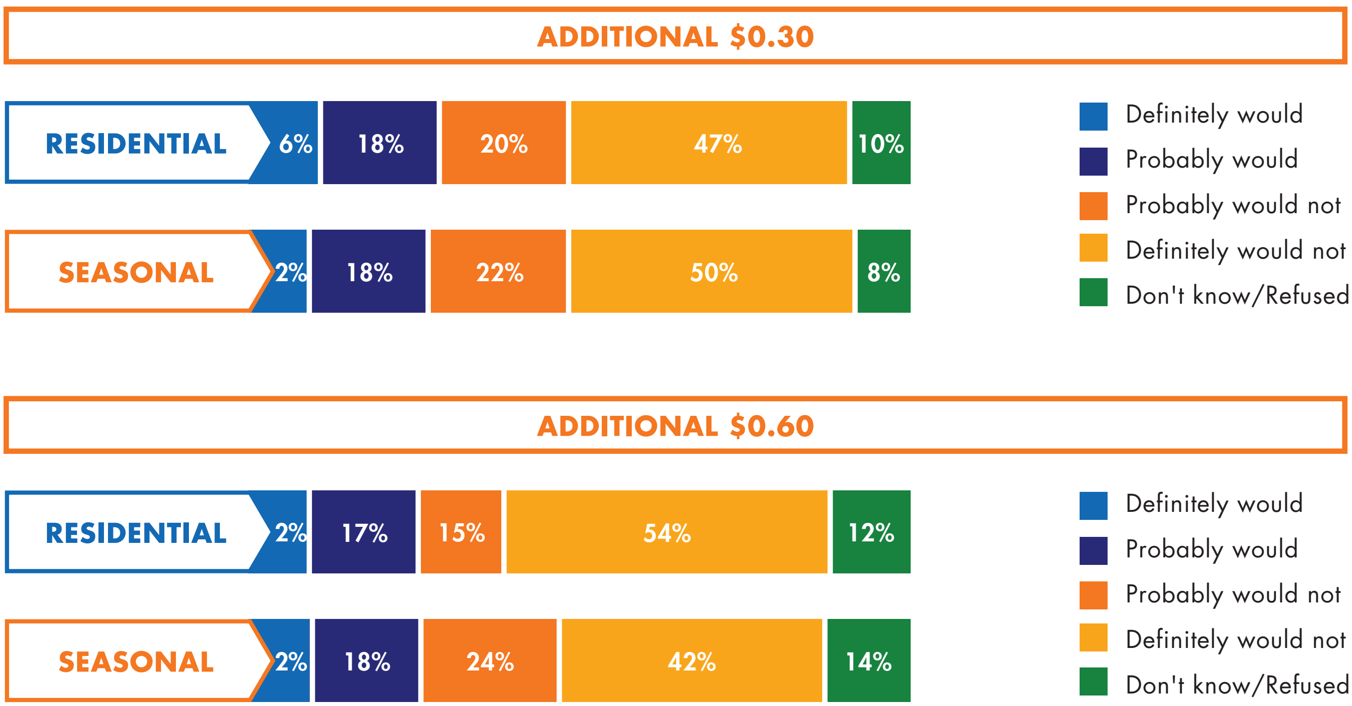
VECC Compendium
Panel 5: Asset Management Planning & Work Execution

Only 6% of Residential customers say they definitely would prefer to pay $2.30 more (or $11.50 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 18% say they probably would. Only 2% of Residential customers say they definitely would prefer to pay $2.60 more (or $13.00 by the fifth year) instead of the $2.00 (or the $10.00 by the fifth year) and 17% say they probably would.

TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS



Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30 / OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30 /$2.60] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50 / $13.00] higher than it is now? [READ LIST] Base: SPLIT SAMPLE (Residential n=200), Seasonal (n=50) the SAIFI-related interruption costs per outage in 2008, we used the "Momentary" cost per event estimate for each rate class. To determine the CAIDI-related interruption costs per outage in 2008, we took the "1 hour" cost per event for each rate class and then subtracted out the momentary costs. For all of the estimates we also translated the U.S. dollar figure into Canadian dollars using the 2008 Canadian Purchasing Price Parity (PPP) ratio. We then multiplied by the number of customers in that rate class and by the SAIFI to ascertain the SAIFI-related costs.

For the CAIDI-related costs, we multiplied by the number of customers in each rate class and by the CAIDI value. This gives us an estimate of the cost for each outage at the average duration. We then multiplied that value by the average number of outages (i.e., the SAIFI value) to give us the total CAIDI-related costs for each rate class.

The equation to determine the 2008 SAIFI-related customer interruption costs is:

$$SAIFI\ Costs_j = Momentary\ Costs_j * PPP * Customers_j * SAIFI$$

The equation to determine the 2008 CAIDI-related customer interruption costs is:

$$CAIDI\ Costs_j = \left(1\ Hour\ Costs_j - Momentary\ Costs_j\right) * PPP * Customers_j * CAIDI * SAIFI$$

The table below provides the SAIFI-related costs by rate class and the total estimated interruption costs related to SAIFI.

Table 13 SAIFI Costs

Rate Class	Momentary Interruption Costs (US$ 2008)	2008 PPP	Number of Hydro One Customers in 2008	2008 SAIFI (no MEDs, no power supply)	Total SAIFI Customer Interruption Costs (US$ 2008)
Residential	2.10	1.23	1,077,500	3.01	$8,377,379
Small C&I	293	1.23	109,722	3.01	$119,023,562
Medium & Large C&I	6,558	1.23	31	3.01	$752,670
Sum of All Classes					**$128,153,611**

The table below provides the CAIDI-related costs by rate class and the total estimated interruption costs related to CAIDI.

SS-01 Remote Disconnection / Reconnection Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	28.5
Primary Trigger:	System Efficiency		
Secondary Trigger:	Customer Service Requests		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. From time to time, there is a need to have power to these meters disconnected and/or reconnected as a result of customer non-payment and vacant premises.

Hydro One makes every effort to work proactively with customers to address billing issues and adheres closely to all steps mandated in the OEB Distribution System Code. Disconnection is only considered as a last resort; as customers rely on their power and understandably become upset if a decision is made to disconnect power. Hydro One makes every effort to take swift action in the reconnection of power for customers in order to reestablish important electrical services to their home or business.

Hydro One currently implements a manual disconnection and reconnection process, requiring at least two trips to the customer premises. These disconnection and reconnection activities cause between 10,000 and 21,000 on-site visits per year. The costs and associated risks of this manual process can be avoided with the utilization of meters that have the functionality to execute remote disconnection and reconnection.

Alternative 1: Continue Manual Disconnections/Reconnections

Continue to manually disconnect and reconnect customer meters when required in accordance with Section 4.2 of the OEB Distribution System Code. This alternative is rejected as it will not result in improving the customer experience or achieving operational efficiencies.

Alternative 2: Remote Disconnections/Reconnections *(Recommended)*

Install new meters with remote disconnection and reconnection functionality at customer sites where non-payment and/or vacant premises situations exist. This alternative is recommended as it will reduce the number of visits to customer premises resulting in operational efficiencies, and improve customer experience by providing a faster response time for disconnection and reconnection requests. Active and timely actions to address customers in arrears also assists customers in staying current with their invoices and reducing bad debt expenditure.

Investment Description:

This investment addresses the replacement of existing meters at customer premises with new meters capable of remote disconnection and reconnection functionality. Meter replacements will be identified for replacement when disconnection required based on assessment of customer accounts in arrears due to non-payment and/or customer premises with noted vacancy. These replacements are to be rolled out in stages as work orders are authorized and appropriately approved for action of disconnection. The table below is an annual forecast of meter replacements.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Meter Replacements	11,875	11,500	11,125	10,750	10,375

Once the new meters are installed, the actual execution of the reconnection (or disconnection) is accomplished within a few minutes after the customer request has been authorized and appropriately approved for action thereby reducing lost revenue for unbilled power, and providing improved customer service through faster response time.

Risk Mitigation:

The risks to completion of this investment as planned are the availability of the vendor to manufacture and deliver the meters in a timely manner, and the accessibility of the meters required to be replaced. These risks are mitigated by providing procurement forecasts upfront to the vendor, maintaining ongoing discussions with vendor regarding future product supply, and managing coordination with resources required to gain access.

OEB Staff Interrogatory # 160

Issue:

Issue 26: Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?

Reference:

B1-01-01 Section 3.8 Page: 2658

(5.4.5.2) Attachments: Material Investments, ISD: SS-01 Remote Disconnection/Reconnection Program

Interrogatory:

"Alternative 2: Remote Disconnections/Reconnections (Recommended)

Install new meters with remote disconnection and reconnection functionality at customer sites where non-payment and/or vacant premises situations exist. This alternative is recommended as it will reduce the number of visits to customer premises resulting in operational efficiencies, and improve customer experience by providing a faster response time for disconnection and reconnection requests. Active and timely actions to address customers in arrears also assists customers in staying current with their invoices and reducing bad debt expenditure."

a) What is the total cost of installing this remote controlled meter compared to the labour hours of manual disconnect and reconnect?

b) Does the cost of installing the remote controlled meter include the cost of infrastructure needed to operate the remote control, such as, control station, telemetry, and operator? If not, why not?

Response:

a) The total cost of installing a remote disconnect / reconnect meter is approximately $500. The labour cost to manually disconnect / reconnect a meter installation is approximately is $120 each, or $240 total, not including the cost of the meter/installation.

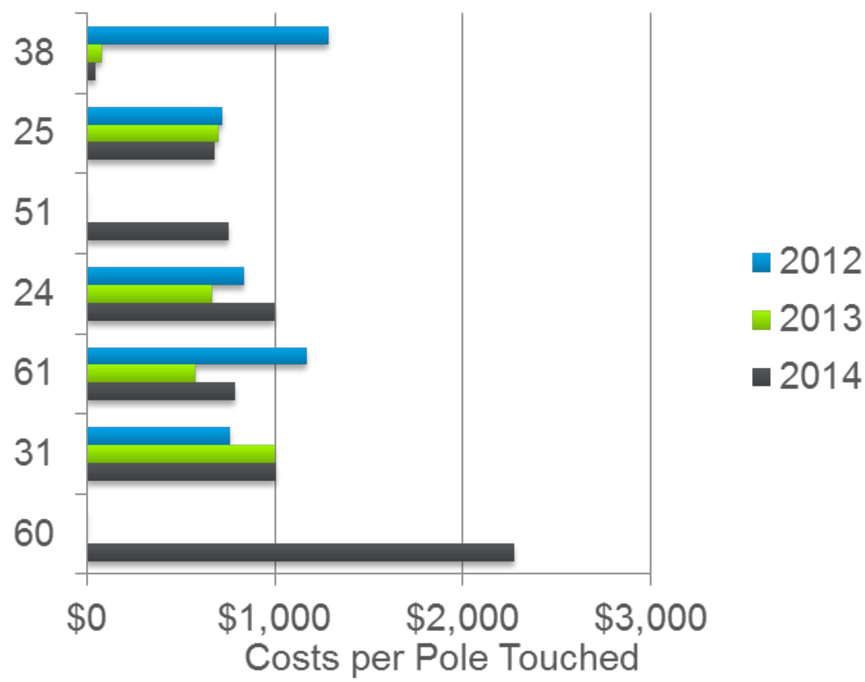
b) There are no incremental costs associated with operating the remotely controlled meters. Hydro One is leveraging existing infrastructure and processes to remotely operate the meter.

3.4 Pole Refurbishment Costs

Most North American utilities (13 of 17 in the study) have a formal distribution pole refurbishment practice in place to deal with poles that fail prematurely. Hydro One currently does not have such a refurbishment program, electing to replace poles that fail, rather than refurbish them. The fact that Hydro One has experienced a long life for its poles is one indicator of the reasonableness of this approach. At the same time, organizations with refurbishment practices in place are able to demonstrate that their lifecycle costs have improved due to the refurbishment practice.

Figure 16 and Figure 17 show the unit costs for pole refurbishment for those companies who track and could report those costs. The mean cost to refurbish a pole is $947.

Figure 16. Pole Refurbishment Costs Grouped by Company



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

3.3 Replacement Rates and Pole Age

Hydro One has historically replaced its poles at a slower rate than other utilities. This fits with its planned longer life of the poles than other utilities in the comparison group. The net result is that the average age of Hydro One's wood poles is the oldest in the panel, at 37 years.

Figure 14. Age Profile of Wood Poles

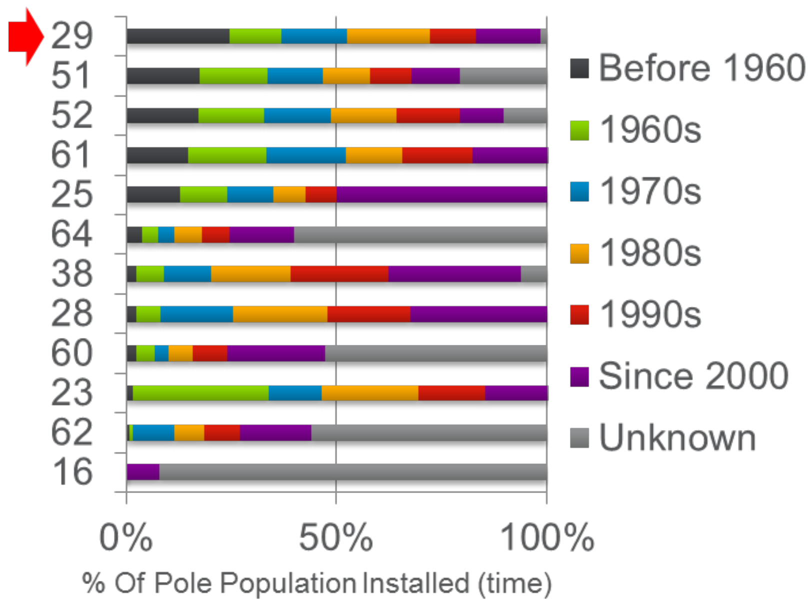
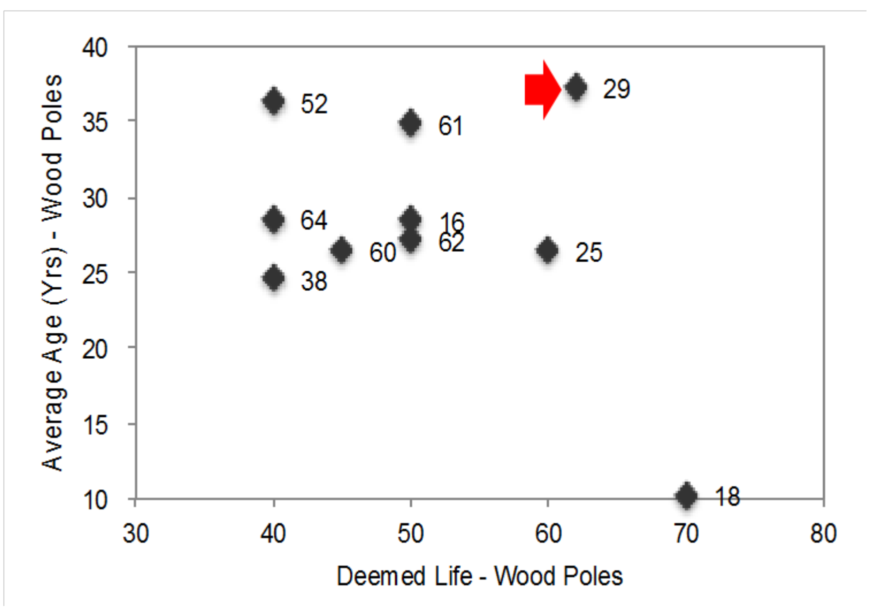


Figure 15. Average Age versus Planned End of Life



Hydro One Networks – Business Case Summary (Short Form for Qualified Projects)

hydro one

Investment Name: WPF Owen Sound TS M25 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81686	Claim #: 51002914
AR: 25210	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $840k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): $840k

Investment Summary:

Owen Sound TS M25 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 1.61 million. The feeder has 117.5 km of right of way and supplies 8455 customers.

This investment will install 7 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker and up to three feeder tie points. One of the new switch locations is a tie point to an adjacent feeder (Hanover TS M4) and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

The cost for the project is based on a unit cost per switch ($120k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

Status Quo: The Do Nothing alternative would have no expected improvement in reliability on this feeder.

Benefits

Adding 7 remote operable switches to Owen Sound TS M25 is expected to provide a 14% reliability improvement which translates to an estimated average of 229k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	840		840
OM&A and Removals			
Gross Investment Cost	840		840
Recoverable			
Net Investment Cost	840		840

Project Risk Assessment

This project was not specifically included in the approved 2018-2023 business plan however funds will be redirected from the Worst Performing Feeder Program (AR24301) that has $7M in 2018. Additional funding required above the approved budget of $7M will be redirected from within the Distribution Capital Driver envelope.

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 30th/2018
Approved by: Peter Faltaous	Manager, Distribution Investment Planning	Signature:	Date: Jan 30, 2018

Scientific Research & Experimental Development Tax Credits (SR&ED):

Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

Author: Jerry Vo
Date: January 29, 2018

Hydro One Networks – Business Case Summary (Short Form for Qualified Projects)

Investment Name: WPF Snow Road DS F2 Communicating FCIs		
AIP #: AIP005826	Subject ID: 81668	Claim #: 51002838
AR:25179	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $39k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 39

Investment Summary:

Snow Road DS F2 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.1 million. The feeder has 211km of right of way and supplies 844 customers. The average outage duration was 4.1 hours with over 2 hours of that time spent searching for the location of the outage.

This investment will install 13 Communicating Fault Current Indicators (CFCI) at 6 strategic locations to give Operations real time information when the fault occurs. This information will improve reliability by using the information provided by the CFCIs to reduce the area to be searched in order to locate the fault.

The cost for the project is based on a unit cost of $3k per CFCI. The unit costs were developed based on known material costs and estimated labour costs agreed upon with the service provider.

Other Alternatives Considered

Status Quo: The Do Nothing alternative would lead to similar search times for future outages and no expected improvement in reliability on this feeder.

Benefits

Adding 13 CFCI devices to Snow Road DS F2 is expected to provide an 18.6% reliability improvement which translates to 383k CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	39		39
OM&A and removals			
Gross Investment Cost	39		39
Recoverable			
Net Investment Cost	39		39

Project Risk Assessment

This project was not specifically included in the approved 2018-2023 business plan however funds will be redirected from the Worst Performing Feeder Program (AR24301) that has $7M in 2018.

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 11th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 17'18

Scientific Research & Experimental Development Tax Credits (SR&ED):

Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

Author: Nathan Cox
Date: January 5, 2018

29-SEC-52

Please complete the shaded area

		EB-2013-0416 Pre-Filed Evidence [# Asset/Project]					EB-2017-0049 [# Asset/Project]							
Asset/Project Type	**ISD**	**2015F**	**2016F**	**2017F**	**2018F**	**2019F**	**2015A**	**2016A**	**2017A**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
Transformer Replacements	S-01	6	6	6	6	6	8	3	5	Note 1	Note 1	Note 1	Note 1	Note 1
Transformer Spares	S-01	26	27	26	31	32	40	7	5	4	5	6	6	6
MUS Trailer Replacements	S-02	2	3	1	2	0	0	0	0	2	1	2	1	0
MUS Transformer Replacements	S-02	0	0	0	0	5	0	0	0	2	1	2	1	0
MUS Purchases	S-02	1	1	1	1	0	0	0	1	0	0	0	1	2
Stations targeted for Spill Containment	S-03	2	2	2	2	2	1	1	0	1	1	1	1	1
Feeders identified for Recloser Upgrades	S-05	17	22	18	15	12	4	13	10	13	13	13	12	12
Station Refurbishments	S-07	36	38	38	41	41	29	11	9	8	15	15	17	18
Pole Replacements	S-10	11,600	12,200	13,200	14,200	15,200	11,837	12,355	9,642	9,600	14,300	16,000	16,123	16,128
PCB Lines Equipment Replacements	S-11	400	1,000	2,200	2,200	2,200	34	347	0	2,152	2,152	2,152	3,228	3,228
Large Sustainment Initiatives	S-12	11	11	11	7	11	12	6	2	7	13	13	13	12
Development Capital - New Connections	D-01	15530	15570	15850	16010	16170	13,139	15,657	17,273	14,724	14,862	15,005	15,148	15,291
Development Capital - Service Upgrades	D-01	4554	4604	4654	4704	4744	3,960	4,180	3,935	4,473	4,515	4,558	4,601	4,645
Development Capital - Service Cancellations	D-01	6230	6300	6360	6420	6490	5,319	7,970	4,804	5,562	5,614	5,668	5,722	5,776
Upgrades Driven by Load Growth	D-02	9	14	13	12	12	4	8	15	4	20	11	8	5
Asset Life Cycle Optimization and Operational Efficiency	D-05	5	3	5	3	3	1	0	5	4	9	8	8	8
Reliability Improvements	D-06	2	2	1	1	2	0	1	0	0	1	1	1	2
Distribution Station Security Upgrades	C-05	3	3	3	3	TBD	0	3	0	3	3	3	3	3

Source: D2-2-3

Note 1 *:In EB-2013-0416, S-01 was a Transformer Spares and Replacement Program. As documented in EB-2017-0049 Exhibit B1, Tab 1, Schedule 1, Section 3.8, SR-03 is now only for the purchase of station spare transformers, and no longer supports the purchase of transformers for planned replacements.*

Vulnerable Energy Consumers Coalition Interrogatory # 18

Issue:

Issue 18: Are the metrics in the proposed additional scorecard measures appropriate and do they adequately reflect appropriate outcomes?

Reference:

B1-01-01 Section 1.4

Interrogatory:

a) Defective equipment is the 2nd largest contributor to outage duration. How does Hydro One's scorecard metrics demonstrate to customers the value added of its capital program in reducing outages due to defective equipment?

b) Scheduled outages are the 3rd largest contributor to reliability. What scorecard metric demonstrates Hydro One's ability to minimize schedule outages and their duration?

Response:

a) Hydro One has scorecard metrics related to reliability. Our goal is to achieve a 20% improvement in reducing defective equipment outages over five year period through system renewal investments, distribution automation and worst performing feeder improvements documented in Exhibit B1, Tab 1, Schedule 1 and Exhibit I-23-Staff-85, part a).

b) Hydro One has scorecard metrics related to reliability. Our goal is to achieve a 20% Improvement in Planned Outage impact on reliability over five year period.

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

OEB Staff Interrogatory # 70

Issue:

Issue 20: Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?

Reference:

B1-01-01 Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.2.1 Reliability Results, Table 14 - SAIFI by Outage Cause, Page 1940 of 2930.

Table 14 - SAIFI by Outage Cause

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

Interrogatory:

a) For the Outage Causes listed in Table 14, please indicate which of these causes are within the control of Hydro One, and which are outside of Hydro One's control.

b) Please identify the projects and programs in the planned Capital Expenditure program and OM&A that are intended to address the negative trends in Tree Contacts and Foreign Interference outage measures.

c) Defective Equipment outages appear to be trending downwards. Does this improving performance indicate that there is an opportunity to reduce (or hold steady) sustaining capital expenditures?

Response:

a) **Adverse Environment** - Hydro One has little to no control over Adverse Environment outage causes.

Defective Equipment - Hydro One has some, but not absolute, control over Defective Equipment outage causes.

Foreign Interference - Hydro One has some, but not absolute, control over Foreign Interference outage causes. Depending on the type of interference, Hydro One may not have absolute control over outages caused by external factors such as Motor Vehicle Accidents (MVAs).

Human Element - Hydro One has some, but not absolute, control over Human Element. Outage causes such as Public and Third Party Equipment outage causes may not be in Hydro One's control.

Loss of Supply - Hydro One has some, but not absolute, control over Loss of Supply (LOS). Some factors that can cause LOS outage may include, but not limited to, FM and external interference that caused transmission outage that are out of Hydro One's control

Scheduled - Hydro One has control over Scheduled outages causes.

Tree Contacts - Hydro One has some, but not absolute, control over Tree Contacts outage causes depending upon available resources and if adverse environment conditions are present.

Unknown/Other - Hydro One does not have control over Unknown/Other outage causes.

b) The numbers in the above table do not represent a significant negative trend in the frequency of Tree Contacts and Foreign Interference caused outages. The projects and programs that impact the frequency of Tree Contact outages and Foreign Interference outages are as follows:

Tree Contacts - Capital expenditures that address the frequency of tree contact outages are those that reduce the exposure of lines to vegetation via relocation from heavily forested off road locations to roadside allowance, or that improve the ability to sectionalize the system. Projects of this type are identified in ISDs SR-12 (Distribution Lines Sustainment Initiatives) and SS-06 (Worst Performing Feeders Program) respectively. The primary OM&A program that addresses the frequency of tree contacts is the Vegetation Management program.

Foreign Interference - Expenditures that address the frequency of foreign interference outages are primarily those that reduce exposure of the system to wildlife. These include the capital Nest Platform component of the component replacement program and installing Animal cover-up at stations with a high number of animal contacts through the Stations OM&A Demand and Planned Corrective Maintenance program.

c) The SAIFI impact of outages classified as "Defective Equipment" is not significantly trending downwards. The relatively flat contribution to SAIFI of equipment outages does not indicate an opportunity to reduce sustaining capital expenditures.

OEB Staff Interrogatory # 69

Issue:

Issue 20: Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?

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; and Section 1.4.2.1 Reliability Results, Table 13 - SAIDI by Outage Cause, Page 1939 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

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					

Interrogatory:

a) Table 8 above shows that 2013 had the best SAIDI/SAIFI performance relative to the other years on Table 8. However, Table 13 shows that 2013 was the worst year of the five shown. Please reconcile this apparent contradiction.

b) Does "Defective Equipment" as shown in Table 13 solely account for outages caused by spontaneous/autonomous equipment failure, or does it also include outages where an external trigger initiated the equipment failure, e.g.: ice, snow and wind loads, lightning strikes? If the latter case, is it possible to report separately on these two categories and provide a breakdown of causes?

Response:

a) This perceived contradiction between Table 8 and Table 13 is caused by the difference in criteria used. The SAIDI/SAIFI numbers on Table 8 excludes LOS and FM while Table 13 includes LOS and FM. Due to a large FM event in 2013, including/excluding FM will impact the resulting SAIDI/SAIFI performance relative to other years.

b) The “Defective Equipment” as shown in Table 13 accounts for outages caused by spontaneous/autonomous equipment failure as well as outages where an external trigger initiated the equipment failure. The data set does not have the level of granularity to report separately on these two categories to provide a breakdown of causes.

Response:

a) The correct interpretation of Figure 4 is that, when Loss of Supply and Force Majeure outages are excluded, SAIFI, which is the average number of interruptions per customer served per year, stays relatively constant. SAIFI is a ratio of the number of customers impacted by outages in a given year to the customers served. Therefore, SAIFI is not representative of the frequency of the number of outages alone, and it is incorrect to conclude that the frequency of outages is not increasing simply because SAIFI is not increasing.

$$\boldsymbol{SAIFI} = \frac{Total\ Customer\ Interruptions}{Total\ Customer\ Served}$$

b) An increased level of weather and vegetation related events, requiring restoration efforts from Forestry and Lines, resulting in longer restoration times. The majority of the longer duration outages are in remote areas which are difficult to access.

Hydro One is committed to improving our restoration times and the Company completed a pilot trial of remote sectionalization in the Owen Sound area, which improved reliability in a measurable way. In recent outages on upgraded feeders the combination of the Distribution Management System and its fault location capability along with remote sectionalization reduced outage times by about 50%. The Company is looking to expand that approach, by installing remote sectionalization in areas where it would prove to be a cost effective reliability improvement investment, and leveraging smart meters to locate outages more accurately, by intelligently pinging meters and examining the meter's real-time power outage notifications.

Witness: JESUS Bruno