.7*	*$0.7*	*$1.3*	*$1.5*	*$3.2*
Extending life of parts replacement	*$0.0*	*$0.0*	*$0.3*	*$0.0*	*$0.0*
Total	***$1.2***	***$1.2***	***$2.1***	***$2.0***	***$3.2***
Allocation to Distribution (67%)	***0.8***	***0.8***	***1.4***	***1.3***	***2.2***

Assumptions
OM&A Savings: Blended avg. maintenance cost per unit for Light and Misc. vehicles (Annual) = $16,000
Savings anticipated from Fuel Savings in Speeding & Harsh event reduction - $500K/year (Based on 2017 estimate), due to Driver behavior modification
Additional one-time saving of $300K for maintenance through optimizing asset maintenance efficiency/extending life of parts replacement

Notes:

The table above represents the original savings targets.
In 2017 all committed savings were allocated to 'Fuel Savings Estimate' to correspond with approved tracking methodology.

Calculation Methodology - 2018

Encompassing all of Hydro One's vehicles across the province, savings are achieved through rationalization and improvement in driver behavior via the use of telematics to determine areas of consolidation and reduction of overall footprint. Savings are calculated as:

$$Savings = \left[\left(\frac{B}{A}\right) - C\right] \times D$$

Where:

A: Average kilometers per litre of fuel for 2016 (used as baseline year)
B: Total kilometers in 2018
C: Total litres of fuel in 2018
D: Average 2018 fuel cost per liter from ARI Reports[1]

Telematics - Capital - Background

The Fleet Right-Sizing Initiative leverages telematics data to identify all underutilized vehicles and remove all excess vehicles from service. The equipment complement has been reduced by 10% in 2017 and will be maintained at the new optimal level going forward. The goal is to have the right equipment and the right number of equipment to successfully execute the work programs and satisfy all customer staffing requirements.

[1] Data provided by ARI Global Feet Management Services, ARI Fleet Management System and Fuel Reports

<u>Target Setting Methodology</u>

	2018	2019	2020	2021	2022
Baseline	59.70	59.70	59.70	59.70	59.70
Updated Business Plan	39.72	44.59	45.10	45.41	45.76
Savings	**19.98**	**15.11**	**14.60**	**14.29**	**13.94**
Savings allocated to Distribution (67%)	**13.4**	**10.1**	**9.8**	**9.6**	**9.3**
Baseline Replacement Units	805	805	805	805	805
New Plan Units	503	473	473	473	473
New Plan Cost/unit	0.079	0.094	0.095	0.096	0.097
Baseline Cost/Unit	0.074	0.074	0.074	0.074	0.074

<u>Calculation Methodology</u>

Baseline capital replacement plan (monthly) is compared to actual Capital replacement. The variance to baseline in actual units and actual cost per unit is quantified to determine savings.

<u>Other Initiatives</u>

A similar framework is used when setting the anticipated targets and determining a calculation methodology for quantifying the benefits of the other initiatives.

OEB INTERROGATORY #136

Reference:

EB-2018-0098, Exh B/Tab 7/Sch 1/p.1, Table 1

Interrogatory:

a) The original cost estimate for the "10 MVAr reactive support" project component was $4 million. What is the current estimate for this component?

b) The original cost estimate for the "10 MVAr capacitive support" project component was $2 million. What is the current estimate for that component?

c) What was the initial estimate quality associated with each of these components, using the AACE estimate classification system and also expressed in terms of +/- percentage range?

d) What is the present estimate quality for each of these components using the same system?

e) Does the updated estimate include other incremental substation components that cannot be classified as either reactive support or capacitive support and cannot be attributed prorata to either of those primary project components? Please provide details of all such unattributed project components and explain why they are now required to satisfy the IESO's functional specifications for the KAR project.

f) Did Hydro One inform the OEB of the initial estimate quality and range when the LTC application was submitted?

g) Did Hydro One inform the OEB of the present estimate quality and range when submitting the revised cost estimates in March 2019?

h) Please provide a detailed description of all site-specific and non-site-specific factors that were considered when Hydro One developed the initial reactive and capacitive support project component estimates.

i) What new information became available following the initial LTC application regarding each of these project components that informed the cost variances identified in the revised estimates filed with the OEB in March 2019?

j) What additional design and procurement work has been done between the time the initial LTC application was submitted and the issuance of the revised cost estimate?

k) Has project scope changed since the initial cost estimate?
   i. If yes, what triggered the scope change?
   ii. If yes, were all changes authorized through Hydro One's project management process?

l) What are the detailed drivers that caused the variance between the initial and revised cost estimates?

m) Did Hydro One originally estimate the substation component additions as if this was a greenfield project, or was the initial estimate developed with the understanding that this is a brownfield renovation-type project?

n) Would Hydro One consider it to be good utility practice to develop a brownfield construction estimate using greenfield construction site assumptions?

o) Did Hydro One apply the same level of estimate diligence and expertise to estimating costs for the substation components as it applied to estimating the line component costs? If no, please explain why not.

p) What would Hydro One do differently in preparing and submitting a Leave to Construct application for a similar facility today?

<u>Response:</u>

a) The current Class 3 cost estimate provided to the OEB in March 2019 was $17.3 million and included the installation of both reactor and capacitor bank. Individual cost estimates for reactive and capacitive devices were not prepared as both devices were required.

b) Please see response to part (a) above.

c) As documented in the LTC Application for this Project, the initial estimate quality of the station component of this investment was referenced as being preliminary in nature, and made no reference to an AACE or accuracy range.

d) The current estimate quality for the station component is AACE Class 3 with an accuracy of -20% to +30%.

e) The current estimate provided to the OEB in March 2019 does not include incremental facilities or substation components beyond those required to meet IESO requirements.

f) Please see response to part (c) above.

g) In the March 2019 letter the OEB was informed that, "*detailed estimating and field verification has unearthed the need for increased scope of work to accommodate the new reactive facilities beyond what would normally be expected in a project of this scale*." Hydro One's *detailed estimate* terminology refers to AACE Class 3 estimates (-20% to +30%).

h) At the time of preparing the initial estimate, there were no site specific factors anticipated. The non-site specific factor related to the installation of shunt capacitor bank and reactor.

i) In the March 2019 letter to the OEB, details were provided on the new information that resulted in the cost variances. As noted in the letter, "*detailed estimating and field verification has unearthed the need for increased scope of work to accommodate the new reactive facilities beyond what would normally be expected in a project of this scale. Site specific conditions led to increased scope in the following areas: relocation of the existing low voltage capacitor bank, extension of the control building, increased grounding required, and increased cable trench / civil work.*"

j) Between the initial estimate and revised cost notification to the OEB, design work necessary to prepare detailed estimates was carried out. There were no procurement activities during this time.

k) Project scope for both the line and station remains unchanged and in line with IESOs requirements.

Witness: Robert Reinmuller, Bruno Jesus, Donna Jablonsky

l) Please see response to part (i) above.

m) Hydro One developed the initial estimate with the understanding that Kapuskasing TS is an existing station but will have new facilities installed within the existing site.

n) Hydro One does not classify estimates as brownfield or greenfield. Estimates are developed based on the purpose required. Initial estimates would be of a preliminary or budgetary type and are developed based on a high level review of the site, review of cost of similar project, and input from staff. These estimates would be refined and accuracy improved as further detailed engineering is done and more information becomes known.

o) At the time of LTC Application, the line work was a detailed estimate, and station work estimate was preliminary in nature. The LTC Application was filed with the information available at the time due to the timing of the project to ensure sufficient time for the line work to be executed in order to satisfy the IESO's requested in-service date.

p) Hydro One would endeavor to submit detailed estimates as part of its LTC Application, provided that sufficient time is available between the IESO request and the specific need date.

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Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

March 18, 2019

Ms. Nancy Marconi
Manager, Supply and Infrastructure Applications
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

EB-2018-0098 – Hydro One Networks Inc.'s Section 92 - Kapuskasing Area Reinforcement Project – Project Update

In accordance with the Decision and Order in the aforementioned proceeding, Hydro One Networks Inc. ("Hydro One") is writing to inform the OEB of a change in the in-service date and cost of the Kapuskasing Area Reinforcement Project ("KAR Project" or "the Project").

As documented in Exhibit B, Tab 3, Schedule 1 of the prefiled evidence, the station cost component of the KAR Project was in the budgetary estimating phase of a project lifecycle. Since the leave to construct approval of the Project, detailed estimating and field verification has unearthed the need for increased scope of work to accommodate the new reactive facilities beyond what would normally be expected in a project of this scale.

Site specific conditions led to increased scope in the following areas:

- Relocation of the existing low voltage capacitor bank
- Extension of the control building
- Increased grounding required
- Increased cable trench / civil work

Hydro One has confirmed the design has not been overbuilt nor does it accommodate work outside of the direct scope documented in the IESO need evidence for the leave to construct application provided at Exhibit B, Tab 3, Schedule 1, Attachment 1 of the Application.

As a result of the increased station scope, the overall project cost estimate, provided at Exhibit B, Tab 7, Schedule 1 of the prefiled evidence, of approximately $21.07M ($15.07M in lines costs and $6M in station costs) has increased. The new estimate to complete the project is approximately $32.1M ($14.8M in lines costs and $17.3M in station costs). The breakdown of this cost, in a manner analogous to that originally provided in Exhibit B, Tab 7, Schedule 1 of the prefiled evidence is provided as Attachment 1 of this correspondence. Additionally, as a result of the increased scope, the schedule for the Project originally provided in Exhibit B, Tab 11, Schedule 1, has also been revised. The updated schedule is provided as Attachment 2 of this correspondence and results in a five month delay in the in-service of the H9K line.

Hydro One has circled back with the IESO to confirm that the installation of a capacitor bank and reactor remains the preferred solution and, as Hydro One understands, the IESO maintains this position.

If you have any further questions or concerns, please contact Pasquale Catalano via email at regulatory@Hydroone.com or by phone at 416-345-5405.

An electronic copy of this correspondence has been filed through the Ontario Energy Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Attach.

Attachment 1

Table 1: Project Cost

	Estimated Cost ($000's)
Materials	3,059
Labour	5,389
Equipment Rental & Contractor Costs	3,400
Sundry	400
Contingencies	700
Overhead [1]	1,534
Allowance for Funds Used During Construction [2]	334
Total Line Work	**$14,816**
Materials	2,962
Labour	5,718
Equipment Rental & Contractor Costs	4,208
Sundry	450
Contingencies	1,498
Overhead [3]	1,725
Allowance for Funds Used During Construction [4]	783
Total Station Work	**$17,344**
TOTAL PROJECT WORK	**$32,160**

[1] Overhead costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[2] Capitalized interest (or AFUDC) is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and carrying forward closing balance from the preceding month.

[3] Overhead costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[4] Capitalized interest (or AFUDC) is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and carrying forward closing balance from the preceding month.

Attachment 2

TASK	START	FINISH
Submit Section 92		February 2018
Projected Section 92 Approval		August 30, 2018
LINES		
Detailed Engineering	March 2018	May 2019
Procurement	July 2018	June 2019
Receive Material	September 2018	June 2019
Construction	June 2019	March 2020
IN SERVICE		**24 March 2020**
STATIONS		
Detailed Engineering	November 2018	November 2019
Procurement	May 2019	November 2019
Receive Material	June 2019	March 2020
Construction	May 2019	January 2021
IN SERVICE		**21 January 2021**