EB-2017-0049

Hydro One Networks Inc.

2018-2022 Distribution Rates Application

AMPCO Compendium

Panel #5 – Asset Management Planning & Work Execution

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2018 net income by approximately $23 million and its distribution business' 2018 net income by approximately $15 million. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with First Nations and Métis communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

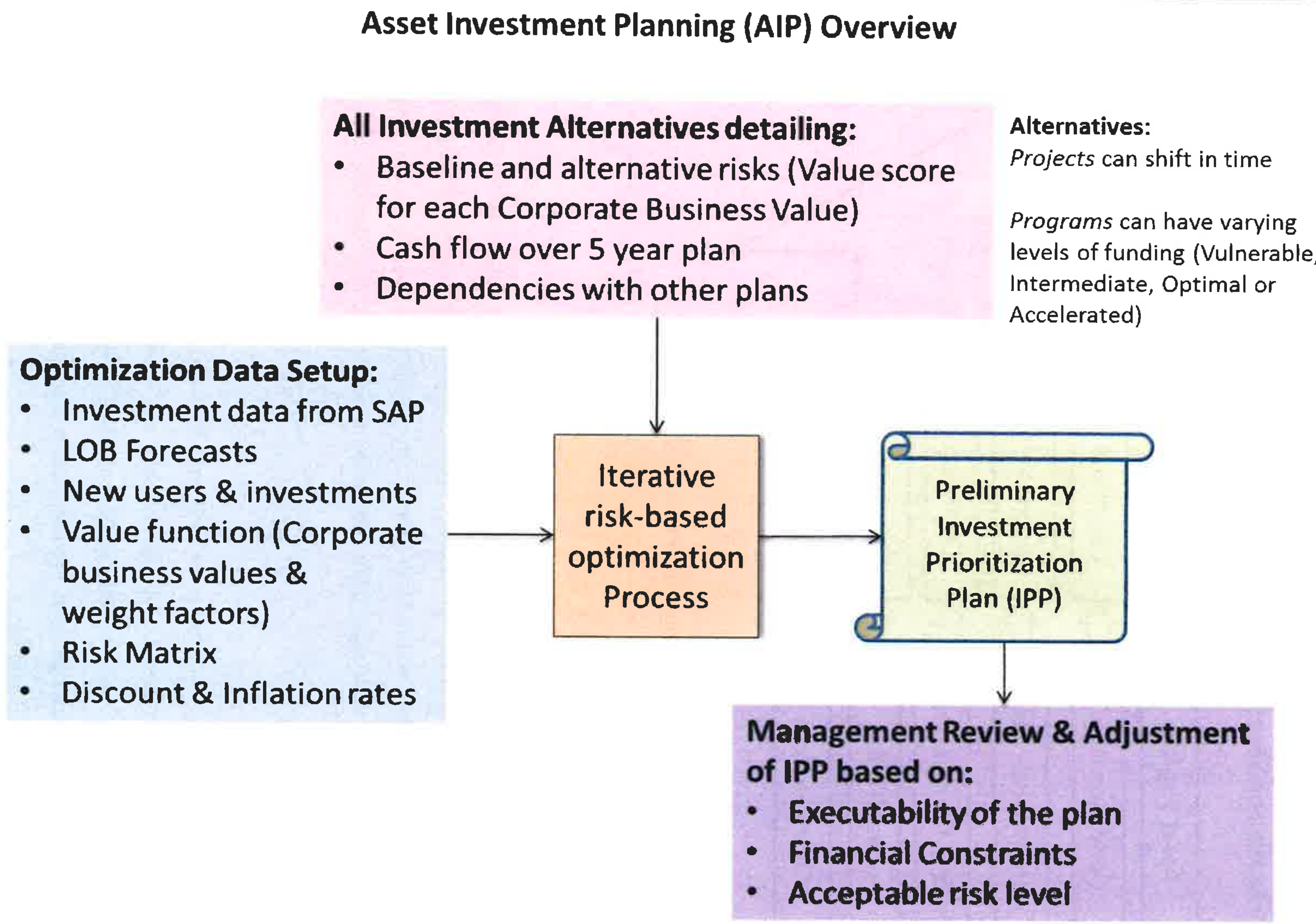
The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

1

ASSET INVESTMENT PLANNING (AIP) OVERVIEW



Prepared by Internal Audit
For audit report purposes only

2

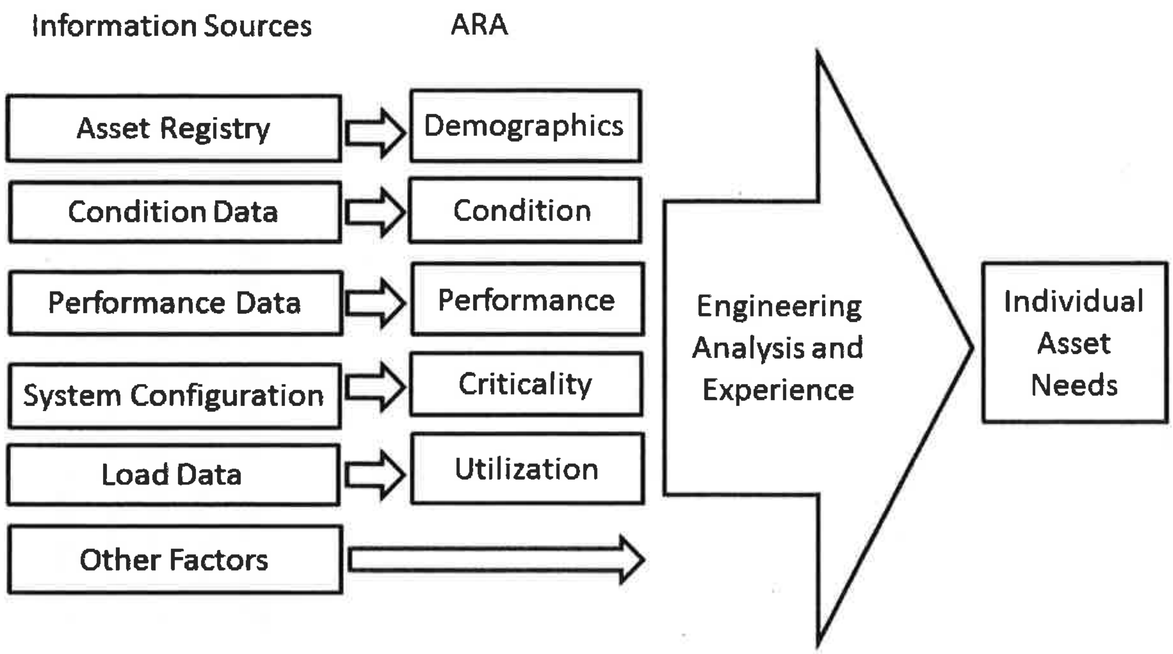


Figure 10 - Asset Need Development Process

Asset Demographic Risk

Asset demographic risk relates to the increased probability of failure exhibited by assets of a particular make, manufacturer, and/or vintage. Asset demographic data by make and manufacturer is contained within Hydro One's asset registry. Typically, the probability of asset failure increases with age. Thus, the asset demographic risk increases as an asset ages.

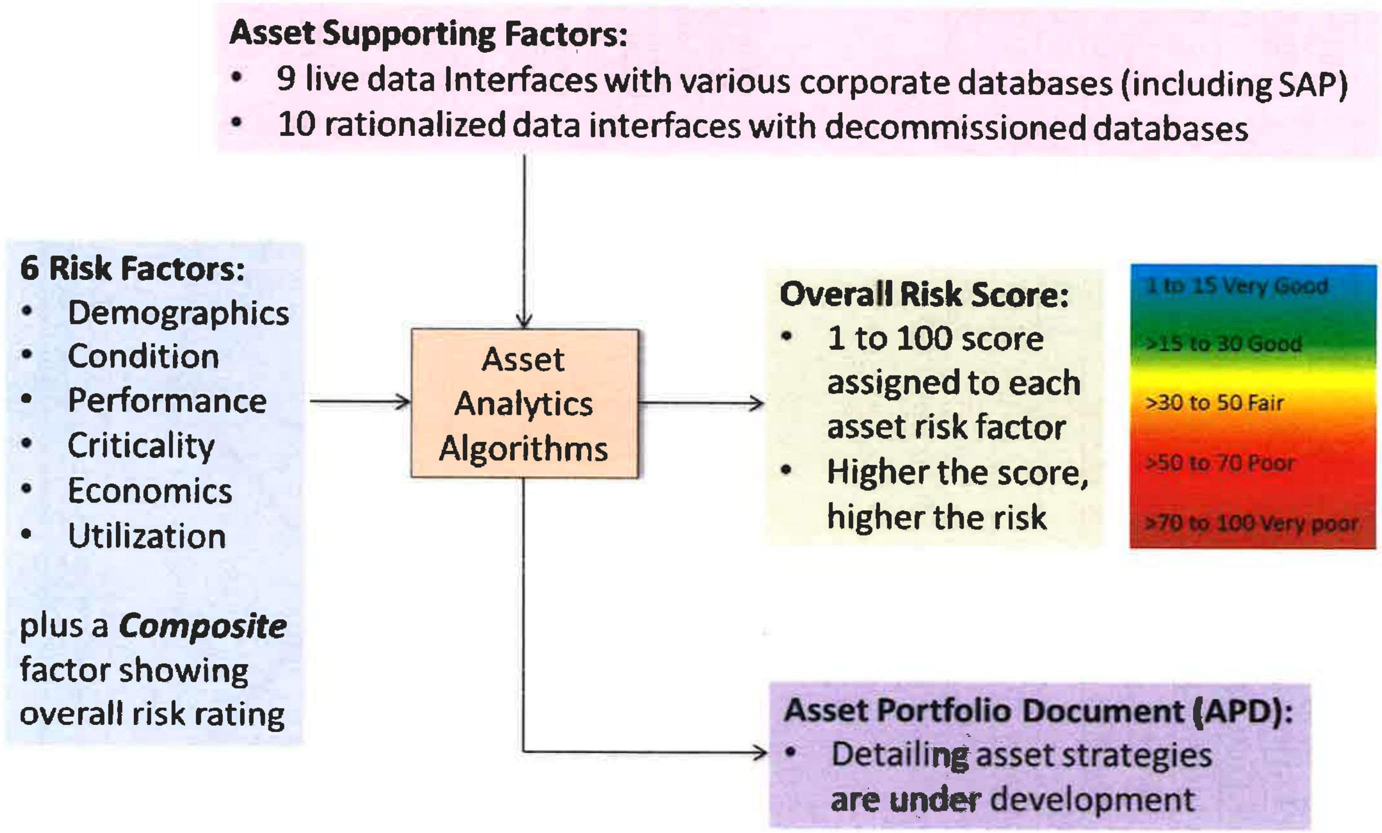
At times, specific asset makes or models are observed to deteriorate at a markedly different rate than other assets of the same type. For example, Hydro One has observed increased deterioration rates in Red Pine wood poles of specific vintages. Poles of this material and of these specific ages therefore carry a higher asset demographic risk than other wood poles of the same age.

Witness: Darlene Bradley

3

ASSET ANALYTICS (AA) OVERVIEW

Asset Analytics (AA) Overview



Prepared by Internal Audit
For audit report purposes only

Table 13 - SAIDI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.03	0.01	0.00	0.02	0.03
Defective Equipment	2.57	6.59	3.03	3.55	3.00
Foreign Interference	0.44	0.46	0.44	0.40	0.41
Human Element	0.04	0.11	0.08	0.08	0.05
Loss of Supply	0.72	0.96	0.56	0.72	0.61
Scheduled	1.41	1.53	1.48	1.43	1.48
Tree Contacts	4.24	14.67	3.36	5.53	6.17
Unknown/Other	1.84	3.09	0.96	1.20	1.43

Includes outages due to Loss of Supply and Force Majuere

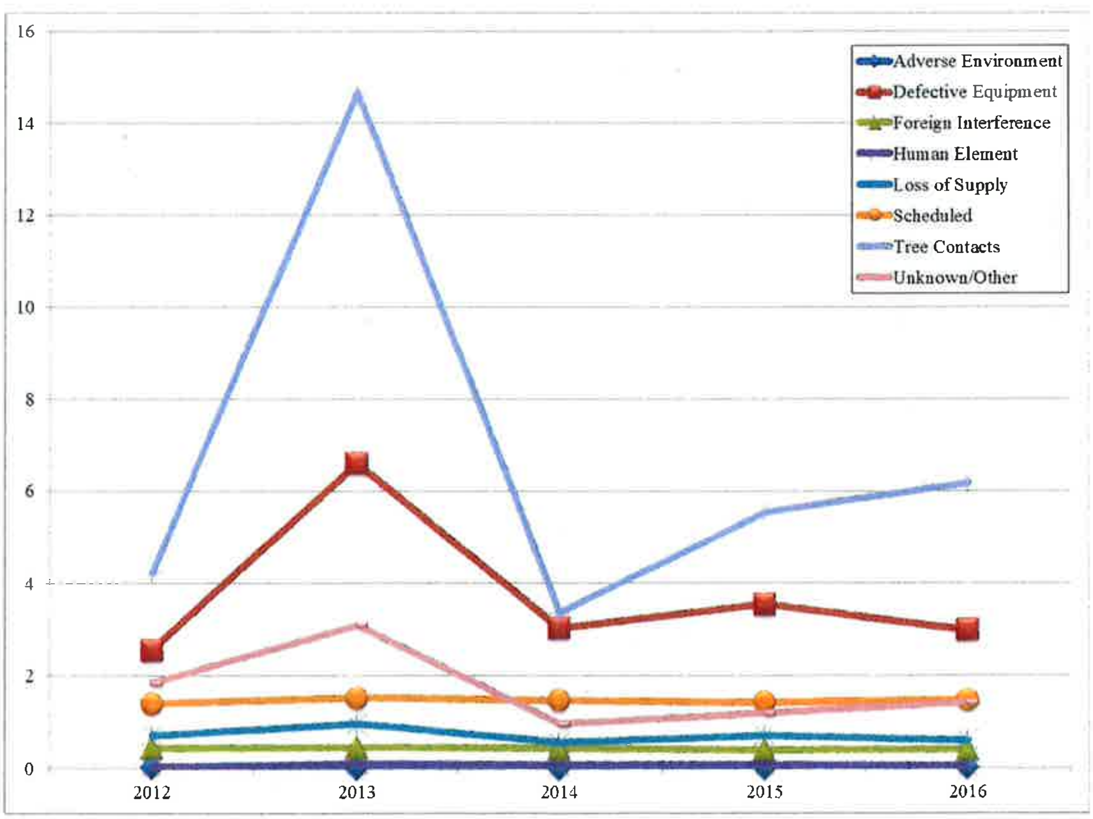


Figure 6 - Chart of SAIDI by Outage Cause

Witness: Michael Vels/Greg Kiraly/Darlene Bradley challenged planners to continue to investigate a plan that would further mitigate cost increases but still reflect responsible stewardship of the assets and no degradation in reliability over the full Term. In particular, managers were challenged to consider how to mitigate the significant rate increase in 2018.

As a result, an adjusted investment portfolio with a forecasted 2018 rate impact of 5.4%, "Plan B – Modified", was developed that would maintain overall forecasted system reliability at current levels, while continuing to offer discrete power quality and reliability improvements for certain segments of the network. Tables 4 and 5 summarize the assumptions that defined Plans A, B, C and B - Modified.

Table 4: SAIDI Projection for Investment Plan Options

SAIDI[1]:	Avg. 2013-15: 7.3 hours/year	Average Number of Hours that a Customer is Interrupted					
	Assumptions			Forecasted Impact on SAIDI [2]			
	Failure Rate/Impact	Contribution to SAIDI	SAIDI Contribution (based on 2013-15)	Plan A	Plan B	Plan C	Plan B-M
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%	8%
Estimated Impact to SAIDI				**6%**	**3%**	**(2)%**	**0%**
Forecasted SAIDI (hours)				**6.9**	**7.1**	**7.4**	**7.3**

Exhibit Reference: B1-1-1

1- *Excludes force majeure and loss of supply events*

2 – *These columns reflect the forecasted impact on SAIDI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.*

Table 5: SAIFI Projection for Investment Plan Options

SAIFI [1]:	Avg. 2013-15: 2.6 outages/year	Average Number of Times a Customer is Interrupted					
	Assumptions			Forecasted Impact on SAIFI[2]			
	Failure Rate/Impact	Contribution to SAIFI	SAIFI Contribution (based on 2013-15)	Plan A	Plan B	Plan C	Plan B-M
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.6**	**2.6**

Exhibit Reference: B1-1-1

1-Excludes force majeure and loss of supply events

2 – These columns reflect the forecasted impact on SAIFI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.

Plan B - Modified included the following adjustments compared to original Plan B:

- A deferral of some 2018 capital spending on wood pole replacements, station refurbishments, component replacements, system capability reinforcement, information technology and facilities and real estate to minimize rate impacts and offset the effects of a reduced load forecast, accepting short-term, small-scale reliability impacts where appropriate;
- The acceleration of productivity initiatives to reduce unit and operational costs and associated rate impacts, which are described in Section 1.5 of the DSP and summarized in Table 6 of this Exhibit;
- To sustain reliability, continued investment in certain System Renewal projects and programs based on asset condition and poor performance; and
- The establishment of OM&A and capital programs to investigate power quality issues, install power quality meters and surge arresters, and improve grounding where needed.

These initiatives reduced the total Term projected capital expenditures by $51 million or approximately 7.5% when compared to original Plan B.

Witness: Oded Hubert

7

The following two figures illustrate Hydro One's reliability performance over the 2010 to 2013 period. Note that an event is considered *force majeure* when it impacts more that 10% of customers served by Hydro One.

Figure 4: Yearly SAIDI Performance

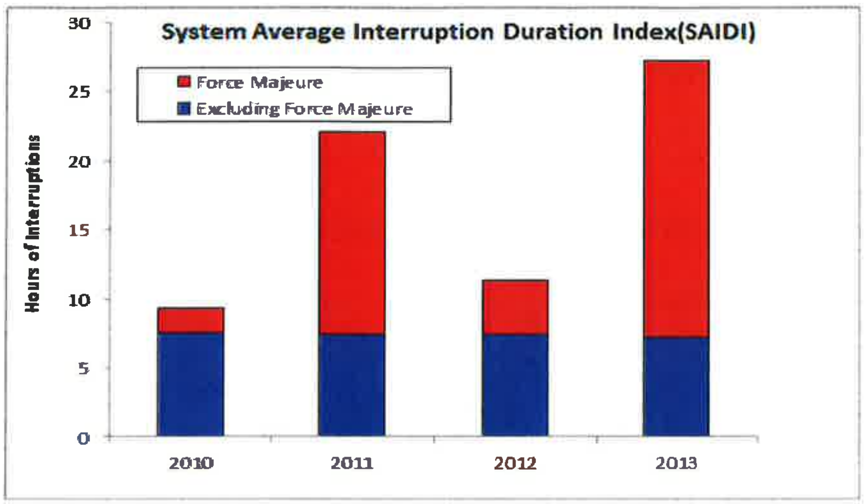
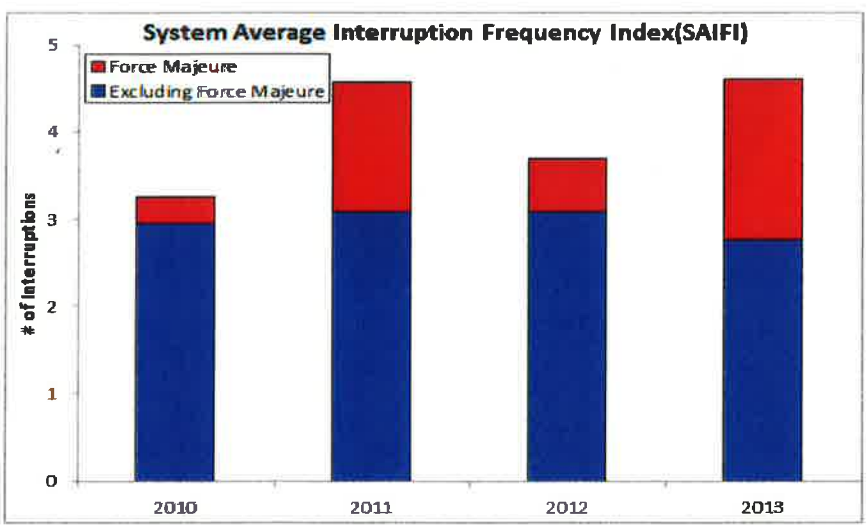


Figure 5: Yearly SAIFI Performance

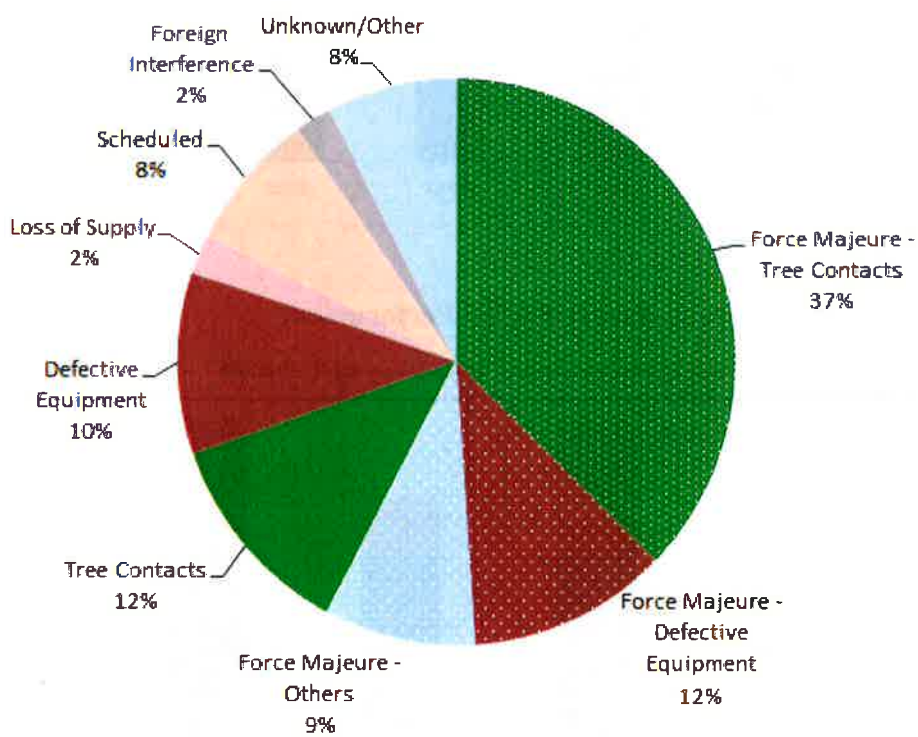


8

Excluding *force majeure* events, performance for SAIDI and SAIFI has remained relatively consistent during the 2010 to 2013 period. Including *force majeure* events, performance has varied significantly from year to year due to variations in the number and severity of storms that have affected the Hydro One distribution system in a given year.

Figure 6 below illustrates the factors that contributed to the SAIDI performance over the 2010 to 2013 period.

Figure 6: Contributions to SAIDI - Four Year Average 2010 – 2013

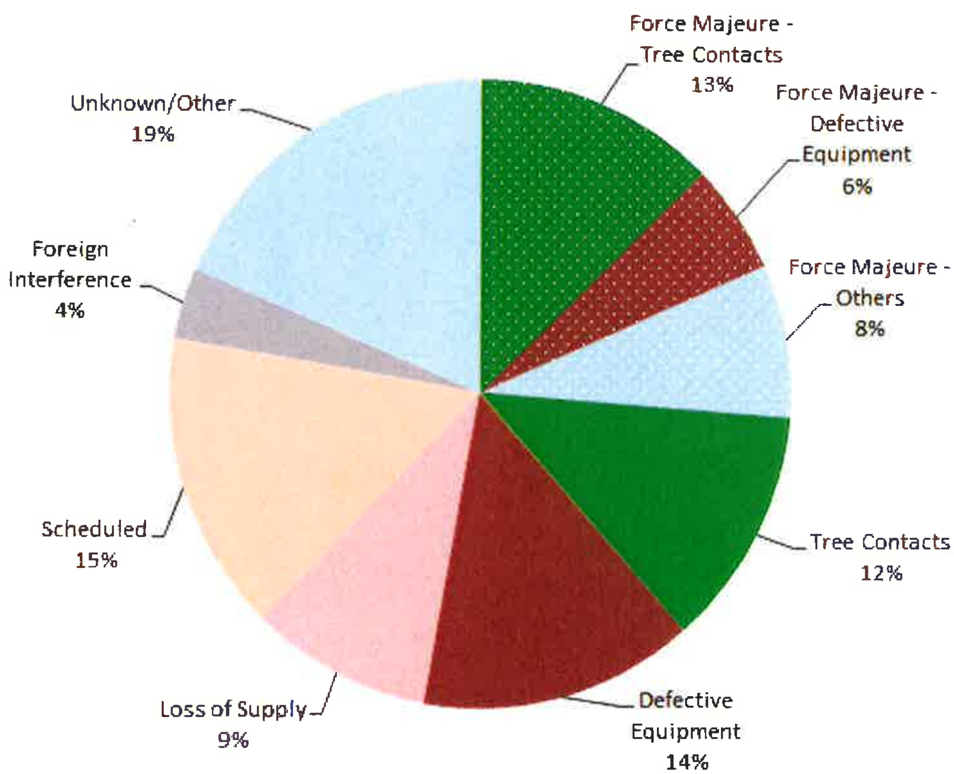


Outages attributed *to force majeure* events (e.g. high winds, ice or snow) contributed to 58% of SAIDI. With a focus on specific causes, it is noted that tree contacts account for

49% of total SAIDI (37% *force majeure* and a further 12% excluding *force majeure*). The next largest contributor to SAIDI was defective equipment at 22% (12% *force majeure* and a further 10% excluding *force majeure*).

Figure 7 below illustrates the factors that contributed to the SAIFI performance over the 2010 to 2013 period.

Figure 7: Contributions to SAIFI - Four Year Average 2010 – 2013



Tree contact was the main contributor to SAIFI totaling 25% (i.e. 13% *force majeure* and a further 12% excluding *force majeure*). The other significant contributor was defective equipment at 20% (i.e. 6% *force majeure* and a further 14% excluding *force majeure*).

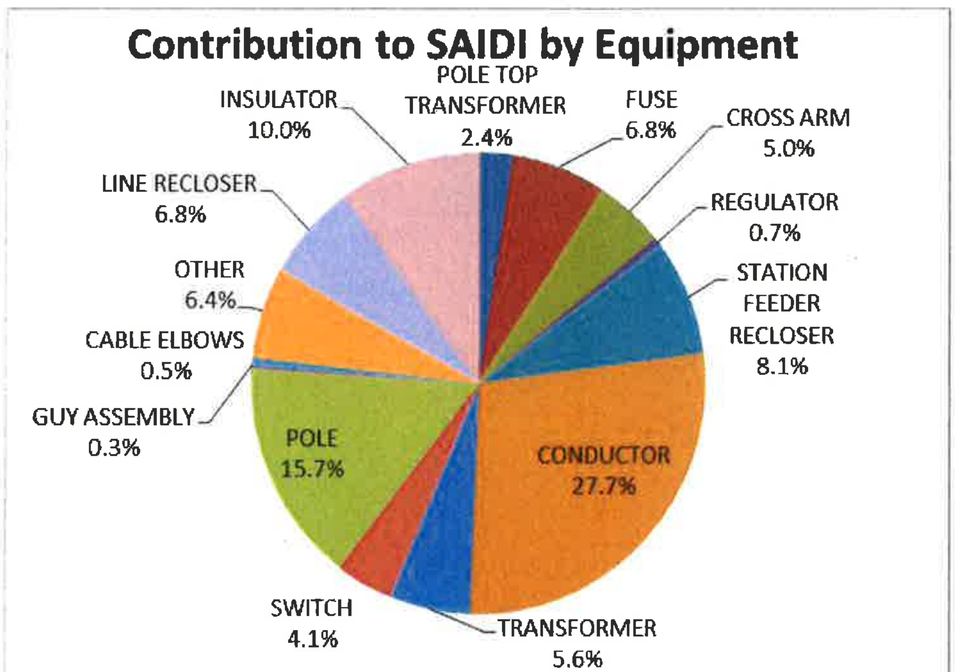
<u>*UNDERTAKING - TCJ1.05*</u>

<u>*Undertaking*</u>

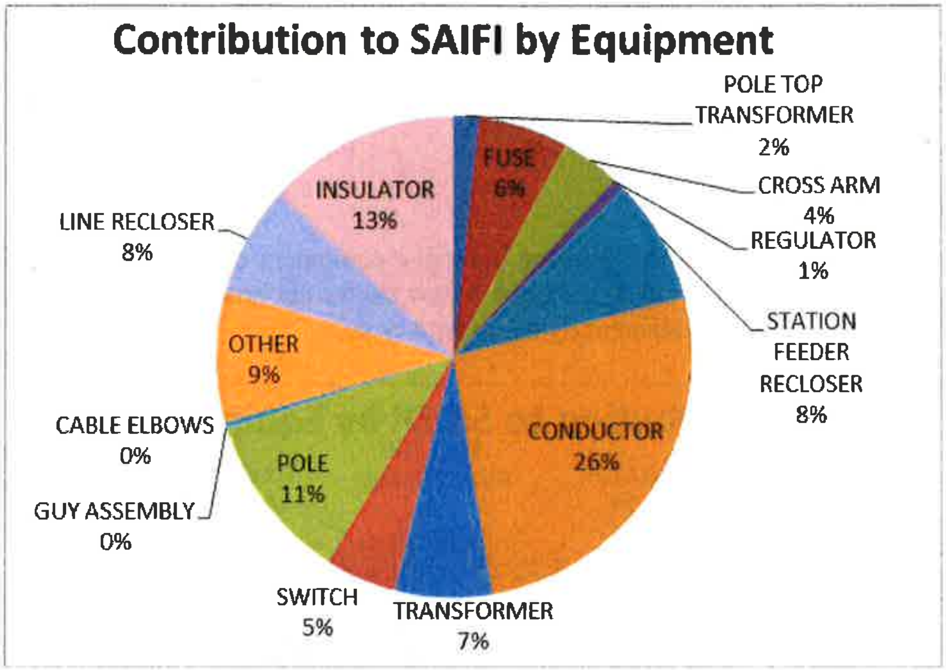
To provide a breakdown of the 10 percent of defective equipment that contributes to SAIDI, by equipment type, and a breakdown of the 14 percent defective equipment that contributes to SAIFI, by equipment type.

<u>*Response*</u>

In response to the question regarding defective equipment cited in Exhibit I, Tab 2.02, Schedule 14 AMPCO 4 and 5, the chart below shows the breakdown of the contribution to SAIDI of defective equipment by equipment type.



The chart below shows the breakdown of the contribution to SAIFI of defective equipment by equipment type.



Association of Major Power Consumers in Ontario Interrogatory # 23

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 2.3 Asset Condition

Interrogatory:

a) Please complete the attached excel spreadsheet.

b) Please provide a live excel version of the completed spreadsheet.

c) Please identify the asset groups where the data availability index is below 100%.

d) Please identify the asset groups where the asset condition data gaps are moderate.

e) Please identify the asset groups where the asset condition data gaps are high.

f) Please identify the asset groups where Hydro One does not have any condition data.

g) Please identify the asset groups where asset age is the predominant factor in determining condition.

Response:

a) Please refer to Attachment 1 to this response.

b) Please refer to Attachment 1 to this response.

c) With consideration to the vast population of distribution station and lines assets, most asset groups have data availability levels below 100%.

d) Hydro One has not defined "moderate" asset condition data gaps.

e) Hydro One has not defined "high" asset condition data gaps.

Witness: GARZOUZI Lyla

f) There are no asset groups for which Hydro One does not have any condition data. However as noted in Attachment 1 not all asset types or sub-types have condition algorithms.

g) There are no asset groups for which asset age is the predominant factor in determining condition.

D24-AMPCO-23
Ref: B1-1-1 Section 2.3

Asset Condition

		# asset units				# asset units				# asset units				# asset units			
Asset Category		Population	2014 Condition			Population	2015 Condition			Population	2016 Condition			Population	2017 Condition		
			High Risk	Medium Risk	Low Risk		High Risk	Medium Risk	Low Risk		High Risk	Medium Risk	Low Risk		High Risk	Medium Risk	Low Risk
Station Transformers	All	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	In Service	1211	22%	21%	57%	1215	21%	15%	64%	1222	23%	17%	60%	1226	24%	17%	59%
	Spares	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mobile Unit Substations		30	17%	27%	60%	30	17%	30%	57%	30	43%	10%	50%	31	48%	6%	45%
Asset Category		Population	Condition			Population	Condition			Population	Condition			Population	Condition		
			Poor	Fair	Good		Poor	Fair	Good		Poor	Fair	Good		Poor	Fair	Good
Reclosers	All	2197	70%	6%	24%	2226	68%	6%	25%	2263	66%	5%	29%	2258	55%	8%	37%
	Oil	Note 1															
	Vaccum	Note 1															
	Metalclad	Note 1															
Circuit Breakers	All	**157**	**0%**	**1%**	**99%**	**155**	**0%**	**1%**	**99%**	**154**	**0%**	**0%**	**100%**	**152**	**0%**	**1%**	**99%**
	Oil	13	0%	0%	100%	13	0%	0%	100%	13	0%	0%	100%	13	0%	0%	100%
	Vaccum	4	0%	0%	100%	4	0%	0%	100%	4	0%	0%	100%	4	0%	0%	100%
	Metalclad	140	0%	1%	99%	138	0%	1%	99%	137	0%	0%	100%	135	0%	1%	99%
Switches		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuses		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Station Structures		Note 2												2167	2%	28%	70%
Fences		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Station Grounding Systems		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Station Service Transformers		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Insulators		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bus Work		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Protection Relays		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
IEDs		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Spill Containment Systems		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MUS Structures		Note 2												787	10%	29%	61%
Poles	All	**1,575,195**	**4%**	**13%**	**83%**	**1,582,962**	**4%**	**14%**	**82%**	**1,603,016**	**4%**	**13%**	**83%**	**1,604,073**	**4%**	**16%**	**79%**
	Wood	1,522,376	4%	14%	83%	1,532,162	4%	14%	82%	1,553,617	3%	13%	83%	1,555,520	4%	17%	79%
	Steel	6,238	0%	1%	99%	6,230	0%	1%	98%	6,220	0%	3%	97%	6,230	0%	3%	97%
	Concrete	2,449	0%	2%	98%	2,457	0%	3%	97%	2,424	1%	7%	93%	2,407	1%	7%	93%
	Composite	799	0%	2%	98%	1,435	0%	1%	99%	1,878	0%	2%	98%	2,464	0%	1%	99%
	Red Pine Wood	43,333	13%	5%	83%	40,678	16%	5%	79%	38,877	20%	6%	75%	37,451	23%	7%	71%
Rights of Way		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Line Transformers	All	NA	NA	NA	NA	499,490	NA	NA	NA	508,583	NA	NA	NA	514,527	NA	NA	NA
	Pole Mounted Transformers	NA	NA	NA	NA	445,297	NA	NA	NA	451,517	NA	NA	NA	455,438	NA	NA	NA
	Pad Mounted Transformers	NA	NA	NA	NA	54,193	NA	NA	NA	57,066	NA	NA	NA	59,089	NA	NA	NA
	Submersible transformers	NA	NA	NA	NA		NA	NA	NA		NA	NA	NA		NA	NA	NA
	Transclosures and Pole-Trans Transformer	NA	NA	NA	NA		NA	NA	NA		NA	NA	NA		NA	NA	NA
Submarine Cables		NA	NA	NA	NA	3,308	NA	NA	NA	3,747	NA	NA	NA	3,792	NA	NA	NA

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Association of Major Power Consumers in Ontario Interrogatory # 24

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 2.3 Page: - Asset Failures

Interrogatory:

a) Please complete the attached excel spreadsheet.

b) Please provide a live excel version of the completed spreadsheet.

c) Please confirm this asset failure data is the input to SAIFI.

Response:

a) & b) Please refer to Attachment 1 to this response. For the majority of asset subcomponents listed in Attachment 1, Hydro One does not report interruptions to the level of granularity required for asset subcomponents to be identified during an equipment failure.

c) Yes, this asset failure data is an input to SAIFI where the failure results in an outage. Note that in some cases, multiple assets can fail for a single outage or a failure of an asset may not directly result in an outage.

Witness: GARZOUZI Lyla

D24-AMPCO-24
Ref: B1-1-1 Section 2.3

Asset Failures

Asset Category		Population	#Failures 2011	#Failures 2012	#Failures 2013	#Failures 2014	#Failures 2015	#Failures 2016	#Failures 2017
Station Transformers	All	Note 1	19	12	16	7	8	12	19
	In Service		19	12	16	7	8	12	19
	Spares		NA	NA	NA	NA	NA	NA	NA
Mobile Unit Substations			0	0	0	1	0	0	0
Reclosers	All		Note 2						
	Oil								
	Vaccum								
	Metalclad								
Circuit Breakers	All								
	Oil								
	Vaccum								
	Metalclad								
Switches									
Fuses									
Station Structures									
Fences									
Station Grounding Systems									
Station Service Transformers									
Insulators									
Bus Work									
Protection Relays									
IEDs									
Spill Containment Systems									
MUS Structures									
Poles	All		2512	2087	3138	2051	2161	2475	2588
	Wood		Note 3						
	Steel								
	Concrete								
	Composite								
	Red Pine Wood								
Rights of Way			Note 4						
Line Transformers	All		Note 5						
	Pole Mounted Transformers								
	Pad Mounted Transformers								
	Submersible transformers								
	Transclosures and Pole-Trans Transformer								
Submarine Cables									
Conductor	All								
	Overhead								
	Underground								
Switches	Air Break & Load Break - 3 Phase								
Reclosers	All								
	Hydraulic								
	Electronic								
Regulators									
Capacitor Banks									
AMI	All		Note 6						
	Retails Meters								
	Collectors								
	Repeaters								

NA	Not applicable.
Note 1	Please refer to Exhibit I-23-AMPCO-23 and Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3 for the population information.
Note 2	Hydro One does not track failures at this level of granularity. However, Hydro One does track the total outage failures for distribution stations, please refer to interrogatory response Exhibit I-29-AMPCO-28 "Distribution Stations - # outages/year".
Note 3	Hydro One does not track failures at this level of granularity.
Note 4	Please refer to Exhibit I-29-AMPCO-28 for tree contacts that impact the distribution system along Hydro One's rights-of-way.
Note 5	Hydro One does not track failures at this level of granularity. However, Hydro One does track the total outage failures for the other line components, please refer to interrogatory response Exhibit I-29-AMPCO-28 "Other Line Components - # outages/year".
Note 6	The annual average failure rates for retail meters is 15,600, collectors is 700, and repeaters is 1,170.

UNDERTAKING – JT 3.1-6

Reference

I-24-AMPCO-20 (a)

Preamble: The response indicates that HONI does not track the age an asset fails for every asset category.

Undertaking

Please provide the asset groups where HONI has data on the age an asset fails.

Response

Hydro One tracks asset age of failures for station transformers and mobile unit substations asset groups.

Witness: JESUS Bruno

Association of Major Power Consumers in Ontario Interrogatory # 25

Issue:
Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:
B1-01-01 Section 2.3 Planned Replacements

Interrogatory:
a) Please complete the attached excel spreadsheet.

b) Please provide a live excel version of the completed spreadsheet.

Response:
a, b) Please refer to Attachment 1 to this response, for details on planned replacements.

D24-AMPCO-25
Ref: B1-1-1 Section 2.3

Asset Replacment - Planned

Asset Category		Population	# Replaced 2011	# Replaced 2012	# Replaced 2013	# Replaced 2014	# Replaced 2015	# Replaced 2016	# Replaced 2017	# Forecast to be Replaced 2018	# Forecast to be Replaced 2019	# Forecast to be Replaced 2020	# Forecast to be Replaced 2021	# Forecast to be Replaced 2022
			# Asset Units											
Station Transformers	All		9	36	44	42	65	22	15	12	26	24	29	25
	In Service		3	10	15	20	35	17	11	8	21	18	23	19
	Spares		6	26	29	22	30	5	4	4	5	6	6	6
Mobile Unit Substations (Note 6)			2	3	1	2	0	0	1	2	1	2	1	0
Reclosers (Note 7)	All		5	20	44	25	63	55	42	32	47	56	60	63
	Oil		Note 2											
	Vaccum													
	Metalclad		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Circuit Breakers	All		Note 3											
	Oil													
	Vaccum													
	Metalclad													
Switches (Note 7)			6	9	14	24	47	22	4	18	25	26	33	33
Fuses			Note 4											
Station Structures														
Fences														
Station Grounding Systems														
Station Service Transformers														
Insulators														
Bus Work														
Protection Relays														
IEDs														
Spill Containment Systems			3	0	2	1	1	1	0	1	1	1	1	1
MUS Structures (Note 8)			0	6	6	8	15	15	9	23	30	31	40	40
Poles	All	Note 1	7,282	7,452	10,720	11,179	11,837	12,355	9,642	9,600	14,300	16,000	16,123	16,128
	Wood		Note 2											
	Steel													
	Concrete													
	Composite													
	Red Pine Wood		374	1,180	2,139	2,652	2,655	1,801	1,426	Note 5				
Rights of Way	kilometers of line clearing completed		NA	11,195	10,378	9,474	10,366	11,753	14,382	34,666	34,666	34,666	34,666	34,666
Line Transformers	All		NA	83	41	18	69	379	0	2,182	2,182	2,182	3,258	3,258
	Pole Mounted Transformers		NA	0	0	0	34	347	0	2,152	2,152	2,152	3,228	3,228
	Pad Mounted Transformers		NA	33	28	0	0	0	0	0	0	0	0	0
	Submersible transformers		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Transclosures and Pole-Trans Transformer		NA	50	13	18	35	32	0	30	30	30	30	30
Submarine Cables (metres)			NA	62,158	62,155	49,515	56,416	103,693	73,285	65,000-75,000	65,000-75,000	65,000-75,000	65,000-75,000	65,000-75,000
Conductor	All		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Overhead (metres)		NA	27303	18496	7541	40900	28991	1800	NA	NA	NA	NA	NA
	Underground		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Switches	Air Break & Load Break - 3 Phase		NA	16	4	9	21	10	7	30	30	30	30	30
Reclosers/Regulators	All		NA	NA	NA	NA	NA	NA	NA	250	250	250	250	250
	Hydraulic		Note 2											
	Electronic													
Capacitor Banks			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AMI	All		65,600	53,100	94,750	74,150	55,300	58,900	56,700	48,500	45,200	44,900	48,400	252,600
	Retails Meters		57,000	49,000	92,000	72,000	50,000	55,000	55,000	46,600	43,300	43,000	46,500	250,700
	Collectors		1,600	1,100	750	150	4,000	3,000	700	700	700	700	700	700
	Repeaters		7,000	3,000	2,000	2,000	1,300	900	1,000	1,200	1,200	1,200	1,200	1,200

NA	Not applicable/Not available.
Note 1	Please refer to Exhibit I-23-AMPCO-23 and Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3 for the population information.
Note 2	Hydro One does not track plannned replacements to this level of granularity for subtype.
Note 3	When distribution station breakers are replaced, they are replaced with reclosers.
Note 4	Hydro One does not track planned replacements to this level of granularity; as these assets are generally addressed as part of the integrated distribution station refurbishments not as individual component replacements.
Note 5	Hydro One does not have a forecast for red pine poles specifically as they will be addressed based on condition and priority relative to other poles.
Note 6	Historically Hydro One replaced trailers and transformers seperately. Therefore the 2012 to 2017 data represents the number of MUSs that were repaired in total. Whereas the 2018 to 2022 forecast represent the number of full MUS replacements.
Note 7	These replacements include the total number replaced under both the component replacement program and station refurbishments.
Note 8	The forecast for MUS structure includes replacements under the component replacement program and station refurbishments. Whereas historical accomplishments only include planned component replacements.

OEB Staff Interrogatory # 66

Issue:

Issue 17: Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?

Reference:

B1-01-01 Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.1 (5.2.3 A and B) Methods and Measures, Table 8 – Distribution OEB Scorecard, Page 1918 of 2930.

Table 8 – Distribution OEB Scorecard

			Historical Results						Target	
RRF Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2018
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	72%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	86%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	81%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,640	8,733
		Vegetation Management - Gross Cyclical Cost per km $			New Program				9,441	9,382
		Station Refurbishments Gross Cost per MVA in $*	386,000		318,000	348,000	500,000	557,000	461,000	454,000
		OM&A dollars per customer	456	451	498	551	453	455	449	455
		OM&A dollars per km of line	4,723	4,676	5,109	5,654	4,719	4,773	4,700	4,758
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,200	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	6,900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	145	145
		SAIDI Rural duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.1	9.0
		SAIFI Rural frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.4	3.4
		SAIDI Urban duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.8	2.8
		SAIFI Urban frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.7	1.7
		Large Customer Interruption Frequency (LDA's) frequency of outages		New Measure	135	197	228	136	143	143

*There were no station refurbishment units matching the criteria completed in 2012

Interrogatory:

a) Please explain the sustained drop in 'Customer Satisfaction – Perception Survey %' for each year starting 2014 to 2016. Is it due to factors outside of the control of Hydro One, such as weather-related outages?

b) In 2013, pole replacement costs are at their lowest point, SAIFI, SAIDI and other outage measures are relatively good, while the customer satisfaction measure is higher than other years. Has Hydro One analyzed the correlations between the metrics listed in the scorecard? If yes, which metric correlates best with higher customer satisfaction measures?

Witness: PUGLIESE Ferio

c) What are the most significant asset failure modes captured in the "Number of Line Equipment Caused Interruptions" category? What are the typical triggering causes of these failures (e.g.: high winds, snow load, extreme heat, spontaneous failure, etc.)?

Response:

a) Based on Hydro One's satisfaction surveys and research, the following issues resulted in the decline in customer satisfaction between 2014 and 2016: billing accuracy, lack of trust, rates charged, and fairness of charges. The Electricity Price Index increased substantially since 2013, resulting in a decline in customer satisfaction.

b) Quality and reliability are considered when measuring customer satisfaction with Hydro One. As an example, the Hydro One's Customer Engagement analyzed the correlation between outages and reliability with customer satisfaction (as per Exhibit B1, Tab 1, Schedule 1, Attachment 1).

c) Pole, conductor, insulator, switch failures are the most significant asset failures in terms of their contribution to SAIFI and SAIDI. The Hydro One database classifies all customer interruptions resulting from equipment failures as "Defective Equipment", regardless of the specific triggering causes of the failures. Therefore, the data set does not have the level of granularity to report the typical triggering causes of failure for the "Line Equipment Caused Interruptions".

School Energy Coalition Interrogatory # 37

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 1.4, Table 8-15

Interrogatory:

Please provide revised versions of Tables 8 through 15 that include 2017 actual reliability information.

Response:

Provided below are revised versions of Tables 9 through 15 that include 2017 actual reliability information.

For Table 8, please refer to Exhibit I-18-SEC-029, Dx OEB Scorecard; updated Cost Control measures are not available for 2017 as audited 2017 actuals are not available.

Table 9 – Outcome Measures from EB-2013-0416

Year	Actual			
	2014	2015	2016	2017
Vegetation Caused Interruptions*	6,540	6,944	7,439	7,800
Substation Caused Interruptions	158	141	103	123
Distribution Line Equipment Caused Interruptions*	8,311	8,164	7,674	8,786
Number of Replaced Poles	11,179	11,837	12,355	9,642
Number of Pole Top Transformers with PCB Oil	N/A	34	347	0
Residential and Small Business Satisfaction (%)	67	70	66	71
Handling of Unplanned Outages Satisfaction (%)	75	76	83	76
Estimated Bills Issued as % of Total Issued**	N/A	4	N/A	N/A

***Table 9 is corrected for a typographical error in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4, s.1.4.2 Outcome Measures: EB-2013-0416, Table 9, Actual 2016 values.**

****No longer measured, replaced by Billing Accuracy measure, refer to Exhibit I-18-SEC-29, Electricity Distributor Scorecard.**

Table 10 - Historical SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	11.3	27.4	9.9	12.9	13.2	13.0
Including LOS and Excluding FM	7.5	7.3	7.9	8.3	8.3	8.5
Excluding LOS and Including FM	10.6	26.6	9.4	12.2	12.6	12.2
Excluding LOS and Excluding FM	7.0	6.9	7.4	7.6	7.8	7.9

Table 11 - Historical SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	3.7	4.6	3.6	3.6	3.4	3.5
Including LOS and Excluding FM	3.1	2.8	3.3	3.1	2.8	2.8
Excluding LOS and Including FM	3.2	4.2	3.0	3.1	2.9	2.9
Excluding LOS and Excluding FM	2.6	2.5	2.7	2.6	2.5	2.3

Table 12 - Historical CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	3.1	6.0	2.8	3.6	3.9	3.7
Including LOS and Excluding FM	2.4	2.6	2.4	2.7	3.0	3.0
Excluding LOS and Including FM	3.3	6.3	3.1	3.9	4.3	4.2
Excluding LOS and Excluding FM	2.7	2.8	2.7	2.9	3.1	3.4

Table 13 - SAIDI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	0.03	0.01	0.00	0.02	0.03	0.05
Defective Equipment	2.57	6.59	3.03	3.55	3.00	3.62
Foreign Interference	0.44	0.46	0.44	0.40	0.41	0.57
Human Element	0.04	0.11	0.08	0.08	0.05	0.07
Loss of Supply	0.72	0.96	0.56	0.72	0.61	0.86
Scheduled	1.41	1.53	1.48	1.43	1.48	0.89
Tree Contacts	4.24	14.67	3.36	5.53	6.17	6.22
Unknown/Other	1.84	3.09	0.96	1.20	1.43	0.77

Table 14 - SAIFI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	0.00	0.01	0.00	0.00	0.00	0.01
Defective Equipment	0.73	1.07	0.83	0.88	0.75	0.96
Foreign Interference	0.15	0.15	0.16	0.15	0.17	0.19
Human Element	0.03	0.06	0.08	0.07	0.04	0.05
Loss of Supply	0.54	0.40	0.62	0.50	0.49	0.57
Scheduled	0.62	0.68	0.63	0.60	0.57	0.41
Tree Contacts	0.80	1.36	0.62	0.78	0.81	0.88
Unknown/Other	0.81	0.90	0.61	0.60	0.57	0.41

Table 15 - CAIDI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	8.46	2.43	4.32	4.12	6.40	3.53
Defective Equipment	3.50	6.17	3.65	4.06	3.99	3.76
Foreign Interference	2.87	3.07	2.77	2.77	2.36	2.94
Human Element	1.47	1.67	0.96	1.20	1.36	1.42
Loss of Supply	1.34	2.41	0.90	1.43	1.25	1.51
Scheduled	2.26	2.25	2.35	2.38	2.60	2.18
Tree Contacts	5.31	10.79	5.42	7.12	7.66	7.07
Unknown/Other	2.29	3.43	1.59	1.98	2.49	1.87

Witness: JESUS Bruno

Association of Major Power Consumers in Ontario Interrogatory # 13

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 1.4

Interrogatory:

a) Page 13 Table 9: Please provide the forecast for the years 2014 to 2016 for each outcome measure in Table 9 that is still measured compared to actuals.

b) Page 14: Please provide the total number of outages for the years 2011 to 2017.

c) Page 14: Please provide the total number of outages in part (b) that resulted in a customer interruption for each of the years 2011 to 2017.

d) If there is a difference between a failure, outage and interruption, please explain the difference.

e) Page 15: Please provide Hydro One's MAIFI and MAIDI results by year for the years 2012 to 2017.

f) Page 21 Table 10: Please provide a version of Table 10 that includes 2017 and Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

g) Page 22 Table 11: Please provide a version of Table 11 that includes 2017 and Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

h) Page 23 Table 12: Please provide a version of Table 12 that includes 2017 and Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

i) Tables 13, 14 and 15: The Tables include eight Cause Codes. There are 10 Cause Codes. Please identify the two missing Cause Codes and explain where the data for these two Cause Codes is captured.

j) Tables 13, 14 and 15 include outages due to Force Majeure. Please provide the tables excluding Force Majeure.

k) Page 24 Table 13: Please provide the contribution to SAIDI by Cause Code based on number of customer interruption hours excluding Force Majeure and add 2017 data to the Table.

l) Page 25 Table 14: Please provide the contribution to SAIFI by Cause Code based on number of customer interruptions excluding Force Majeure and add 2017 data to the Table.

m) Page 27 Table 15: Please provide Table 15 based on the changes to Table 13 and 14 in parts (k) and (l).

n) Please provide the number of customer interruptions and customer interruption hours contributed by Force Majeure compared to the total number of customer interruptions and customer interruption minutes for each of the years 2011 to 2017.

o) Please provide a chart that sets out the equipment causes of Defective Equipment and the contribution to SAIDI and SAIFI for each equipment type in terms of number of customer interruption hours and number of customer interruptions for each of the years 2011 to 2017.

p) Page 24 Table 13: Please explain the types of interruptions included in Unknown/Other.

q) Page 24 Table 13: Please explain the increases in Defective Equipment, Tree Contacts and Unknown/Other outages in 2013.

r) Please explain where data due to Force Majeure outages are captured in the Table 13.

s) Please explain how the classification of outages due to Adverse Environment, Defective Equipment and Tree Contacts are differentiated for staff.

Response:

a) For 2014 to 2016 targets for Table 9, please refer to Exhibit I-18-SEC-031.

b) Hydro One's distribution reliability only measures and tracks outages that cause sustained customer interruptions which is identical to the table presented in Response, c) below.

Witness: JESUS Bruno

c) Following are the total number of outages that caused sustained customer interruptions from 2011 to 2017:

Year	2011	2012	2013	2014	2015	2016	2017
Number of Interruptions	40,927	35,013	44,834	33,200	35,074	35,762	35,720

d) Asset failure could cause outages to Hydro One's assets, but may not necessarily cause outages or interruptions to Hydro One's customers. The outages include momentary outages and sustained outages. Hydro One tracks sustained outages that caused customer interruptions.

e) Hydro One does not track MAIFI and MAIDI.

f) Provided below is a revised version of Table 10, that includes 2017 data as well as Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

Table 10 - Historical SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	11.3	27.4	9.9	12.9	13.2	13.0
Including LOS and Excluding FM	7.5	7.3	7.9	8.3	8.3	8.5
Excluding LOS and Including FM	10.6	26.6	9.4	12.2	12.6	12.2
Excluding LOS and Excluding FM	7.0	6.9	7.4	7.6	7.8	7.9
Excluding LOS and Excluding FM Excluding Scheduled Outages	5.6	5.4	6.0	6.2	6.4	7.1

g) Provided below is a revised version of Table 11, that includes 2017 data as well as Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

Table 11 - Historical SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	3.7	4.6	3.6	3.6	3.4	3.5
Including LOS and Excluding FM	3.1	2.8	3.3	3.1	2.8	2.8
Excluding LOS and Including FM	3.2	4.2	3.0	3.1	2.9	2.9
Excluding LOS and Excluding FM	2.6	2.5	2.7	2.6	2.5	2.3
Excluding LOS and Excluding FM Excluding Scheduled Outages	2.0	1.9	2.0	2.0	1.9	1.9

h) Provided below is a revised version of Table 12, that includes 2017 data as well as Outage Cause "Excluding LOS and Excluding FM and Excluding Scheduled Outages".

Table 12 - Historical CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Including LOS and Including FM	3.1	6.0	2.8	3.6	3.9	3.7
Including LOS and Excluding FM	2.4	2.6	2.4	2.7	3.0	3.0
Excluding LOS and Including FM	3.3	6.3	3.1	3.9	4.3	4.2
Excluding LOS and Excluding FM	2.7	2.8	2.7	2.9	3.1	3.4
Excluding LOS and Excluding FM Excluding Scheduled Outages	2.8	2.9	2.9	3.0	3.3	3.7

i) Adverse Weather and Lightning are not used as a Cause Code. A large portion of Adverse Weather related outages are captured in Tree Contacts. A large portion of Lightning outages are captured under Tree Contacts and Defective Equipment.

j) Provided below are Tables 13, 14, and 15 excluding Force Majeure.

Table 13 - SAIDI by Outage Cause, Excluding FM

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.03	0.01	0.00	0.02	0.03
Defective Equipment	1.80	1.87	2.56	2.58	1.92
Foreign Interference	0.43	0.39	0.44	0.39	0.39
Human Element	0.04	0.10	0.07	0.07	0.05
Loss of Supply	0.49	0.50	0.46	0.62	0.43
Scheduled	1.37	1.39	1.47	1.41	1.46
Tree Contacts	2.16	1.94	2.03	2.26	2.98
Unknown/Other	1.14	1.08	0.86	0.92	1.01

Table 14 - SAIFI by Outage Cause, Excluding FM

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.00	0.01	0.00	0.00	0.00
Defective Equipment	0.59	0.62	0.74	0.77	0.61
Foreign Interference	0.15	0.13	0.16	0.14	0.16
Human Element	0.03	0.05	0.08	0.06	0.03
Loss of Supply	0.48	0.30	0.59	0.48	0.45
Scheduled	0.61	0.62	0.63	0.59	0.56
Tree Contacts	0.55	0.44	0.48	0.50	0.60
Unknown/Other	0.68	0.61	0.58	0.56	0.51

Table 15 - CAIDI by Outage Cause, Excluding FM

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	8.48	2.35	4.32	4.12	6.62
Defective Equipment	3.03	3.03	3.44	3.35	3.16
Foreign Interference	2.88	2.99	2.77	2.73	2.36
Human Element	1.47	1.79	0.95	1.11	1.55
Loss of Supply	1.02	1.68	0.79	1.29	0.96
Scheduled	2.26	2.24	2.35	2.41	2.61
Tree Contacts	3.97	4.37	4.19	4.48	4.98
Unknown/Other	1.68	1.77	1.48	1.64	1.99

k) Provided below is a revised version of Table 13, that shows contribution to SAIDI by Cause Code based on number of customer interruption hours excluding Force Majeure for 2012-2017.

Table 13 – Contribution to SAIDI by Cause Code, Excluding FM

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	41906.22	16334.05	5031.641	22368.59	39617.87	71385.08
Defective Equipment	2227065	2363865	3302190	3372307	2571355	3197914
Foreign Interference	535916.2	489152.7	565647.4	505268.1	522624.4	772909.1
Human Element	51952.16	123606.1	95543.02	93126.65	69236.32	87984.28
Loss of Supply	605820.7	631173.6	595004.6	811218.2	581757.1	828033.8
Scheduled	1691844	1764901	1900398	1842877	1956799	1165780
Tree Contacts	2674530	2451106	2620388	2946799	3994257	4904331
Unknown/Other	1404273	1364067	1111613	1198217	1353379	767155.5

l) Provided below is a revised version of Table 14, that shows contribution to to SAIFI by Cause Code based on number of customer interruptions excluding Force Majeure for 2012-2017.

Table 14 – Contribution to SAIFI by Cause Code, Excluding FM

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	4942	6956	1166	5423	5983	20148
Defective Equipment	734910	779870	958997	1006506	813973	1016802
Foreign Interference	185876	163854	203997	185158	221131	262841
Human Element	35455	69103	100834	83953	44783	63147
Loss of Supply	594764	375911	757273	626832	608748	687739
Scheduled	748802	789023	808684	765013	750779	520296
Tree Contacts	673710	560758	625400	658345	801473	813341
Unknown/Other	836810	768884	750548	732415	679805	504046

m) Provided below is a revised version of Table 15, based on the changes to Table 13 and 14 in parts (k) and (l).

Witness: JESUS Bruno

Table 15 – Contribution to CAIDI by Cause Code, Excluding FM

Outage Cause	2012	2013	2014	2015	2016	2017
Adverse Environment	8.48	2.35	4.32	4.12	6.62	3.54
Defective Equipment	3.03	3.03	3.44	3.35	3.16	3.15
Foreign Interference	2.88	2.99	2.77	2.73	2.36	2.94
Human Element	1.47	1.79	0.95	1.11	1.55	1.39
Loss of Supply	1.02	1.68	0.79	1.29	0.96	1.20
Scheduled	2.26	2.24	2.35	2.41	2.61	2.24
Tree Contacts	3.97	4.37	4.19	4.48	4.98	6.03
Unknown/Other	1.68	1.77	1.48	1.64	1.99	1.52

n) Provided below are charts showing the number of customer interruptions and customer interruption hours contributed by Force Majeure compared to the total number of customer interruptions and customer interruption hours for each of the years 2012 to 2017.

Customer Interruption Hours

	2012	2013	2014	2015	2016	2017
FM	4725738	25521221	2615083	6096472	6599497	6193871
Total	13959045	34725426	12810900	16888653	17688523	17989364

Customer Interruption

	2012	2013	2014	2015	2016	2017
FM	737659	2345300	374389	605315	649450	915811
Total	4552928	5859659	4581288	4668960	4576125	4804171

o) Hydro one does not report customer Interruptions to the level of granularity required for equipment subcomponent failures. Only system level numbers can accurately be provided.

p) Unknown/Other interruptions are interruptions classified with no known apparent cause or reason that can be attributed to the root cause of the outage.

q) The increases in Defective Equipment, Tree Contacts and Unknown/Other outages in 2013 was largely due to the large impact from the December 2013 Ice Storm, described in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4.2.1 Reliability Results, p.18.

r) Data due to Force Majeure outages is captured throughout all the Outage Causes.

Witness: JESUS Bruno

s) The following are classifications of outages/interruptions:

  a. Adverse Environment: Customer outages/interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.
  b. Defective Equipment: Customer outages/interruptions resulting from equipment failures.
  c. Tree Contacts: Customer outages/interruptions caused by faults due to trees or tree limbs contacting energized circuits.

Witness: JESUS Bruno

the MicroFit projects. With this explanation, AESI is satisfied that Hydro One has met IESO's requirements.

AESI did recognize a few specific areas within the DSP that did not follow the prescribed Chapter 5 outline. For example, Section 1.3, Customer Engagement. AESI found its positioning appropriate considering the importance of its customer engagement within its business objectives and planning process. AESI also considered the placement of Sections 1.5 Productivity and Continuous Improvement and Section 1.6 Benchmarking appropriate as this highlights the importance of these topics with Hydro One's increased commercial focus.

Hydro One also made the decision to discuss "How the Plan reflects Regional Planning, Customer Needs and Benchmarking" in its first chapter, with a summary in the later section as prescribed in Chapter 5. This reflects Hydro One's desire to illustrate the complete picture of those activities in one section. AESI is in agreement with this approach.

AESI did identify areas of opportunity to better demonstrate alignment with the OEB requirements.

- In the section 1.4.2 (5.2.3b) - Performance Trends (Table 13 – SAIDI by Outage Cause) Hydro One only reported on 8 causes rather than the 10 prescribed by the OEB. Hydro One explained to AESI that this is due to software application limitations. Hydro One recognizes this difference in reporting and is working on correcting its outage cause data.
- AESI had several questions about Hydro One's use of the term "cost savings". Hydro One explained its interpretation of cost saving; the change in nature of costs within a specific timeframe - the "input/output" cost savings. Hydro One explained that; the "input/output" types of savings are included in the Productivity section. Other references to "cost savings" may include avoided costs, efficiency costs, or process innovation costs which may not directly affect productivity.
- AESI provided Hydro One with suggestions regarding other reporting metrics such as; job estimate to actual. Hydro One acknowledged that this was a meaningful metric and stated that it would be considered in the future.
- AESI suggested that in addition to the raw numbers for SAIDI, SAIFI and CAIDI that Hydro One also compute each to the attributable cause codes. Hydro One appreciated the suggestion and subsequently included that information in the DSP.

AESI provided Hydro One with numerous other points of clarification and suggestions. Hydro One stated that it appreciated AESI's points and suggestions. Hydro One provided AESI with

Association of Major Power Consumers in Ontario Interrogatory # 16

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-02 Page: 4 – AESI Final Report – Distribution system Plan Review

Interrogatory:

a) The Final Report is dated March 14, 2017. When was AESI retained and when did they conduct their review?

b) Page 4: AESI indicates Hydro One was unable to report reliability data on two cause codes due to software limitations. Please explain the software limitations.

c) Page 4: AESI provided Hydro One with suggestions regarding other reporting metrics such as job estimate to actual. Hydro One acknowledged that this was a meaningful metric and stated that it would be considered in the future. Please discuss the data availability for this metric and if it has incorporated this metric.

Response:

a) Hydro One contracted AESI on May 27, 2016 following the procurement process described in Exhibit I-24-SEC-046. AESI's review of the material was conducted in stages over the course of Q4 2016 and Q1 2017.

b) Hydro One currently reports against eight cause codes instead of ten as explained in part (i) of Exhibit I-24-APMCO-13. (Adverse Weather and Lightning are not used.) This fact was highlighted by AESI during their review, and reasons were provided as to why these cost codes were omitted. As discussed with AESI, software is a factor insofar as it can only determine a cause based on the sensory data automatically provided by the system. However, Hydro One is satisfied that the current methodology provides meaningful insight to support the investment planning process and plans to continue with the process in place rather than spending significant funds on software upgrades.

Witness: D'ANDREA Frank

c) AESI's suggestion stemmed from Section 5.2.3 a) of the OEB filing requirements which lists some examples of what types of activities a distributor could be measuring. AESI asked about a measure comparing job estimate to actual cost. As stated, Hydro One appreciated the suggestion and plans to consider including such a measure in the future. The AESI suggestion came in mid-January of 2017 when Hydro One planned to file the Application in less than a three-month timeframe. As such, Hydro One did not include the measure in the filing.

UNDERTAKING – JT 3.1-4

Reference

I-24-AMPCO-13 (i)

Preamble: HONI does not use Adverse Weather and Lightning as Cause Codes.

Undertaking

i. Please provide the rationale for not using Adverse Weather and Lightning as Cause Codes.

ii. Does HONI have the data related to the contribution of Adverse Weather and Lightning to SAIDI and SAIFI? If yes, please provide.

iii. If data is not available, does HONI have a sense if the contribution of adverse weather and lightning to SAIDI and SAIFI is material in its service territory.

Response

i. Hydro One does not use Adverse Weather and Lightning as Cause Codes because we incorporate those causes into our existing Cause Codes. For example, Tree Contacts and Defective Equipment would capture Adverse Weather or Lightning causes. We do this to provide more meaningful insight in supporting our investment planning process.

ii. No

iii. Please see i.

Witness: JESUS Bruno

2.2.1 (5.3.2 A) DESCRIPTION OF THE DISTRIBUTION SERVICE AREA

The Hydro One distribution service area is over 99% rural with less than 1% considered to be in urban areas. Hydro One's distribution system includes approximately 1.6 million poles to serve 1.3 million customers. To service these rural areas the distribution system is radial in design, with very little transfer capability in supply to customers. A small part of the distribution system is monitored. M Class Sub Transmission feeders are monitored for volt, current, and status at the station. Smart grid devices have been deployed at the Owen Sound operating centre, including monitoring of line reclosers, capacitors and distribution stations in the operating centre's area. Otherwise, Hydro One has limited monitoring and control of breakers and switches on the system. Furthermore, the majority of the Hydro One distribution system is located overhead, with only about 8% of the system being underground. This design is consistent with other rural systems.

The map below is a representation of Hydro One's distribution service territory.

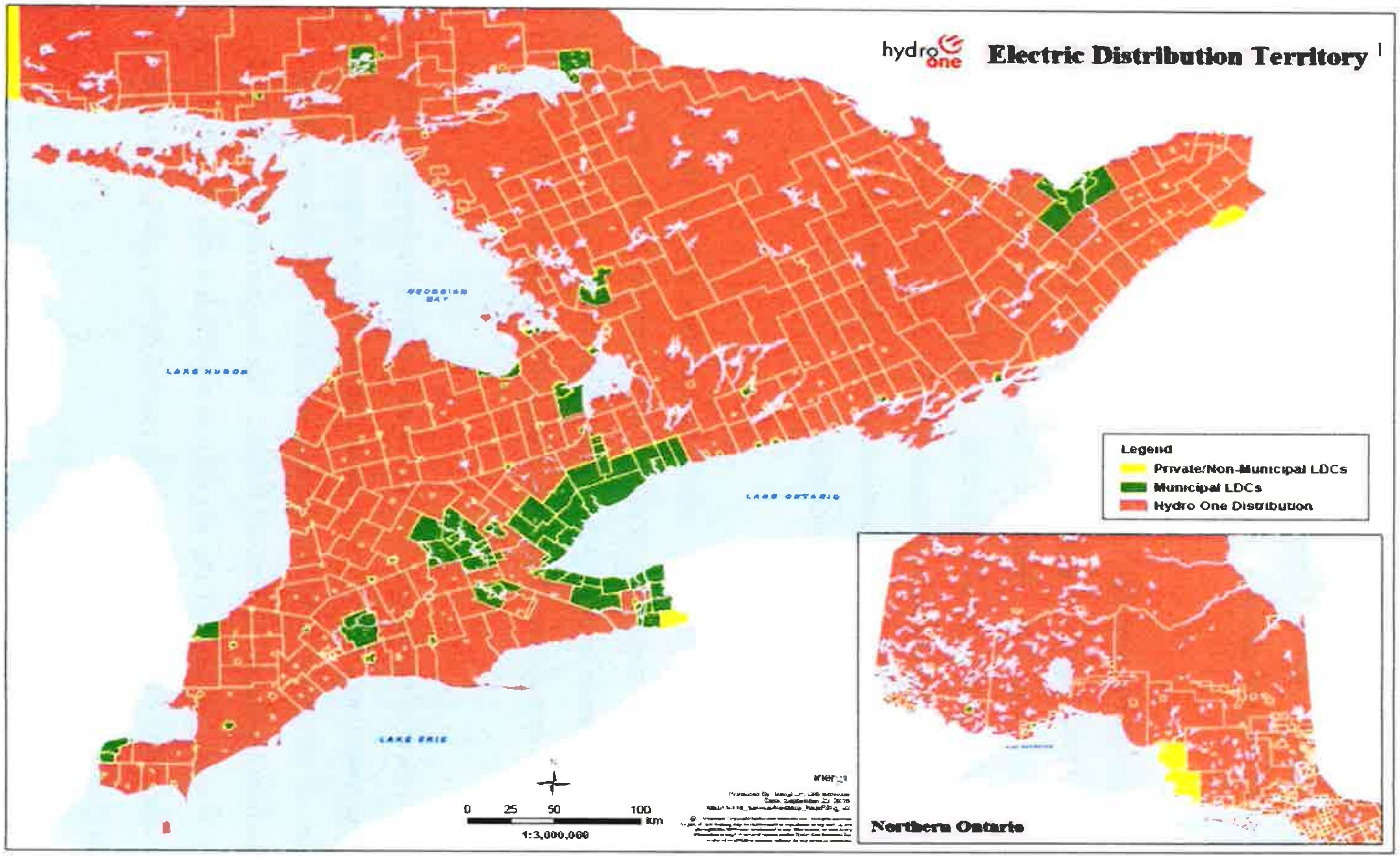

Figure 12 - Hydro One's Distribution Territory

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Witness: Lyla Garzouzi

Hydro One's service to its customer is susceptible to a variety of weather conditions. Storms in Ontario include such extremes as blizzards, hail, ice storms, lightning and thunderstorms including tornadoes. Due to the radial configuration in most of the service territory, storm damage almost always results in an outage to customers and requires immediate repair to restore service.

To effectively manage the response to trouble calls from customers, the initial problem assessment and dispatching of a response is handled through a single facility, the Ontario Grid Control Centre ("OGCC"). Hydro One has Service Centres located throughout the province to cost-effectively provide operating, maintenance and restoration services. These Service Centres provide base locations for field crews and related materials, tools and equipment. In storm conditions, additional crews can be brought in from unaffected Service Centres to assist with power restoration.

Hydro One deems a force majeure to have occurred when 10% or more of Hydro One customers have been interrupted by an event. Over the past 3 years, there has been an average of 8 force majeure days per year. These types of events may include severe ice storms in the winter, or major wind and rain events in the summer months.

Another characteristic of Hydro One's service area is Ontario's forests. Southern Ontario is mostly agricultural land, but has some scattered deciduous forests. The eastern and central regions of the Hydro One service area are about fifty percent densely forested with large conifer, deciduous, and mixed forests. The northern zone, is about 74 percent covered with forests. Given that the majority of the Hydro One distribution system is located overhead, with only about 8% of the system being underground, the system is susceptible to vegetation caused outages.

Witness: Lyla Garzouzi

As a result of this approach, the investment planning process that culminated in this Distribution Business Plan and the Distribution System Plan described herein was iterative; Hydro One created several different asset investment plans with different customer outcomes and rate impacts, and these plans were evaluated by the Executive Leadership Team and discussed with the company's Board of Directors. The Distribution Business Plan and the associated Distribution System Plan in this document represent an investment plan that appropriately aligns the needs and preferences of customers, customer rates and effective stewardship of the distribution system by Hydro One.

Circumstances & Challenges

Hydro One is the largest electricity distributor in Ontario. Hydro One serves more than 1.3 million customers in largely rural and suburban areas across Ontario, with approximately 123,000 circuit kilometers of lower-voltage power lines, 1.6 million poles and over 1,000 distribution and voltage regulating stations.

Geography

Hydro One's service area is one of the largest in North America. It is predominantly rural, with below average customer density by land area, higher than average tree density, and a higher than average number of storms, especially in winter, that damage the distribution system on a regular basis. Hydro One maintains over 100,000 kilometers of rights-of-way, and although the majority of the company's distribution power lines are along roadways, one-third of the lines are off-road, requiring the use of special equipment for access and maintenance.

Reliability

Reliability performance is affected by factors such as: vegetation, equipment performance, geography, and exposure to adverse weather, and as a result, the reliability of Hydro One's distribution system varies by location. In addition, much of Hydro One's distribution network uses a radial circuit design to cover large areas. A radial circuit design does not provide the redundant power supplies that are common in urban areas. These factors increase both the frequency and duration of power outages and also increase the time and cost of restoring power when outages occur.

Aging and Deteriorating Infrastructure

Much of Hydro One's distribution system was built in the 1950s and 1960s and as a result, many of the company's assets are approaching or beyond the end of their expected service life. While replacement decisions are based on actual asset condition, age is an indicator of additional asset replacements over the business planning period. For example, Hydro One currently has 240,000 wood poles (15% of fleet) that are beyond their expected service life of 60 years and 144 station transformers (12% of fleet) are beyond their expected life of 50 years. If no replacements are made in the next five years, the number of wood poles beyond their expected service life rises to 400,000 (25% of fleet) and the number of transformers beyond their

Ontario Energy Board
Commission de l'Énergie de l'Ontario

2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

May 11, 2005

index. It is defined as the average duration of interruptions in the year, and it is expressed as follows:

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ Customer\ Hours\ of\ Interruption}{Total\ Customer\ Interruptions}$$

A distributor is required to monitor this index monthly and to report to the Board on an annual basis.

Table 15.2
Cause of Service Interruption

Code	Cause
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	**Loss of Supply** Customer interruptions due to problems in the bulk electricity supply system
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	**Adverse Environment** Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing (previously Code 9)
8	**Human Element** Customer interruptions due to the interface of distributor staff with the system (previously Code 7)
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects (previously Code 8)

A distributor that has at least 3 years of data on this index should, at minimum, remain within the range of their historical performance.

The monthly information is to be reported as follows:

(1) total customer hours of interruptions (SAIDI)

(2) total number of customer interruptions (SAIFI)

(3) CAIDI [(1)/(2)]

15.3 Cause of Service Interruption

Monitoring the cause(s) of outages, in addition to monitoring the system reliability indices, provides valuable information as to the remedial work required. A distributor should therefore maintain a record of the causes of the outages, at a minimum, in accordance with the list presented in Table 15.2.

While annual reporting of this information to the Board is not mandatory, the Board will expect the distributor to produce this information should a review of its service reliability be necessary.

The following cause codes have been updated to correspond with the Canadian Electrical Association's guidelines.

Ontario Energy
Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie
de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

ELECTRICITY REPORTING & RECORD KEEPING REQUIREMENTS
Version dated March 15, 2018

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Cause of Interruption; and

d) Number of customer-hours of interruptions that occurred as a result of the cause of interruption.

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	**Loss of Supply** Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits.
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system.
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.
10	**Major Event** Customer interruptions due to a Major Event. These interruptions should also be counted under the actual Cause of Interruption listed above.

2016 YEARBOOK OF ELECTRICITY DISTRIBUTORS

PUBLISHED ON AUGUST 17, 2017

ONTARIO ENERGY BOARD | COMMISSION DE L'ÉNERGIE DE L'ONTARIO

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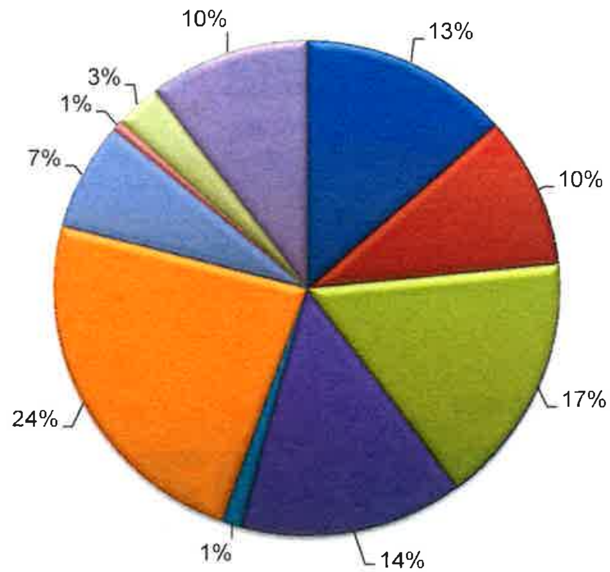
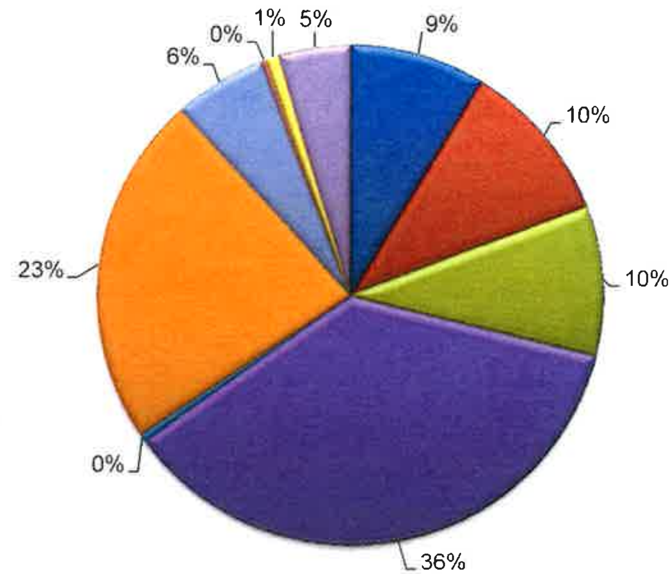
Frequency by Cause of Interruptions



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,402,852	89,548
1 - Scheduled Outage	1,036,281	15,379
2 - Loss of Supply	1,720,125	152,695
3 - Tree Contacts	1,495,227	305,321
4 - Lightning	125,282	12,368
5 - Defective Equipment	2,466,602	230,135
6 - Adverse Weather	746,682	399,331
7 - Adverse Environment	71,456	14,748
8 - Human Element	304,862	8,362
9 - Foreign Interference	1,072,311	40,969
Total	**10,441,680**	**1,268,856**

Duration by Cause of Interruptions



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	2,087,322	561,682
1 - Scheduled Outage	2,570,620	34,585
2 - Loss of Supply	2,371,550	680,380
3 - Tree Contacts	8,803,985	4,339,391
4 - Lightning	107,351	14,962
5 - Defective Equipment	5,574,904	1,523,780
6 - Adverse Weather	1,428,778	1,098,076
7 - Adverse Environment	92,299	8,082
8 - Human Element	190,314	3,017
9 - Foreign Interference	1,123,687	61,393
Total	**24,350,809**	**8,325,348**

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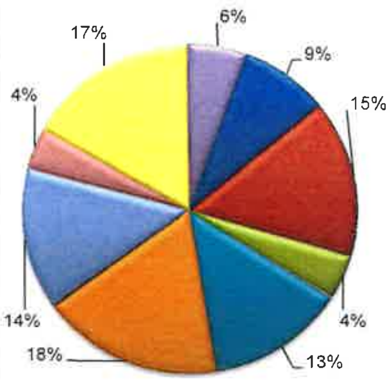
System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

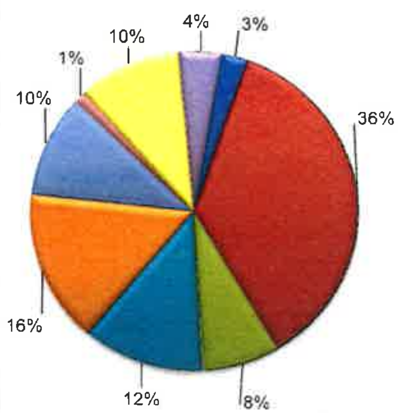
Greater Sudbury Hydro Inc.

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	3,685	-
1 - Scheduled Outage	6,701	-
2 - Loss of Supply	1,881	-
3 - Tree Contacts	85	-
4 - Lightning	5,771	-
5 - Defective Equipment	7,649	-
6 - Adverse Weather	6,154	-
7 - Adverse Environment	1,776	-
8 - Human Element	7,206	-
9 - Foreign Interference	2,487	-
Total	**43,395**	-

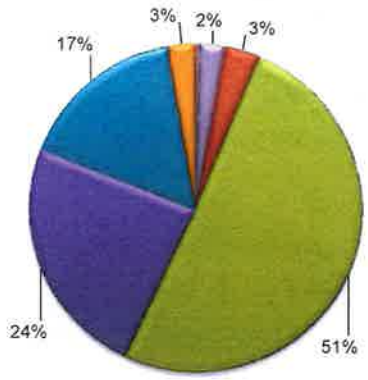
Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	1,567	-
1 - Scheduled Outage	22,221	-
2 - Loss of Supply	4,683	-
3 - Tree Contacts	114	-
4 - Lightning	7,346	-
5 - Defective Equipment	9,587	-
6 - Adverse Weather	6,453	-
7 - Adverse Environment	763	-
8 - Human Element	6,241	-
9 - Foreign Interference	2,606	-
Total	**61,582**	-

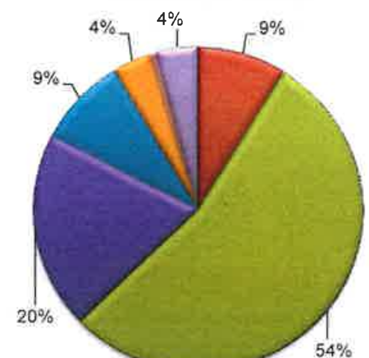
Grimsby Power Incorporated

Frequency by Cause



Number of Customer Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	15	-
1 - Scheduled Outage	531	-
2 - Loss of Supply	8,010	-
3 - Tree Contacts	3,785	-
4 - Lightning	2,587	-
5 - Defective Equipment	407	-
6 - Adverse Weather	15	-
7 - Adverse Environment	55	-
8 - Human Element	14	-
9 - Foreign Interference	371	-
Total	**15,790**	-

Duration by Cause



Number Customer-hours Interruptions		
Cause of Interruption	**Total Outages**	**Major Events**
0 - Unknown/Other	10	-
1 - Scheduled Outage	1,148	-
2 - Loss of Supply	7,197	-
3 - Tree Contacts	2,655	-
4 - Lightning	1,184	-
5 - Defective Equipment	492	-
6 - Adverse Weather	17	-
7 - Adverse Environment	66	-
8 - Human Element	1	-
9 - Foreign Interference	548	-
Total	**13,319**	-

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

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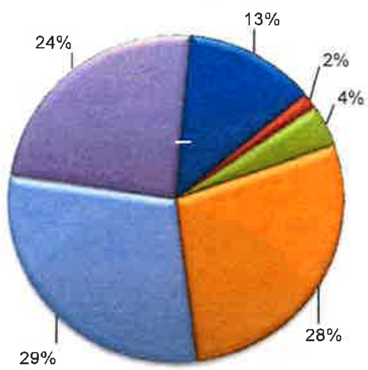
System Reliability by Cause of Interruptions for Loss of Electricity Power (see Glossary for Cause of Interruption Codes definitions)
For year ended
December 31

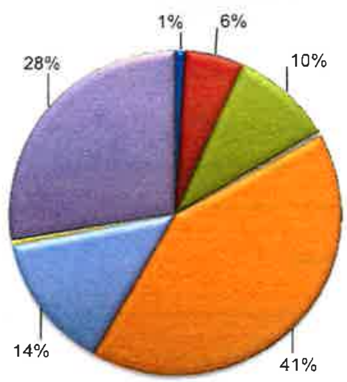
Hydro One Brampton Networks Inc.

Frequency by Cause



Cause of Interruption	Number of Customer Interruptions: Total Outages	Major Events
0 - Unknown/Other	14,145	-
1 - Scheduled Outage	1,758	-
2 - Loss of Supply	4,680	-
3 - Tree Contacts	66	-
4 - Lightning	27	-
5 - Defective Equipment	31,924	-
6 - Adverse Weather	33,015	-
7 - Adverse Environment	72	-
8 - Human Element	110	-
9 - Foreign Interference	27,195	-
Total	**112,992**	-

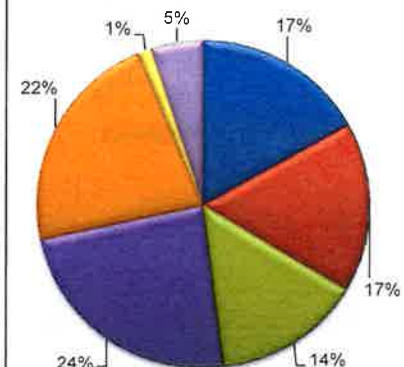
Duration by Cause



Cause of Interruption	Number Customer-hours Interruptions: Total Outages	Major Events
0 - Unknown/Other	722	-
1 - Scheduled Outage	4,012	-
2 - Loss of Supply	6,946	-
3 - Tree Contacts	138	-
4 - Lightning	137	-
5 - Defective Equipment	28,966	-
6 - Adverse Weather	9,643	-
7 - Adverse Environment	115	-
8 - Human Element	234	-
9 - Foreign Interference	19,448	-
Total	**70,362**	-

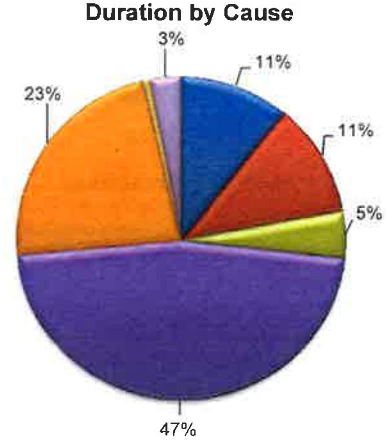
Hydro One Networks Inc.

Frequency by Cause



Cause of Interruption	Number of Customer Interruptions: Total Outages	Major Events
0 - Unknown/Other	769,293	89,488
1 - Scheduled Outage	766,013	15,234
2 - Loss of Supply	659,869	51,121
3 - Tree Contacts	1,080,478	279,005
4 - Lightning	-	-
5 - Defective Equipment	1,007,074	193,101
6 - Adverse Weather	-	-
7 - Adverse Environment	6,629	646
8 - Human Element	53,145	8,362
9 - Foreign Interference	233,624	12,493
Total	**4,576,125**	**649,450**

Duration by Cause



Cause of Interruption	Number Customer-hours Interruptions: Total Outages	Major Events
0 - Unknown/Other	1,914,729	561,349
1 - Scheduled Outage	1,991,203	34,405
2 - Loss of Supply	822,705	240,947
3 - Tree Contacts	8,271,595	4,277,338
4 - Lightning	-	-
5 - Defective Equipment	4,021,763	1,450,408
6 - Adverse Weather	-	-
7 - Adverse Environment	42,442	2,824
8 - Human Element	72,253	3,017
9 - Foreign Interference	551,833	29,208
Total	**17,688,523**	**6,599,497**

The information under Major Events includes the different causes of outages that happened during a Major Event (including low impact causes). Each outage and its cause may not individually constitute a Major Event but when considered in total, the cumulative outages reached the threshold of a Major Event.

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The main components maintained in the Distribution Lines Management program include:

- Poles;
- Rights of Way;
- Line Transformers;
- Submarine Cables; and
- Other Distribution Line Components.

2.3.2.1 POLES

Poles comprise the single largest component of Hydro One's lines asset base. Poles keep conductor and line equipment at a safe distance from the ground and other objects. Hydro One utilizes poles made from wood, concrete, steel and composite material based on specific situations. However, as shown in Table 44, wood poles make up the vast majority of the pole fleet.

Table 44 – Number and Age by Pole Material

Material	Number of Poles	Average Age
Wood	1,597,000	39.7
Steel	6,000	19.6
Concrete	2,000	29.2
Composite	2,000	6.9

Hydro One's asset strategy for the management of distribution poles centres on condition information collected through the line patrol program. Once a pole has been assessed to be in poor condition it is planned for replacement.

Preventative Inspection and Maintenance Program

Typical pole inspections begin with a visual assessment of the pole's current condition. Items the inspector would identify are the severity of woodpecker damage, mechanical damage, and insect damage. The inspector would also determine if the pole is severely leaning and report on the amount of surface decay.

The inspector will also perform a hammer test on every pole inspected to ensure the soundness of the pole. In some situations the pole may be bored to measure the remaining shell thickness. All of this condition data is used for prioritizing pole replacements.

During the inspections other defects associated with the line are collected at the pole level such as a broken guy wire. These issues are corrected as part of the defect correction program unless there are capital replacement plans for the pole.

All data collected during these inspections is recorded in SAP and is used for planning replacements and defect corrections. During the data collection, the inspector will confirm all characteristic data about the pole is correct and up to date.

Optimization, Prioritization and Scheduling

Hydro One's asset strategy for the management of distribution poles centres on their condition and the forecast condition using demographics of the population. The condition information is used in the selection and prioritization of specific poles to be replaced annually, whereas the demographic profile enables the projection of long term pole replacement rates. Hydro One endeavours to replace poles before they fail, pose a safety hazard, or cause a service interruption. Where possible, these replacements are

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: November 11, 2016

Re: Application for Distribution Rates 2018 to 2022

Attached for information is a summary of progress to date of the Distribution Investment Plan for the five year Distribution rate filing that is expected to be filed on March 3rd, 2017. The information is provided for feedback and input.

Significant inclusions/changes since the last Board meeting include:

1. A potential path to accomplish a 2018 rate increase of 5.4% (average of 3.4% over 5 years).
2. Detailed analysis of the effects of various options on customer bills and reliability.
3. Data on asset replacement rates and impacts on asset condition.
4. Analysis of productivity initiatives and outcomes on capital and OM&A
5. Summaries of customer feedback and the impact of such feedback on the plan.
6. Some history of OEB decisions to provide context on OEB expectations for this filing.

For the last several months, our teams have worked diligently to analyse trade-offs between customer and reliability impacts and customer bill impacts. In working to the optimum outcomes, we have considered overall reductions in the capital program, short-term capital reductions and more aggressive and targeted cost reduction to further reduce the overall bill impact arising from OM&A and corporate costs. Our focus was to find ways to reduce the average bill impact over the five year period, but also reduce the first year (2018) bill impact that already has non-actionable rate increases of 5.1% included. Our latest iteration has succeeded in adding only 0.3% in rate increases to the minimum bill impact in 2018.

The analyses provided are for feedback only. Management is not making a recommendation at this time. We will incorporate your feedback into the further analysis that we continue to perform, and expect to provide a final recommendation that will be included in a detailed business plan for Board approval at the December 2016 meeting.

We have attempted to keep the analysis as clear as possible, while providing relevant data.The subject is complex, and I would be pleased to discuss or answer questions of clarification before the meeting.

Yours sincerely,

Michael Vels
Chief Financial Officer

Investment Management has further refined their work, and have outlined further options for consideration. Firstly, they assessed what would be required to achieve the lowest 2018 rate increase without material disruption to our operations. This is presented as the "Plan C" scenario, a top down assessment of alternatives, and is not fleshed out the same amount of detail as the Plan A and B scenarios. Our conclusion is that this option as a whole is not viable due to the material system and reliability impacts - degradation of approximately 2% in both SAIDI and SAIFI - that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition. However, a subset of options were also considered and are included in a scenario labelled here as "Plan B Modified." These options reduce the immediate impact on rates in 2018, to 5.4%. These options are indented to hold reliability risk constant, but may be justified by the positive effect on rates.

In the remainder of this note, we have outlined elements of the process followed and some more detail to illustrate the outcomes of each option. We are presenting these analyses for input and feedback, and will be finalising and presenting our recommendations for the Distribution rate filing in December, when we request approval of the Company's business plan. This business plan will then form the basis for the rate filing and related evidence, to be filed on March 3rd, 2017.

C. INVESTMENT PLANNING PROCESS

Hydro One's investment planning process is based on ISO 55000 principles, which are best practices for holistic Asset Management. The process takes identified asset needs, converts them into candidate investments, and then optimizes them based on their contribution to business objectives to yield an investment plan.

Business Objectives	Description
Customer 20 pts	• Improve customer satisfaction. • Engage with customer consistently and proactively.
Safety 20 pts	• Drive towards an injury-free work place. • Eliminate public safety incidents
Employee 10 pts	• Achieve and maintain employee engagement.
Reliability 15 pts	• Maintain current level of distribution system reliability relative to distribution peers.
Environment 10 pts	• Sustainably manage our environmental footprint.
Productivity 15 pts	• Actively control and lower costs through OM&A and capital efficiencies.
Shareholder Value 10 pts	• Ensure compliance with all codes, standards and regulations. • Achieve the ROE allowed by the OEB.

Initial guidance, in addition to these business objective weighting factors, was provided to planners in February 2016 to build their plans with the following considerations:

THUNDER BAY HYDRO
2015 ASSET CONDITION ASSESSMENT

August 11, 2016

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

Thunder Bay Hydro
2015 Asset Condition Assessment

Kinectrics Report: K-418914-RA-0001-R00

August 11, 2016

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Revision History

Revision Number	Date	Comments	Approved
R00	August 11, 2016	Final Report	Yury Tsimberg

SUMMARY

In 2015 Thunder Bay Hydro Electricity Distribution Inc. (TBH) determined a need to perform a condition assessment of its key distribution assets. This would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, and facilitate the development of a Distribution System Plan.

The asset groups included in the 2015 asset condition assessment (ACA) were as follows: substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at this year, this amounts to over 450 poles. Approximately 9% of 4 kV wood poles were also flagged for action this year. Because of the considerably smaller population, however, this equates to just over 230 poles. Approximately 19% of pole mounted transformers were classified under the very poor category. As such, 170 transformers need to be addressed.

Many asset groups (i.e. distribution transformers, overhead switches, and underground cables) had only age data available. Data gaps for these and all other asset categories were identified. It is recommended that TBH begin collecting information to fill these data gaps and to use such information for future assessments.

It is important to note that the flagged for action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Distribution System Plan.

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I INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (TBH) is a private local distribution company responsible for distributing electricity to over 50,000 customers via a network of more than 1,300 kilometers of overhead and underground power lines in the City of Thunder Bay. TBH is owned by the City of Thunder bay and is operated by the Thunder Bay Hydro Board.

TBH recently recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. Such an assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan.

In 2015 TBH engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on TBH's key distribution assets. This report presents the results of the study.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
    - 4 kV
    - 12 kV
- Breakers
- Wood Poles
    - 4 kV
    - 25 kV
- Distribution Transformers
    - Pad Mounted Transformers
    - Pole Mounted Transformers
    - Vault Transformers
- OH Switches
    - 4kV In-Line
    - 4kV Manual Air Break
    - 12 and 25kV In-Line
    - 12 and 25kV Manual Air Break
    - 25kV Motorized Load Break
- Underground Switches
    - 25kV Underground Load Break Switches
- Underground Cables
    - 4kV
    - 12 and 25kV

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included:
  - Health Index formula
  - Age distribution
  - Health Index distribution
  - Condition-based Flagged For Action Plan
  - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis.

II ASSET CONDITION ASSESSMENT METHODOLOGY

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weights, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m,\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS_m = \frac{\sum_{n=1}^{\forall n} \beta_n (SCPS_n \times WSCP_n) \times DR_n}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)} \times DR_m$$

Equation 2

CPS	Condition Parameter (CP) Score, 0-4
WCP	Weight of Condition Parameter
α_m / β_n	Data availability coefficient for condition parameter (1 if input data available; 0 if not available)
SCPS	Sub-Condition Parameter (SCP) Score, 0-4
WSCP	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. In the Kinectrics methodology, a condition criteria scoring system of 0 through 4 is used. A score of 0 is the "worst" possible score; a score of 4 is the "best" score. I.e. $CPS_{max} = SCPS_{max} = 4$.

Note: From the formula, it can be seen that each parameter (condition or sub-condition) will have the following properties:

1. Weight
2. Availability coefficient (1 if asset has data for such parameter available; 0 otherwise)
3. Score (real value from 0 through 4)
4. Multiplier (real value)

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 Condition Based Flagged for Action Plan

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f	= cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} = 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

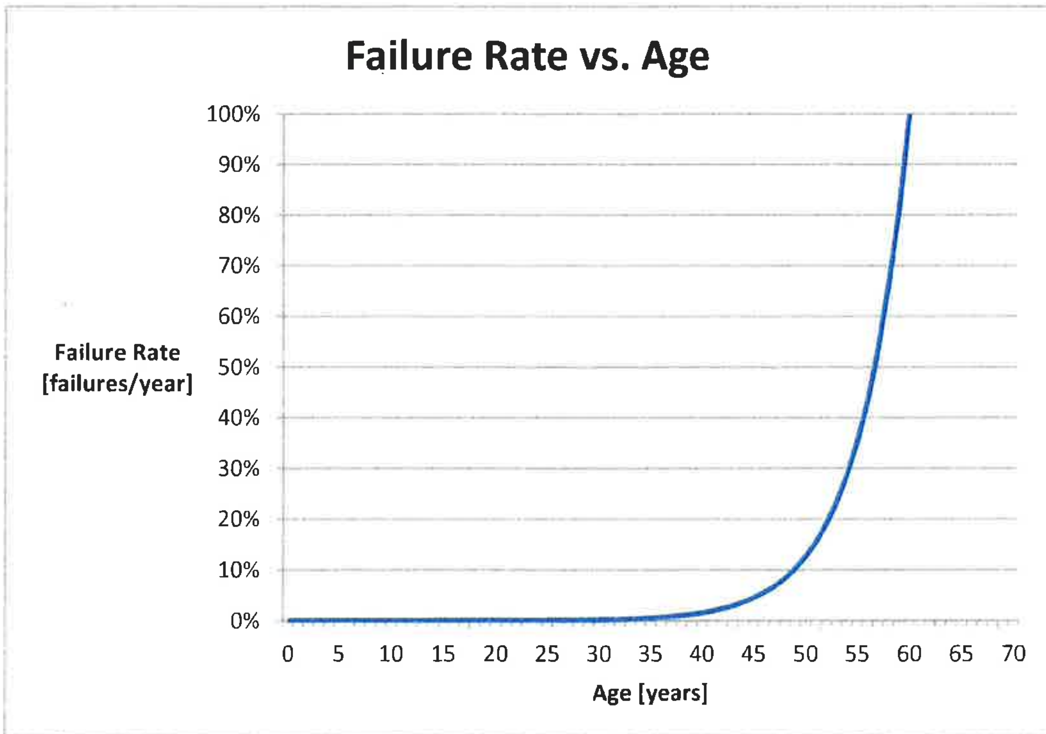

Figure II-1 Failure Rate vs. Age

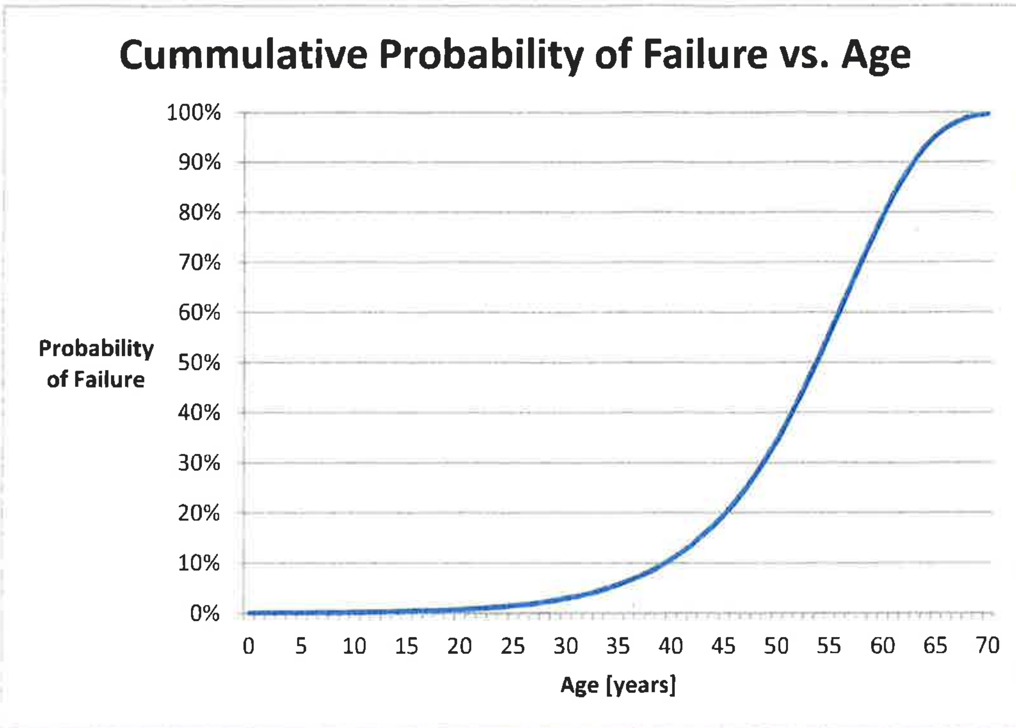

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

The Levelized Flagged for Action plan smooths or levelizes the peaks and valleys of the flagged for action plan.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

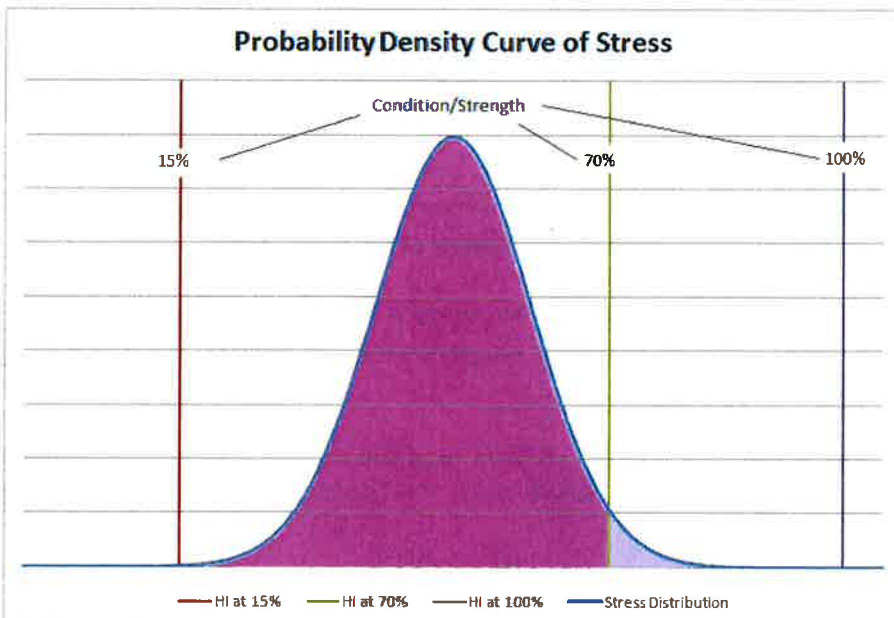

Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

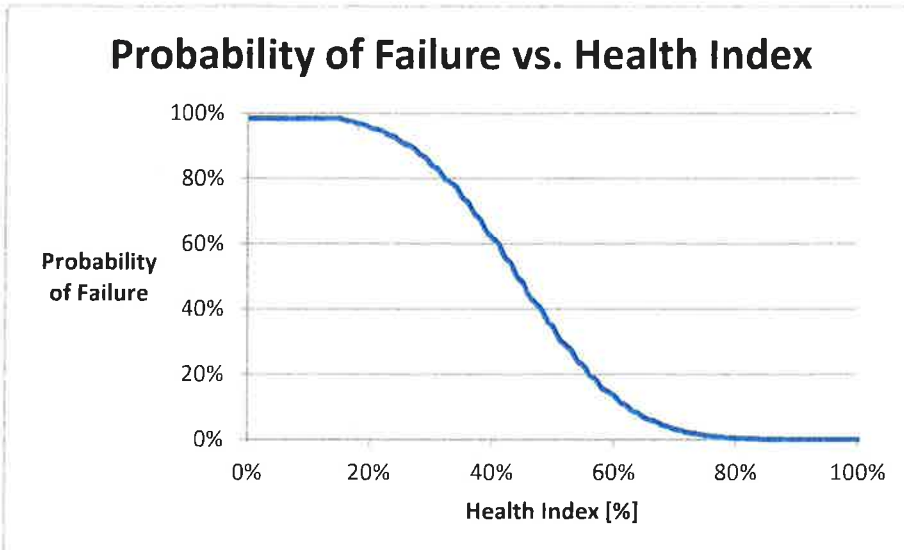

Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be 1.43*0.7 = 1 and it will be flagged for action.

II.3 **Data Assessment**

The condition data used in this study were provided by TBH and included the following:

- Test Results (e.g. Oil Quality, DGA, PCB)
- Inspection Records via Non-Conformance Logs
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m}(DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m}(WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n}\beta_n \times WCFn}{\sum_{n=1}^{\forall n}(WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	Name		n	Name		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

$$DAI_{CP1} = (1*1) / (1) = 1$$
$$DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545$$
$$DAI_{CP3} = (0*1) / (1) = 0$$

$$\begin{aligned} DAI &= (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3) \\ &= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3) \\ &= 35\% \end{aligned}$$

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on TBH's available data. There are additional parameters or tests that TBH may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	★★★
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	★★
Low	Helpful data; least indicative of asset deterioration	★

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Tank Corrosion	Physical Condition	★★	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and average age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in **Error! Reference source not found.**. Note that the Health Index distribution percentages are based on the asset group's sample size.

The 4 kV underground cables, on average as an asset group, were found to be in the worst condition. A total of 34% were in very poor condition, where another 14% were found in poor condition. This is primarily because with the average age of the population at 43 years, the population is fairly old. However, since the population size is minimal (44 conductor-km), this is not a significant concern.

A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Many distribution transformers were also found to be in bad condition. Approximately 9%, 19%, and 8% of pad-mounted, pole-mounted, and vault transformers respectively were classified under the very poor category. These include units that are leaking and that contain PCBs.

The wood pole asset category is also concerning. A total of 10% of all wood poles are in poor or very poor condition.

III.2 Condition-Based Flagged for Action Plan

When there is a large quantity of assets that are at or near the end of their service lives, there may be large quantities of assets flagged for action in the first year. This represents a "backlog" of assets that required attention from past years. As it would not be feasible or practical for a utility to address all assets immediately, a levelized flagged for action plan, where quantities to address are spread over subsequent years, is also given. The unlevelized and levelized flagged for action plans are shown in Table III-2, Table III-3, Figure III-6, and

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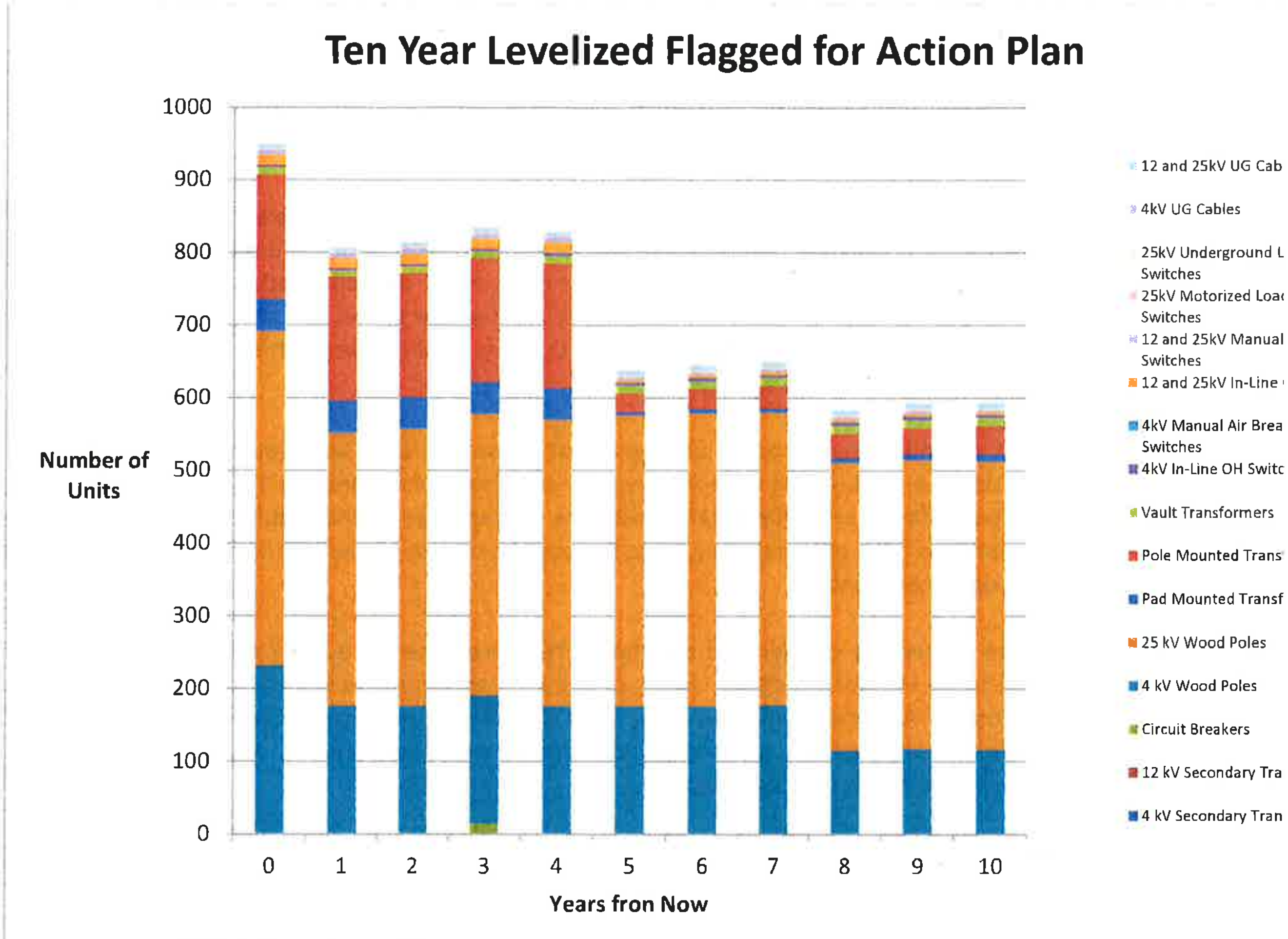

Figure III-7.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year (per the Levelized Plan in Table III-2), this amounts to over 450 poles. Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population, however, this equates to just over 230 poles. Pole mounted transformers also have large quantities requiring action in year 1. Per the Levelized Plan, more than 170 transformers (4% of the population) are flagged.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age
Station Transformers	All	23	23	88%	0%	4%	9%	4%	83%	52
	4 kV	17	17	86%	0%	6%	6%	12%	76%	54
	12 kV	6	6	94%	0%	0%	0%	0%	100%	47
Breakers	Breakers	77	77	72%	0%	18%	23%	12%	47%	56
Wood Poles	All	19813	19813	75%	1%	9%	34%	21%	34%	28
	4 kV	3862	3862	63%	4%	22%	39%	21%	15%	36
	25 kV	15951	15951	77%	< 1%	6%	33%	21%	39%	27
Distribution Transformers	Pad Mounted Transformers	2206	2206	87%	9%	1%	2%	12%	75%	25
	Pole Mounted Transformers	4143	4141	81%	19%	1%	1%	1%	77%	29
	Vault Transformers	285	285	78%	8%	3%	15%	26%	49%	33
OH Switches	All	729	305	76%	14%	5%	10%	12%	60%	32
	4kV In-Line	101	46	71%	26%	0%	9%	11%	54%	32
	4kV Manual Air Break	7	2	70%	0%	50%	0%	0%	50%	32
	12 and 25kV In-Line	399	148	80%	11%	7%	5%	8%	70%	31
	12 and 25kV Manual Air Break	183	74	78%	14%	4%	7%	9%	66%	33
	25kV Motorized Load Break	39	10	67%	10%	20%	20%	10%	40%	39
Underground Switches	25kV Underground Load Break Switches	80	30	81%	0%	13%	17%	3%	67%	31
Underground Cables*	All	432	374	80%	3%	3%	31%	4%	60%	29
	4kV	44	29	44%	34%	14%	21%	0%	31%	43
	12 and 25kV	387	344	84%	< 1%	2%	32%	4%	63%	28

* data is in conductor-km

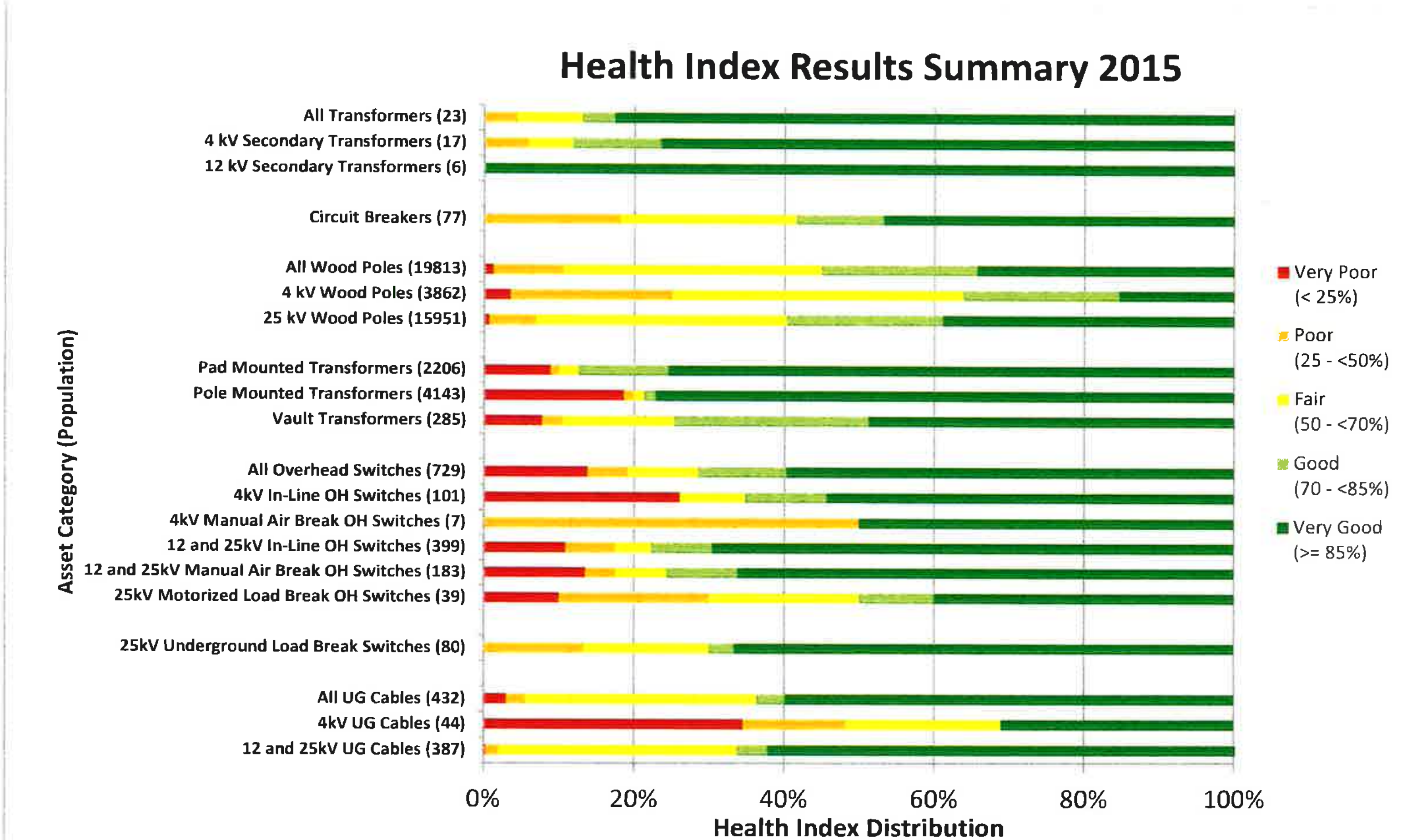

Figure III-5 Health Index Results Summary (Graphical)

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Table III-2 Total Year 1 and 10-Year Total Flagged for Action Plan

Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
Substation Transformers	4 kV Secondary Transformers	0	0%	3	18%	0	0%	3	18%	proactive
	12 kV Secondary Transformers	0	0%	0	0%	0	0%	0	0%	proactive
Circuit Breakers	Circuit Breakers	0	0%	14	18%	0	0%	14	18%	proactive
Wood Poles	4 kV Wood Poles	364	9%	1636	42%	232	6%	1636	42%	proactive
	25 kV Wood Poles	544	3%	3964	25%	460	3%	3964	25%	proactive
Distribution Transformers	Pad Mounted Transformers	204	9%	240	11%	44	2%	240	11%	proactive
	Pole Mounted Transformers	625	15%	974	24%	171	4%	974	24%	reactive
	Vault Transformers	14	5%	93	33%	10	4%	93	33%	reactive
Overhead Switches	4kV In-Line OH Switches	3	3%	36	36%	3	3%	36	36%	reactive
	4kV Manual Air Break OH Switches	0	0%	4	57%	0	0%	4	57%	reactive

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Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
	12 and 25kV In-Line OH Switches	30	8%	92	23%	15	4%	92	23%	reactive
	12 and 25kV Manual Air Break OH Switches	20	11%	36	20%	5	3%	36	20%	reactive
	12 and 25kV Motorized Load Break OH Switches	0	0%	16	41%	2	5%	16	41%	reactive
Underground Switches	25kV Underground Load Break Switches	0	0%	13	16%	1	1%	13	16%	reactive
Underground Cables*	4kV UG Cables	2	5%	4	9%	1	2%	4	9%	reactive
	12 and 25kV UG Cables	4	1%	59	15%	6	2%	59	15%	reactive

* data is in conductor-km

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K-418914-RA-0001-R00

Table III-3 Ten Year Flagged for Action Plan

Replacement Year	Type (L = Levelized; Blank = Unlevelized)	Asset Category: Substation Transformers		Circuit Breakers	Wood Poles		Distribution Transformers			Overhead Switches					Underground Switches	Underground Cables*	
		4 kV Secondary Transformers	12 kV Secondary Transformers	Circuit Breakers	4 kV Wood Poles	25 kV Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line OH Switches	4kV Manual Air Break OH Switches	12 and 25kV In-Line OH Switches	12 and 25kV Manual Air Break OH Switches	25kV Motorized Load Break OH Switches	25kV Underground Load Break Switches	4kV UG Cables	12 and 25kV UG Cables
0	L	0	0	0	232	460	44	171	10	3	0	15	5	2	1	1	6
		0	0	0	364	544	204	625	14	3	0	30	20	0	0	2	4
1	L	0	0	0	177	375	44	171	8	3	0	15	5	2	1	1	5
		0	0	0	253	473	7	130	9	2	0	13	5	0	5	0	4
2	L	0	0	0	176	381	44	171	9	3	0	15	5	3	1	1	6
		0	0	0	210	447	3	42	10	7	0	8	2	4	0	1	6
3	L	1	0	14	176	387	44	171	9	3	0	15	5	2	1	1	6
		1	0	14	182	424	2	30	8	3	0	22	0	8	1	0	7
4	L	0	0	0	176	394	44	171	10	4	1	15	5	2	1	1	6
		0	0	0	153	412	2	28	10	2	0	0	0	0	0	0	7
5	L	0	0	0	176	400	5	26	10	3	1	4	2	2	2	1	7
		0	0	0	132	409	5	28	9	2	0	8	5	0	1	0	8
6	L	0	0	0	176	403	6	28	10	4	1	4	2	2	2	1	7
		0	0	0	119	411	6	27	12	7	0	3	2	4	3	0	8
7	L	2	0	0	176	402	6	31	11	3	1	4	3	2	2	1	7
		2	0	0	112	416	5	32	10	3	0	5	2	0	2	0	8
8	L	0	0	0	116	395	7	33	11	4	1	4	2	2	2	1	7
		0	0	0	111	428	6	32	11	7	4	3	0	0	1	1	7
9	L	1	0	0	117	397	8	36	11	4	1	4	3	2	2	1	7
		1	0	0	114	425	5	36	11	2	0	3	5	0	1	0	9
10	L	0	0	0	117	396	10	39	11	3	1	4	2	1	2	1	7
		0	0	0	115	418	9	39	12	3	0	0	0	0	1	1	7

* data is in conductor-km

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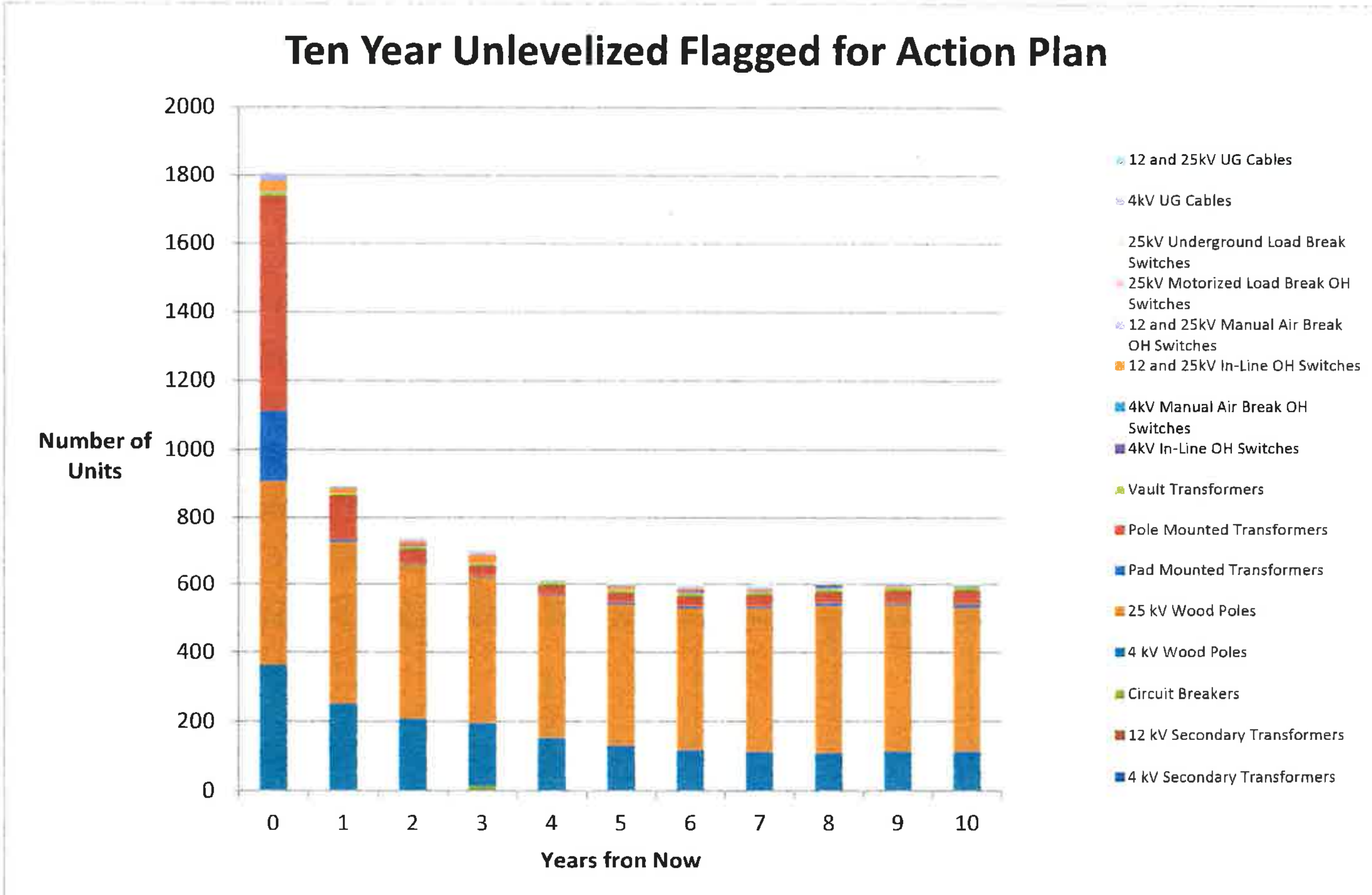

Figure III-6 Ten Year Unlevelized Flagged for Action Plan (Graphical)

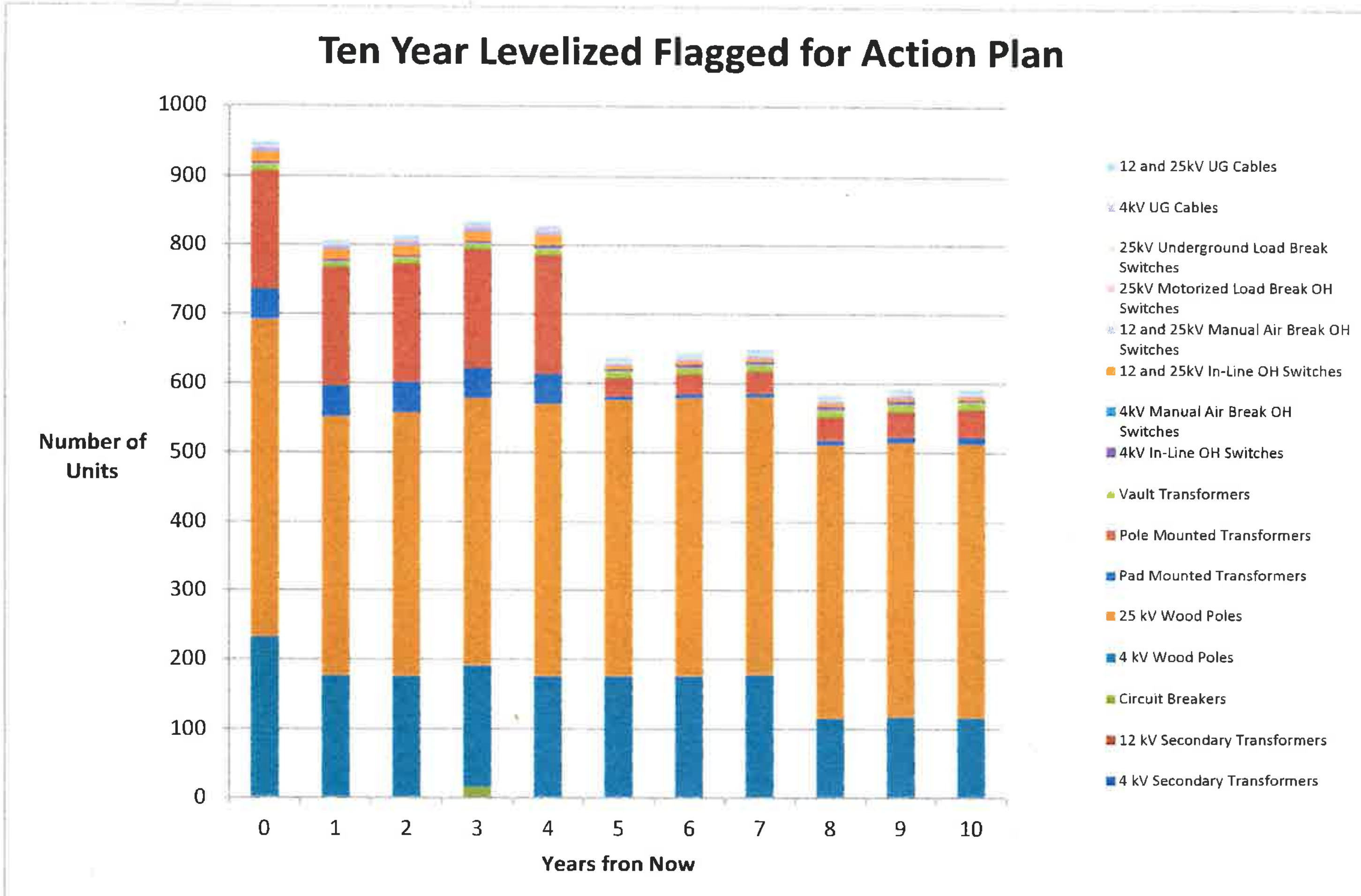

Figure III-7 Ten Year Levelized Flagged for Action Plan (Graphical)

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III.3 **Data Assessment Results**

As mentioned described in Section II.3, the assessment of the available data was done by looking at the data availability indicator (DAI) and data gaps. Recall that the DAI is measurement that is relative to the information that TBH currently collects, whereas data gaps are information that TBH does not collect. As such, even if an asset group has a high DAI, this does not mean information for this asset group is complete. i.e. if there are numerous data gaps, the degree of confidence that the Health Index reflects true condition may still be low. Table III-4 shows the average DAI for each category. The Data Gap column indicates the extent of the data gap (i.e. "high" indicates that a significant amount of condition information can be collected for future assessments). Overall assessments for each asset category are summarized below. Additional details, including prioritized data gaps, are given in the data gap sections of Appendix A: Results for Each Asset Category.

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. Data that would be helpful for future assessments include power dissipation factor tests, inspection and/or corrective maintenance records.

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the operation counts, fault interruption counts, and fault level interrupted.

Age and overall risk rating based on inspection records were available for wood poles. Data gaps include more detailed inspection records and strength tests that give an objective, quantified assessment of the condition of wood poles.

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Only age and PCB content were available for pole-mounted and vault transformers. Loading and inspection/corrective maintenance information related to transformer condition (e.g. leaks, tank/enclosure condition, corrosion, connections).

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Underground cables had only age information. However, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan

Delta). Such information will provide good, objective condition data as input into the Health Index.

Table III-4 Data Assessment

Asset Category		Average DAI	Data Gap
Station Transformers	All	93%	Low-Medium
	4 kV	92%	
	12 kV	93%	
Breakers	Breakers	61%	Low-Medium
Wood Poles	All	100%	Medium-High
	4 kV	100%	
	25 kV	100%	
Distribution Transformers	Pad Mounted Transformers	85%	Low-Medium
	Pole Mounted Transformers	100%	Medium-High
	Vault Transformers	100%	Medium-High
OH Switches	All	42%	High
	4kV In-Line	46%	
	4kV Manual Air Break	29%	
	12 and 25kV In-Line	37%	
	12 and 25kV Manual Air Break	40%	
	12 and 25kV Motorized Load Break	26%	
Underground Switches	25kV Underground Load Break Switches	38%	High
Underground Cables	All	48%	High
	4kV	65%	
	12 and 25kV	47%	

IV CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for TBH's key distribution assets, namely substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.

2. Of all the asset groups, 4kV underground cables were found, on average, to be in the worst condition. A total of 48% were found to be in poor or very poor condition. However, because of the small population, this is not a significant cause for concern.

3. A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Because the population of switches is relatively small, the number of assets flagged for action is not significant.

4. Approximately 19% of pole mounted transformers were classified under the very poor category. Per the levelized flagged for action plan over 170 transformers require action in the first year.

5. In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year, this amounts to over 450 poles.

   Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population than the 25 kV poles, however, this equates to just over 230 poles.

6. Age and inspection information were available for substation transformers, breakers, wood poles, and pad-mounted transformers. Additionally substation transformers had loading and oil tests. Only age was available for pole-mounted transformers, vault transformers, overhead and underground switches, and underground cables. Further, the age was only available for less than half of the switches and cables.

7. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. Data for all condition parameters used in the HI formulas should be collected for all assets. The low DAIs of switches and cables are of particular concern.

8. Data gaps were identified for each asset category, prioritized in the order of importance, in the Appendix of this report. It is recommended that the data be gathered in prioritized manner. Data may be gathered from inspections or corrective maintenance records. Additional sources of data would come from testing (e.g. pole strength testing or cable testing).

9. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is

recommended that TBH begin collecting failure information so failure models can be developed and used in future assessments.

10. It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Asset Management Plan.

V REFERENCES

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Gompertz, "On the Nature of the Function Expressive of the Law of Human Mortality, and on a New Mode of Determining the Value of Life Contingencies," Philosophical Transactions of the Royal Society of London, Vol. 115, pp. 513-585, 1825

Hjartarson T, Jesus B, Hughes D.T., Godfrey R.M., "The Application of Health Indices to Asset Condition Assessment", presented at IEEE-PES Conference in Dallas, September 2003.

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Makeham, "On the Law of Mortality and the Construction of Annuity Tables," J. Inst. Actuaries and Assur. Mag. 8, 301-310, 1860

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Wang F., Lotho K., "Condition Data Requirements for Distribution Asset Condition Assessment", CEATI International, 2010

Willis H.L., Welch G, Randall R. Schrieber, " Aging power delivery infrastructures", Marcel Decker Inc., 2001

OEB Staff Interrogatory # 119

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 3.8 Page: 2881-2885
(5.4.5.2) Attachments: Material Investments, ISD: GP-35 Asset Analytics Risk Factor

Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 11)

The Auditor General's report recommended the following:

> *"To ensure that management decisions on replacing distribution system assets are made using reliable and complete information, Hydro One should take the actions needed to ensure its Asset Analytics system provides timely, reliable, accurate and complete information on the condition of assets."*

Interrogatory:

a) Please provide information on how Hydro One has improved the reliability and complete information of the Asset Analytics system.

b) Please provide the Asset Analytics algorithm and Asset Analytics Risk Factors currently used for this application and the weighting used for each factor. Please also provide the justification of each factor and weighting.

c) What is considered an acceptable Asset Risk score and what is considered an unacceptable Asset Risk score?

d) Please provide how much weight is given to the outcome of the Asset Analytics results during the planning of maintenance programs and future capital investment planning.

e) Please provide in Excel format the Asset Analytic Risk output for all station reclosers/breakers, station transformers, and mobile unit substations.

Witness: GARZOUZI Lyla

Response:

a) Hydro One has been conducting workshops to review, identify and address data needs and accountabilities in the SAP asset registry. As of the end of 2017, distribution station assets have had a full review of data needs and accountabilties, and are planned to complete the activities to address ongoing monitoring and processes in 2018. Distribution line asset data will begin preliminary review in 2018.

b) The specific Asset Analytics algorithms for each Risk Factor used in this application for poles and specific stations assets, as described here.

<u>Demographics Risk Factor:</u>

Asset Type	Supporting Factor	Supporting Factor Weight	Description
All	Age of Asset	100%	A comparison of the age of an asset relative to the expected service life of the asset type.

<u>Condition Risk Factor:</u>

Asset Type	Supporting Factor	Supporting Factor Weight	Description
Station Transformer	Notification Count	10%	Number of defect notifications for a specific asset relative to the average number of defect notifications for assets of that type.
	Oil Top Up	5%	Number of oil top ups.
	Dissoved Gas Analysis	25%	Results of a DGA test - detection of thermal and electrical faults.
	Standard Oil Test	25%	Results of a Standard Oil Test.
	Furan	25%	Results of Furan Testing – related to insulation degredation.
	Doble Test	10%	Results of Doble Testing – related to insulation degredation.
Station Recloser	Counter reading	75%	Nuber of operations since last overhaul relative to manufacturer recommended number of operations.
	Notifications	25%	Presence of notification indicating the asset required attention.
Station Site Structure	Structure Condition	60%	Results of latest condition assessment.
	Grounding Condition	10%	Results of latest condition assessment.
	Footing Condition	30%	Results of latest condition assessment.

Wood Pole*	Shell Thickness	N/A	Thickness of shell.
	Hammer Test	N/A	Results of latest hammer test.
	Visual Damage Assessment	N/A	Results of latest visual assessment.
	Woodpecker damage	N/A	Results of latest visual assessment.
	Pole Defects	N/A	Number of defect notifications for a given asset.

** Note: Wood pole supporting factors are considered individually, and do not have relative weights.*

Criticality Risk Factor:

Asset Type	**Supporting Factor**	**Supporting Factor Weight**	**Description**
Station	Downstream customers	70%	The number of customers supplied by the station.
	Critical customers	15%	The number of critical customers supplied by the station.
	Sensitive customers	15%	The number of sensitive customers supplied by the station.
	Redundancy	(+20%)	Move up factor – if there is no redundancy for the station, the criticality is increased.
	Environment	(+10%)	Move up factor – if the station is located in an urban environment, criticality is increased.

c) Asset risk assessment scores are not classified as "acceptable" or "unacceptable". Rather, they provide a means to compare specific aspects of asset risk between assets of the same type.

d) As described on page 12 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1 the results of asset risk assesments are used in combination with a number of other factors in assessing overall asset needs. Specific weightings for individual asset risk asessments are not strictly defined when determining individual asset needs.

e) Please refer to Attachment 1 of this response for the Asset Analytics risk output for all station transformers, reclosers, breakers in excel format. Asset Analytics algorithms currently do not exist for MUS trailers; therefore no asset analytic risk output is provided for mobile unit substations.

UNDERTAKING – JT 3.1-11

Reference
I-24-AMPCO-23 (c)

Preamble: HONI indicates that most asset groups have data availability levels below 100%.

Undertaking
i. Please list the asset groups that have data availability levels equal to 100%.

ii. Please list the asset groups that have data availability levels of less than 50%.

iii. Please list the asset types that have data availability levels of greater than 50% but less than 75%

iv. Please list the asset types that have data availability levels of greater than 75% but less than 100%.

Response
Please see the table below for the station assets data availability:

Asset Type	Data Availability Level
i) The asset types that have data availability levels equal to 100%.	
Station Structures	100%
MUS structures	100%
ii) The asset types that have data availability levels of less than 50%.	
Circuit Breakers –All	38%
iii) The asset types that have data availability levels of greater than 50% but less than 75%.	
None	
iv) The asset types that have data availability levels of greater than 75% but less than 100%	
Station Transformers	89%
Mobile Unit Substation (Transformers)	87%
Station Reclosers - All	84%

All lines assets are inspected regularly as part of the distribution line patrol. During these inspections, condition is recorded on an exception basis – assets in good conditions do not have defect reports associated with them. For this reason, condition data is generally limited to assets in poor condition and therefore condition data availability is less than 100%.

Witness: GARZOUZI Lyla

95

UNDERTAKING – JT 3.1-12

Reference
I-24-AMPCO-23 (f)

Preamble: HONI indicates that not all asset types or sub-types have condition algorithms.

Undertaking
Please explain further what this means and the resulting impact on the condition assessment of the asset.

Response
Not all asset types or sub-types have condition algorithms that are used to determine if an asset is at the end of its useful life. When defects on assets with no condition algorithms are identified, they are addressed appropriately.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-14

Reference

I-24-AMPCO-25

Preamble: HONI provided details on planned asset replacements.

Undertaking

i. Please clarify if the planned asset quantities provided include planned replacements under the System Renewal investment category only, or if planned asset replacements under System Access and System Service categories are also included.

ii. If the table reflects System Renewal planned investments only, please provide an updated excel table to show planned replacements under all three asset investment categories: System Renewal, System Access and System Service.

Response

i. These include planned replacements that are targeted at end of life asset categories under investments pertaining to System Renewal only; with the exception of station assets (which included planned replacements under System Service: SS-02 System Upgrades Driven by Load Growth) and AMI assets (which included planned meter replacements under System Access: SA-02 Metering Infrastructure Sustainment Program and SA-04 New Load Connections, Upgrades, Cancellations and Metering, as well as System Service: SS-01 Remote Disconnection / Reconnection Program).

ii. Hydro One does not track the quantity of planned asset replacements that are completed under all investment categories. System Access and System Service categories of investments are not primarily driven by end of life assets.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-18

Reference

I-29-AMPCO-27 (b)

Preamble: HONI indicates it could not provide the asset unit replacement levels by investment plan scenarios for total line component category as volumes are not available as they are dissimilar units replaced as part of both individual programs and as part of refurbishment projects.

Undertaking

i. Please explain this statement further.

ii. Please provide the asset groups included under Other Line Equipment.

iii. Please explain how HONI determined the spending for "Other Line Equipment" under each investment plan scenario.

Response

i. The "Other Line Components" category described in Section 2.4 of the DSP (Exhibit B1-1-1) refers to outages caused by the failure of any line component other than poles. As such, it includes outages due to the failure of a high number of different equipment types, most of which are not replaced as part of any specific program. For this reason, the total volume of component replacements is unavailable.

ii. Any and all lines components other than poles are included under "Other Line Components".

iii. As defined in Section 2.4 of the DSP (Exhibit B1-1-1), and for the reasons described in part (i) above, there is no defined spending level for "Other Line Components".

These components are replaced as part of a number of investments described in the DSP, including but not limited to, the "Distribution Lines Planned Component Replacement Program" described in Investment Summary Document SR-10, the "Distribution Lines Sustainment Initiatives" described in Investment Summary Document SR-12, and the "Life Cycle Optimization & Operational Efficiency Projects" described in Investment Summary Document SR-13.

Witness: JESUS Bruno

single phase, not sure that 80% of the replacements are single phase – may be replacing with more than you think.

- **Consider the type of programs being used for pole replacement**. There are 5 different programs that replace poles. For example, service upgrades can be part of this if the pole is replaced as part of the service upgrade because of its condition. Line refurbishment is where you rebuild the whole line because you bypass the threshold for the amount of poles on the line that need to be replaced, so this is a different program. All poles on the line need to be replaced whether each individual one needs to be replaced or not. Other things that may drive the replacement program include the engineering standards between the old pole and the new pole e.g. the height of the old pole vs. the existing pole. If you don't create this kind of context for the analysis, the cost of pole replacement may look artificially high, because it does not take into account all the pole replacement that was pushed into other programs.
- **Consider adding other criteria that appear to missing, such as density, remoteness, and the median distance between the pole replaced and the service centre**. Given that the end product of the exercise is the unit cost for pole replacement, a lot of these criteria seem to be more related to what drives the number of poles that get replaced in a particular time frame, which is not relevant to the key metric (unit cost).

Questions of Clarification

Cost Drivers

- 90% of Ontario is either rural or really remote - how have you factored this in as a cost driver? Or is the cohort selection process going to take care of that? *We intend to gather the information about what is being replaced, such as whether they are in the urban or rural area. In terms of the drivers, some of those make a difference in the sense that if you are replacing 4% a year you're not going to let them get very old versus if you are replacing 1% a year you're likely to have a lot more failures.*
- I thought you weren't measuring cost of pole replacements? *It's not the core function, but we will be asking for those volumes.* You can rest assured that we'll be 1% or less, not 4%.
- I don't think that's correct that the whole system is remote, there are towns like Ancaster and Kingston, and all sorts of places like that served by Hydro One, you need to let the data tell you about this.
- I want to confirm what you are studying: The question is: How efficiently is Hydro One replacing the poles in total, not the crews individually – you are looking at the entire strategy, there are a lot of different drivers in there in terms of cost impact. *Correct, this is what we are measuring, including all the factors outside of the crew replacing the pole.*

Next Steps in the Study

Ben Grunfeld from Navigant and Ken Buckstaff from First Quartile reviewed the final slides regarding Next Steps for their study. Following their presentation participants asked questions of clarification and provided feedback on the proposed approach. A summary of the questions and feedback is provided below. Please note that responses provided to questions and comments are noted in *italics* immediately following each question or comment.

Questions of Clarification

- Looking at the previous version of the presentation – where your second bullet says finalize peer group selection metrics and identify candidate. Have you finalized your peer group selection metrics? It was my understanding that what was presented here was a sample, as some factors to consider, not the final list, but now I think you're saying that this is your final

EXECUTIVE SUMMARY

In the Ontario Energy Board's (OEB's) decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, the Board directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". Hydro One was also directed to "report on the results of this work with the corresponding analysis as part of its next rates application". Through a competitive procurement process, Hydro One Networks Inc. (Hydro One) engaged the consortium of Navigant Consulting Ltd. (Navigant) and First Quartile Consulting (1QC) to conduct this benchmarking study.

This report provides an overview of the approach, including the processes of selecting and recruiting utilities to participate in the study, assembling appropriate performance metrics, and gathering and analysing the data. The study provides insights into both the costs incurred by Hydro One and the practices used for the execution of pole replacement and substation refurbishment. Primary findings from the study for both the pole replacement and station refurbishment activities are presented below.

Pole Replacement

1. Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles.
2. Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections with some light physical inspections, while the others typically perform more rigorous physical inspections and testing.
3. The replacement rate for Hydro One is slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest; on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group.
4. Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone premature replacement of poles.

Substation Refurbishment

1. Station refurbishment activities are varied within and across utilities.
2. Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.
3. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.
4. Navigant and First Quartile Consulting believe that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.
5. Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.
6. Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.

Recommended Actions

In its request for proposals, Hydro One indicated that the study should produce recommendations that Hydro One could act upon to close gaps to best practice and improve the efficiency of its operations. Several recommendations were developed for each of the two areas under study.

Pole Replacement

The key recommended actions for pole replacement are outlined below.

1. Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2. Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria
3. Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4. Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

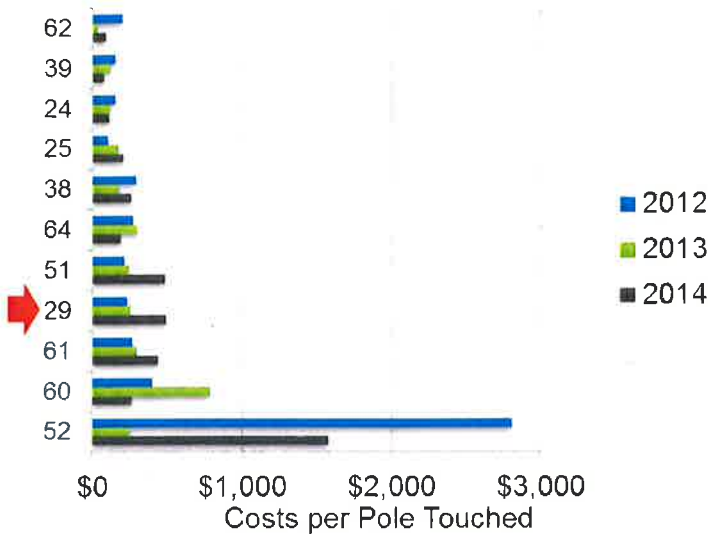
Substation Refurbishment

The key recommended actions for substation refurbishment are outlined below.

1. Consider implementing a formal data governance process for equipment performance and maintenance data, and incorporating that information into the asset condition scoring and project planning process.
2. Enhance cost and work completion reporting for individual projects, and implement a formal change control process.
3. Develop and implement a more comprehensive set of key performance indicators including in-progress project cost performance measures and assessments of project/program impacts on substation reliability, maintenance costs and overall asset health.

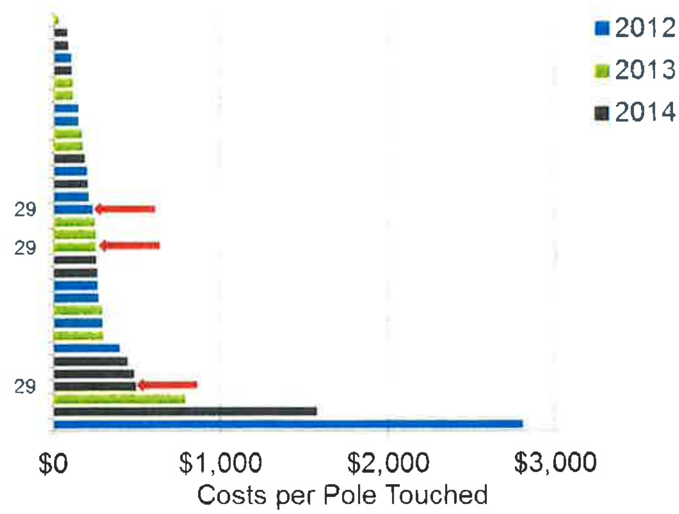
comparison, Hydro One again falls very near the mean of the comparison group.

Figure 8. Pole Program Costs Per Pole Touched Grouped by Company



Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

Figure 8. Pole Program Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

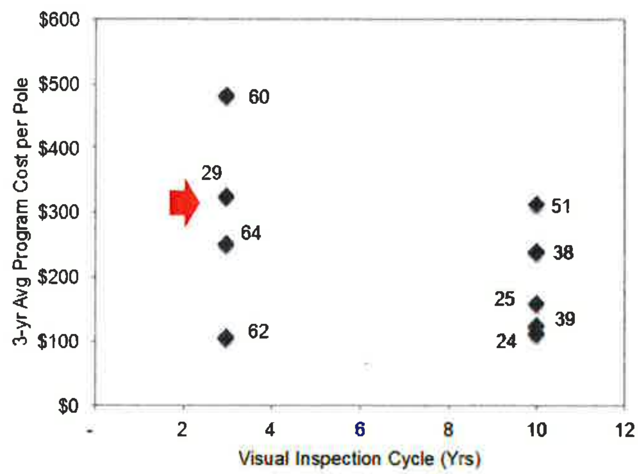
3.2 Pole Inspection Costs and Frequency

Inspection costs are a function of what is done during the inspection. For example, is it a visual inspection, sound and bore, or other more complex physical inspection. Hydro One performs visual and light physical inspections on a shorter interval than most other companies (three to six years compared to 10 for the panel). Hydro One is the only company that does not use bore, excavation or ultrasonic methods on a dedicated schedule (seven to 20 years).

3.2.1 Visual Inspection Cycle Time

Figure 12 shows the relative frequency of visual inspections and its impact on total pole replacement program costs. Where companies provided a range, the lower end of the range is represented in the figure. The frequency of inspections has only a modest impact on total program costs, since the majority of program costs are driven by pole replacements.

Figure 12. Visual Inspection Cycle Frequency



3.2.2 Physical Inspection Cycle Time

Though Hydro One doesn't have a comprehensive program for physical inspections, for those that are done, the cycle time is relatively short in comparison to the benchmark panel.

Figure 13. Physical Inspection Cycle Frequency

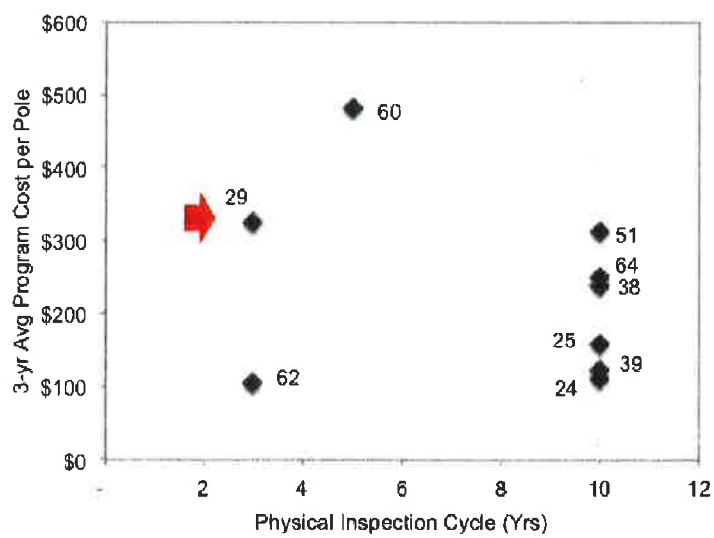
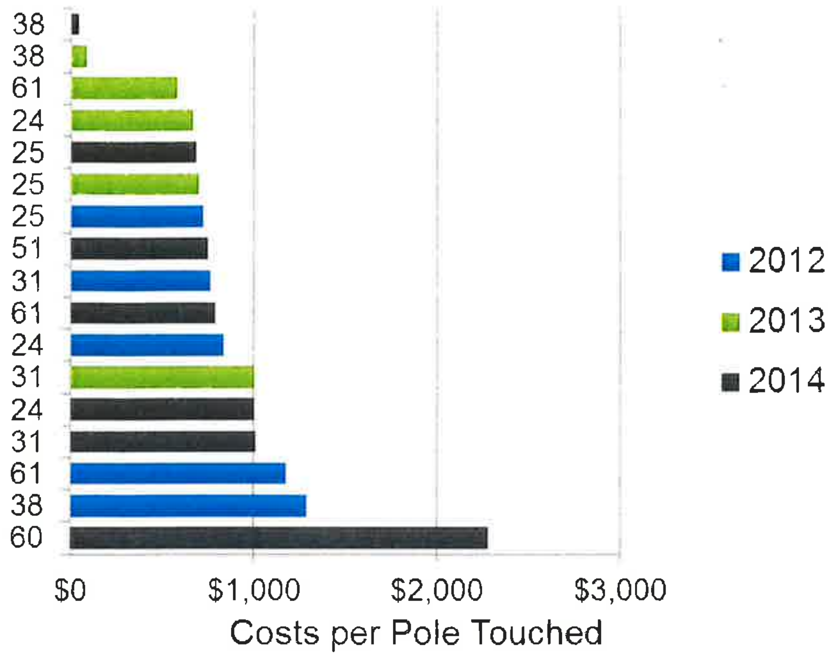


Figure 17. Pole Refurbishment Costs Ranked by Annual Spend



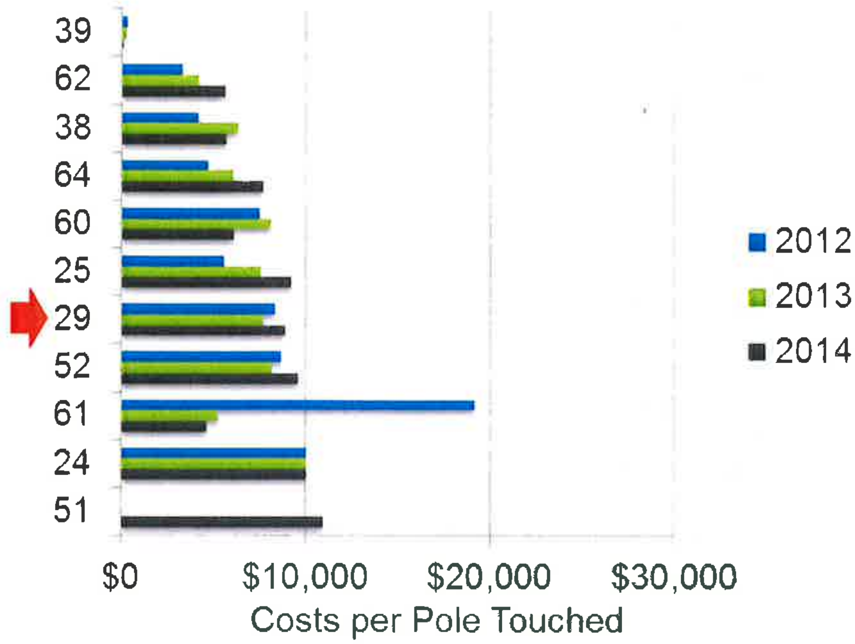
Note: In this comparison, pole touched means the total number of poles refurbished.

3.5 Pole Replacement Costs

As poles reach the end of their useful life, they must be replaced. All utilities have systematic programs for replacing those poles, with the goal of getting the longest useful life without allowing the poles to stay in service until their failure. Across the comparison group, the average cost to replace a pole is $7,105. For Hydro One, that cost is $8,266, or 16% higher than the mean.

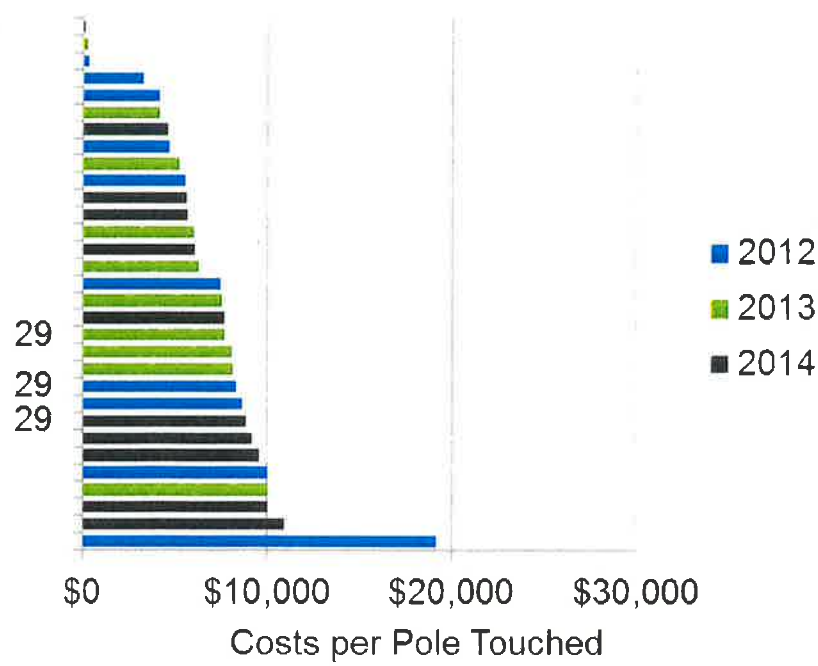
In the course of the study, a number of factors were investigated for their impact on the cost of replacing poles. This analysis revealed that these demographics had little impact on the overall results. Elements investigated include the planned life of the poles, the percent of poles installed off-road, the percent of poles installed in soft soil, the average travel time to get to poles, and average age of poles.

Figure 18. Pole Replacement Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles replaced.

Figure 19. Pole Replacement Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles replaced.

- for the submarine cable maintenance programs to meet challenges as a result of receding water levels in the Great Lakes and to replace deteriorated cable as a result of age; and
- to ensure compliance with Ontario Regulation 22/04. This regulation has established a standard for electrical distribution safety requirements for all licensed electricity distributors in Ontario as well as national technical standards for infrastructure design and construction (including utility plant) with an audit-based compliance system. This has resulted in increased hours and costs to work on existing plant in order to ensure adjacent existing structures meet this regulation.

The wood pole replacement and vegetation maintenance programs are two major areas affected by increased work volumes. However, Hydro One continues to refine its strategies to adapt and become more efficient in work execution.

Wood Pole Replacement: Hydro One owns approximately 1.6 million distribution poles across the province of Ontario. The Company's end of life pole replacement program is the largest funded capital work program within Provincial Lines, with an average of about 14,000 poles to be replaced each year over the next five years. With each pole replaced, system reliability directly improves as poles at risk of failure are replaced with new poles. To become more efficient and cost effective in executing the program, Hydro One strategically selects poles to be replaced based on priority and identified criteria and aligns targeted work with Forestry's annual trimming cycle. By doing so, the costs are significantly reduced as a forestry crew has already cleared the line and an unplanned return trip for forestry is not required. In addition, Hydro One has leveraged local knowledge to bundle poles that are nearing end of life or showing premature signs of decay on the same feeder. Utilizing dedicated project crews that focus on pole replacement has proven to be an efficient and cost-effective strategy, but is dependent on the Company's annual work program and emergent needs. An increased focus on

Pole Replacement - Historical Unit Costs

EB-2013-0416

	2012	2013	
Total Cost	$55,500,000	$73,900,000	D1-3-2, p.28
Units	7452	10700	A1-4-4, p.8
Cost/Unit	**$7,448**	**$6,907**	

EB-2017-0049

Cost/Unit	**$8,441**	**$7,824**	B1-1-1, DSP Section 1.4, p.3

4.3.2 Investment Plan

In order to better manage asset replacement activities, three programs of work are defined. Required funding for the test years 2015 to 2019, along with spending levels for the bridge and historical years are provided in Table 5 for each of these programs.

Table 5
Asset Replacement
($ Million)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Pole Replacements	53.6	54.7	55.5	73.9	82.5	88.7	95.1	105.0	115.2	125.8
Lines PCB Equipment Replacements	1.7	0.8	1.0	1.1	0.0	1.9	5.0	10.6	10.8	11.1
Line Projects	25.0	26.9	37.2	30.3	36.8	52.1	58.6	62.4	66.3	67.5
Total	**80.3**	**82.4**	**93.7**	**105.4**	**119.3**	**142.7**	**158.7**	**178.0**	**192.3**	**204.4**

Pole Replacements

The pole replacement program involves replacing poles that are at their end of life. In order to manage this population, an asset risk assessment is undertaken as outlined in Exhibit A, Tab 17, Schedule 7. Presently, approximately 11% of the pole population exceeds its expected service life, as documented in Exhibit D1, Tab 2, Schedule 1. Hydro One Distribution has been mitigating the risk of failure by selectively targeting replacement of end of life poles. Over the next several years, an increasing number of poles are expected to reach the end of their service life. A corresponding increase in the pole replacement rate is required to prevent the pole population from reaching an unmanageable state. An ageing pole population increases the likelihood of failures on the distribution system, as the structural integrity of a distribution line is largely dependent on its pole supports.

The following table provides details regarding the number of poles replaced due to end of life within the last five years:

Table 2:
Pole Replacement

	Actuals					Targets					
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Poles Replaced	**7,485**	**7,518**	**7,282**	**7,452**	**10,720**	**11.000**	**11,600**	**12,200**	**13,200**	**14,200**	**15,200**

The proposed metric for assessing Hydro One's performance with regards to pole replacements is:

- Poles replaced per year, targets for which are shown in Table 2.

Given the current age and condition of the poles, Hydro One expects to replace between 11,000 and 15,000 poles per year during the 5 year plan.

PCB Line Equipment (Sustaining Capital)

Table 3:
PCB Line Equipment

This is a new measure therefore only forecast targets of pole top transformers with PCB oil to be replaced are shown.

Year	2014	2015	2016	2017	2018	2019
Number of pole top Transformers with PCB oil to be replaced	**0**	**400**	**1,000**	**2,200**	**2,200**	**2,200**

Table 8 – Distribution OEB Scorecard

			Historical Results						Target	
RRF Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2018
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	72%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	86%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	81%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,640	8,733
		Vegetation Management - Gross Cyclical Cost per km $			New Program				9,441	9,382
		Station Refurbishments - Gross Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	461,000	454,000
		OM&A dollars per customer	456	451	498	551	453	455	449	455
		OM&A dollars per km of line	4,723	4,676	5,109	5,654	4,719	4,773	4,700	4,758
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,200	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	6,900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	145	145
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.1	9.0
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.4	3.4
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.8	2.8
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.7	1.7
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		135	197	228	136	143	143

*There were no station refurbishment units matching the criteria completed in 2012

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

SAIFI – Rural

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One SAIFI for the overall system. The SAIFI-Rural metric tracks the frequency of interruptions for the rural areas only. Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term which aligns with customer expectations.

$$= \frac{Total\ Rural\ Customer\ Interruptions}{Total\ Rural\ Customers\ Served}$$

Large Customer Interruption Frequency Large Distribution Accounts (LDAs)

This metric is newly proposed as part of this Application. During the customer engagement process, Large Distribution Accounts ("LDA") informed Hydro One that their top priority was interruption frequency as even a short outage could have major financial impacts to their operations. Hydro One will track this new measure to address this specific reliability concern. The goal is to improve performance compared to historical results. This metric tracks the total number of sustained interruptions to all LDA customers connected to Hydro One.

$$= \frac{Total\ Interruptions\ for\ Large\ Distribution\ Customers}{Total\ Large\ Distribution\ Customers\ Served}$$

2014 Asset Failure Analysis

hydro one

foster associates

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Schedule C

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

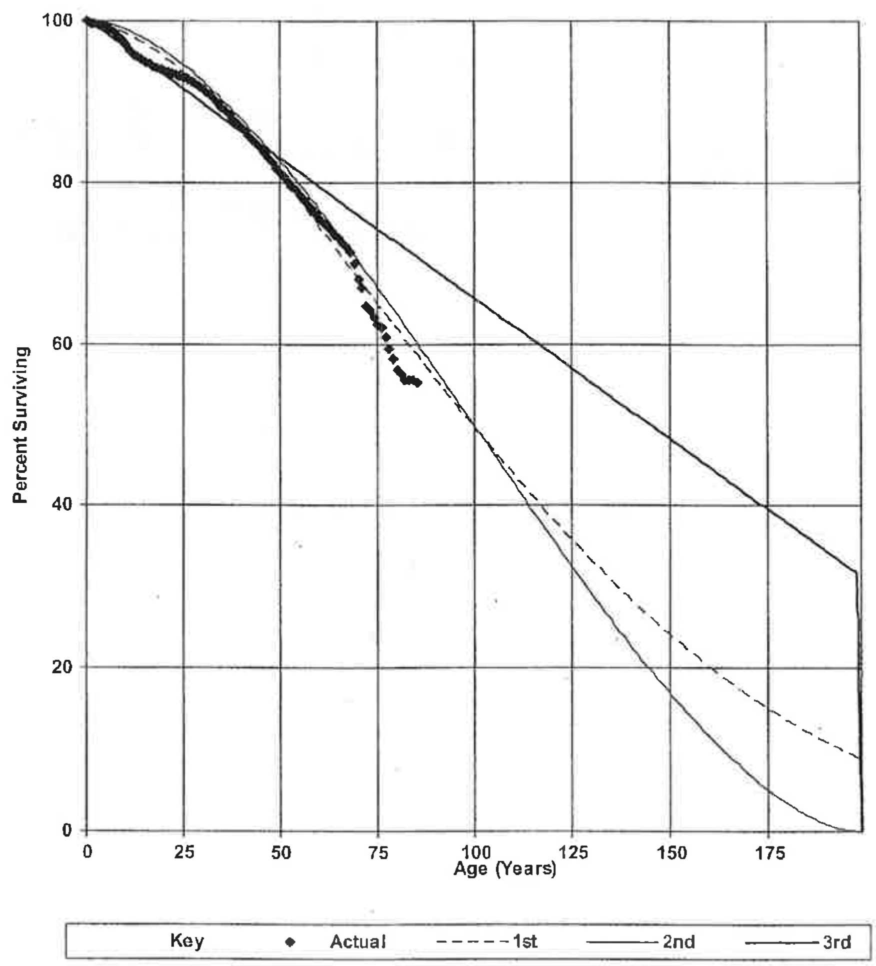
T-Cut: None

Placement Band: 1929-2013 Observation Band: 2005-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 106.7-L0.5 2nd: 99.1-S0 3rd: 144.6-SC



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APPENDIX C – SUPPLEMENTAL SURVEY RESULTS

Access Type – System Percentage

Access Type	km	Percentage
Back Lot	127	.1%
Inset from Road	6,099	6%
Roadside	87,870	87%
Cross Country	6,899	7%

***System KM Extrapolated**

Access km by Zone

Zone	Back Lot	Inset	Roadside	Cross Country
Zone A	31	1,265	27,479	487
Zone B	7	1,116	22,017	2,159
Zone C	52	2,682	23,244	3,144
Zone D	33	1,106	14,940	1,218

Tree Population

Zone	On-ROW	Off-ROW	Total	Per km
Zone A	1,163,884	1,093,974	2,257,858	77
Zone B	1,159739	1,786,023	2,945,762	116
Zone C	817,560	4,412,167	5,229,727	180
Zone D	401,559	2,319,491	2,721,091	157
Total	3,451,880	9,806,483	13,258,363	131

Note: 41% of spans surveyed had no trees present.

Brush Density - Extrapolated

Density	% of km	Hectares
None – no incompatible brush noted	53%	0
Ultra-Low - < 50 stems per span	28%	6,498
Very Low - < 50 – 250 stems per span	9%	26,823
Low - > 250 stems, easy to walk	6%	54,252
Medium – Clumpy, moderate effort to walk	<3%	67,606
Heavy – Dense, difficult to walk	<2%	63,729

Overhangs

Class	Spans Surveyed	Extrapolated
A (1-5) trees overhanging the ROW up to the conductor	543	47,000
B (6-10) trees overhanging the ROW up to the conductor	33	2,900
C (11-15) trees overhanging the ROW up to the conductor	9	800
F (1-5) trees overhanging the conductor	362	32,000
G (6-10) trees overhanging the conductor	44	3,900
H (11-15) trees overhanging the conductor	8	700
I (16-20) trees overhanging the conductor	2	170

Note: Less than 1% 44kV spans had overhangs present.

construction of stations, system protection and control, as well as engineering services as required. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Process,
- Project Management Process, and
- Project/Program Controls Process.

6.0 RELIABILITY

The reliability of the distribution system and its ability to deliver power to customers without interruption is measured using the following two OEB and industry metrics:

- System Average Interruption Duration Index ("SAIDI")
- System Average Interruption Frequency Index ("SAIFI")

SAIDI is a measure that indicates the amount of time without power that an average customer on Hydro One's distribution system experienced in a given year. SAIFI is a measure that indicates the number of times that an average customer on Hydro One's distribution system experienced an interruption in a given year.

Reliability performance is affected by the level of equipment maintenance and replacement programs, which ensure assets remain in good operating condition, and by the level of vegetation management, which ensures that outages caused by tree contacts are minimized. In addition, the time required to respond to a power interruption has a direct impact on restoration time and therefore impacts the SAIDI measure.