EB-2017-0049

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2018 to December 31, 2022.

COMPENDIUM OF THE SCHOOL ENERGY COALITION

(Asset Management Planning & Work Execution Panel)

Shepherd Rubenstein P.C.
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Mark Rubenstein
Jay Shepherd
Tel: 416-483-3300
Fax: 416-483-3305

Counsel for the School Energy Coalition

School Energy Coalition Interrogatory # 38

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 3.2, Tables 54-55

Interrogatory:

Please provide revised versions of Tables 54 and 55 by adding a column under the 2017 heading showing 2017 actuals.

Response:

Exhibit I-24-SEC-038 Attachment 1 DSP_Table_54-57.xlsx contains corrected versions of Tables 54 to 57. The original filing inaccurately categorized a handful of System Capacity Reinforcement Projects between the OEB categories of General Plant and System Service. The tables have also been updated to reflect the changes described in Exhibit Q and the updated OM&A forecast reflected in Exhibit I-38-SEC-70.

Witness: BRADLEY Darlene

Category	Historical and Bridge (previous plan and actual)										
	2013*	2014*	2015			2016			2017 Bridge		
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$M	$M	$M	$M	%	$M	$M	%	$M	$M	%
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	181.9	3.3
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	214.3	(24.8)
System Service	80.4	71.0	95.4	69.8	(26.9)	89.7	78.9	(12.0)	86.0	80.1	(6.8)
General Plant	131.4	114.4	119.5	112.0	(6.3)	117.0	144.3	23.4	114.3	101.6	(11.1)
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	577.9	(12.6)
System OM&A**	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	558.7	(5.8)

** 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.*

*** System OM&A values include all Operations, Maintenance and Administration expenses.*

Category	SDOC	SDOC Breakdown	Historical and Bridge (previous plan and actual $M)							
			2013	2014	2015		2016		2017	
			Actual	Actual	Plan	Actual	Plan	Actual	Plan	Actual
System Access	Sustaining Capital	Lines	26.2	26.3	26.7	25.5	27.3	23.3	27.8	15.6
		Meters	11.2	35.8	14.6	34.7	20.5	42.3	23.8	28.1
	Development Capital	Connections, Upgrades	92.7	111.3	108.9	113.9	112.1	108.2	115.8	128.9
		Generation Connections	25.5	25.4	33.1	13.9	22.7	8.8	8.7	9.6
		Wholesale Revenue Meters	3.9	0.4	0.0	0.1	0.0	0.1	0.0	-0.2
System Access Total			**159.5**	**199.4**	**183.3**	**188.1**	**182.6**	**182.7**	**176.1**	**181.9**
System Renewal	Sustaining Capital	Lines	201.2	190.7	189.0	216.0	202.1	212.5	221.3	169.2
		Meters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Stations	56.5	69.4	61.7	87.1	63.3	66.9	63.7	35.5
	Development Capital	System Capability Reinforcement	8.0	2.6	0.0	5.3	0.0	8.8	0.0	9.5
System Renewal Total			**265.7**	**262.7**	**250.7**	**308.4**	**265.4**	**288.3**	**285.0**	**214.3**
System Service	Sustaining Capital	Lines	7.0	4.6	11.9	9.2	17.4	15.2	18.3	16.1
		Meters	21.1	16.0	2.0	1.8	0.0	0.0	0.0	1.3
		Stations	0.0	0.0	2.2	0.0	4.5	0.0	4.8	0.0
	Development Capital	System Capability Reinforcement	45.9	41.9	56.7	52.8	57.9	46.5	59.0	43.8
	Operations Capital	Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Smart Grid Pilot	6.4	8.5	22.5	6.0	9.9	17.2	3.9	18.9
System Service Total			**80.4**	**71.0**	**95.4**	**69.8**	**89.7**	**78.9**	**86.0**	**80.1**
General Plant	Development Capital	System Capability Reinforcement	16.1	14.5	24.7	2.1	13.6	1.4	24.1	-0.6
	Operations Capital	Operations	3.6	4.1	9.4	7.0	18.8	10.3	7.0	11.0
	Capital Common Corporate Costs and Other Costs	Cornerstone	47.6	7.3	0.0	1.2	0.0	0.3	0.0	0.0
		Facilities & Real Estate	10.1	20.3	19.0	18.5	15.3	25.1	15.4	14.7
		Information Technology	13.4	17.7	22.6	30.9	20.1	58.8	22.9	44.2
		Other	-2.9	1.5	0.0	0.1	0.0	0.8	0.0	0.5
		Transport and Work Equipment	43.5	49.1	43.8	52.1	49.1	47.6	44.8	31.8
General Plant Total			**131.4**	**114.4**	**119.5**	**112.0**	**117.0**	**144.3**	**114.3**	**101.6**
Grand Total			**637.0**	**647.5**	**648.9**	**678.3**	**654.7**	**694.2**	**661.4**	**577.9**

Category	Forecast (Planned $M)				
	2018	2019	2020	2021	2022
System Access	154.6	157.6	160.9	165.9	170.0
System Renewal	248.6	318.7	336.7	362.5	451.1
System Service	81.6	91.6	85.6	78.8	69.5
General Plant	143.3	168.5	116.2	103.7	105.9
Total	628.1	736.4	699.3	711.0	796.5
System OM&A*	576.7	581.1	585.4	600.6	605.1

** System OM&A values include all Operations, Maintenance and Administration expenses.*

Updated 2018 OM&A for Fair Hydro Plan by ($2.9M), future years based on Custom IR formula.

2021 and 2022 include Acquired utilities.

Category	SDOC	SDOC Breakdown	Forecast (Planned $M)				
			2018	2019	2020	2021	2022
System Access	Sustaining Capital	Lines	21.7	22.0	22.2	22.6	22.8
		Meters	18.9	19.4	19.7	20.5	21.1
	Development Capital	Connections, Upgrades	109.9	112.9	115.7	120.0	123.2
		Generation Connections	4.1	3.4	3.3	2.9	3.0
		Wholesale Revenue Meters	0.0	0.0	0.0	0.0	0.0
System Access Total			**154.6**	**157.6**	**160.9**	**165.9**	**170.0**
System Renewal	Sustaining Capital	Lines	199.8	245.7	263.1	279.2	283.7
		Meters	0.0	0.0	0.0	1.4	78.5
		Stations	28.3	45.9	51.1	52.9	54.0
	Development Capital	System Capability Reinforcement	20.5	27.1	22.4	29.0	34.9
System Renewal Total			**248.6**	**318.7**	**336.7**	**362.5**	**451.1**
System Service	Sustaining Capital	Lines	7.1	7.3	7.4	7.7	7.8
		Meters	6.0	6.0	5.9	5.8	5.8
		Stations	0.0	0.0	0.0	0.0	0.0
	Development Capital	System Capability Reinforcement	63.4	78.4	72.3	64.6	55.9
	Operations Capital	Operations	0.0	0.0	0.0	0.7	0.0
		Smart Grid Pilot	5.0	0.0	0.0	0.0	0.0
System Service Total			**81.6**	**91.6**	**85.6**	**78.8**	**69.5**
	Development Capital	System Capability Reinforcement	8.4	3.1	0.0	0.0	0.0
	Operations Capital	Operations	26.9	42.7	5.8	5.4	8.2
	Capital Common Corporate Costs and Other Costs	Cornerstone	0.0	0.0	0.0	0.0	0.0
		Facilities & Real Estate	34.6	44.1	37.9	36.2	33.0
		Information Technology	44.8	47.8	43.5	34.7	37.5
		Other	-3.5	-4.3	-6.5	-8.3	-8.7
		Transport and Work, and Service Equipment	32.1	35.1	35.4	35.6	35.8
General Plant Total			**143.3**	**168.5**	**116.2**	**103.7**	**105.9**
Grand Total			**628.1**	**736.4**	**699.3**	**711.0**	**796.5**

Association of Major Power Consumers in Ontario Interrogatory # 52

Issue:

Issue 33: Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

Reference:

D1-01-02 In Service Additions

Interrogatory:

a) Please update Tables 1 and 2.

Response:

a) Table 1 below has been updated with 2017 Actuals.

Table 1: In-Service Capital Additions 2013-2017 ($M)
OEB Approved and Actual/Forecast (updated for 2017 Actuals)

	Historic								Bridge		
	2013	2014	2015			2016			2017		
	Actual		OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance (Act)
Sustaining	296.6	324.8	294.2	420.2	126.0	311.9	371.1	59.2	335.7	322.8	-13.0
Development	194.1	187.6	218.9	216.9	-2.0	200.8	168.3	-32.5	211.2	216.5	5.3
Operations	1.4	5.0	11.1	7.0	-4.1	8.1	-0.3	-8.4	16.4	14.0	-2.4
Customer Service	13.9	1.4	46.0	16.6	-29.4	20.6	6.5	-14.1	27.7	10.9	-16.7
Common & Other	223.4	96.6	86.5	100.5	14.1	80.4	109.3	28.9	105.0	116.8	11.8
Total	**729.3**	**615.3**	**656.7**	**761.3**	**104.6**	**621.8**	**654.9**	**33.2**	**696.0**	**681.0**	**-15.0**

Please refer to Exhibit Q, Tab 1, Schedule 1 Table 6 (filed 2017-12-21) for an updated In-Service Capital Addition forecast.

Witness: BOWNESS Brad

Table 6: In-Service Capital Additions 2018-2022 ($M)

	Forecast				
	2018	**2019**	**2020**	**2021**	**2022**
Sustaining	292.5	335.6	361.5	384.2	427.3
Development	194.4	268.9	218.9	219.2	221.0
Operations	12.4	6.6	68.6	0.6	19.2
Customer Service	30.2	0.2	0.2	0.2	0.2
Common & Other	105.6	143.9	99.3	100.3	116.7
Total	**635.1**	**755.2**	**748.5**	**704.6**	**784.4**

Exhibit Reference: D1-1-2

Table 7: Distribution Rate Base ($ Millions)

Description	Test				
	2018	**2019**	**2020**	**2021**	**2022**
Mid-Year Gross Plant	11,905.1	12,484.4	13,143.1	13,988.0	14,666.8
Mid-Year Accumulated Depreciation	(4,564.1)	(4,798.7)	(5,067.4)	(5,412.3)	(5,741.1)
Mid-Year Net Plant	**7,341.1**	**7,685.7**	**8,075.7**	**8,575.8**	**8,925.7**
Cash Working Capital	321.2	335.7	348.3	378.5	395.3
Materials and Supplies Inventory	4.1	5.5	6.5	5.9	5.5
Distribution Rate Base	**7,666.4**	**8,026.9**	**8,430.5**	**8,960.1**	**9,326.5**

Exhibit Reference: D1-1-1

1.3 COST OF CAPITAL

As indicated in Exhibit D1, Tab 2, Exhibit 1, Hydro One anticipated updating the revenue requirement when the Board released its 2018 cost of capital parameters, reflecting: (a) the OEB-approved 2018 return on equity and short-term debt rates; and (b) a long-term debt rate based on Hydro One's actual 2017 debt issuances to-date and the September 2017 Consensus Forecast. Updates for these changes are summarized in Table 8 below, and applied to the updated Distribution Rate Base amounts described in Table 7 above.

1

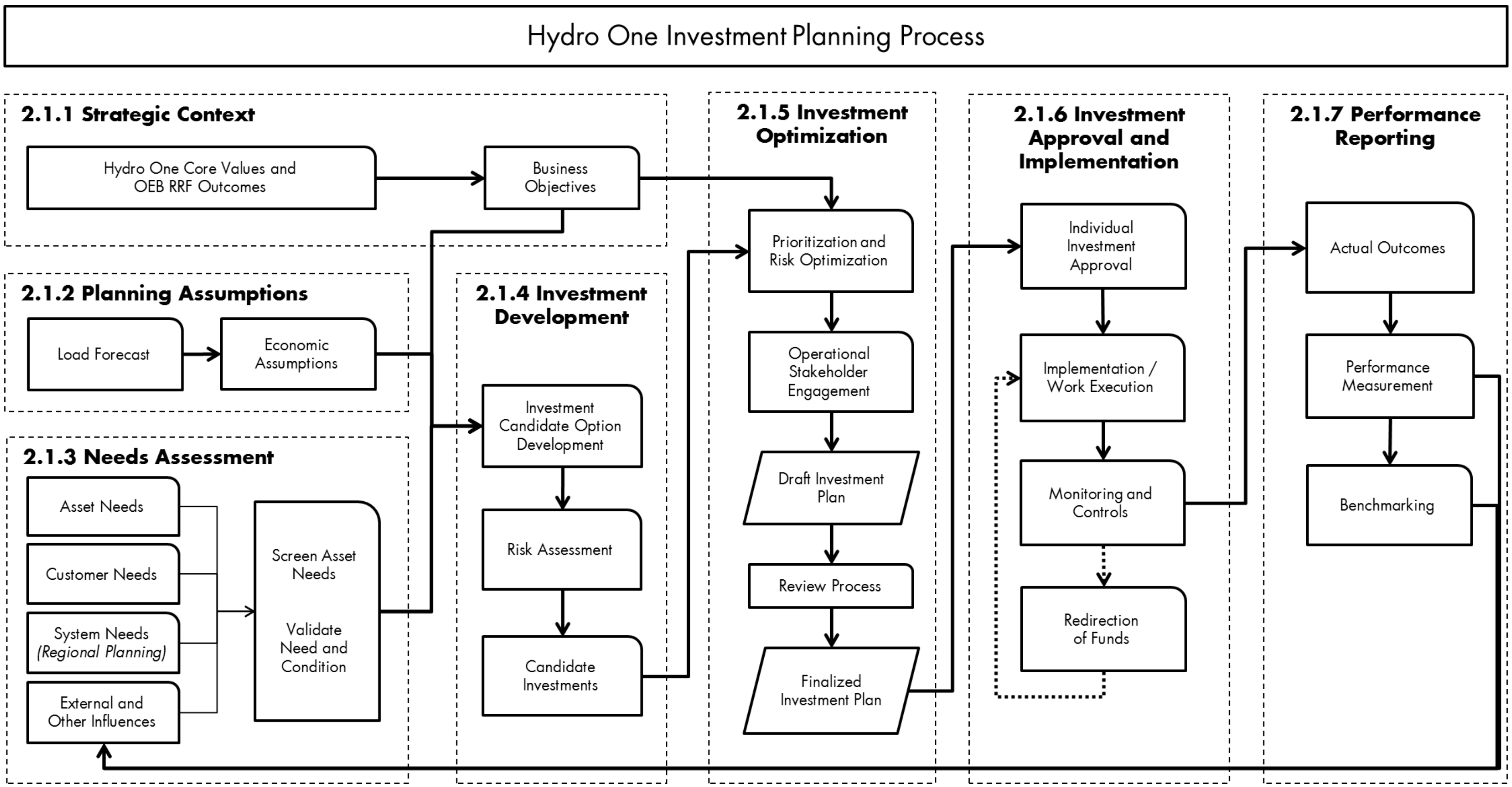


Figure 9 - Hydro One's Investment Planning Process

Witness: Darlene Bradley

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.

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 Category		# asset units				# asset units				# asset units				# asset units			
		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

Asset Condition

Asset Category		# asset units				# asset units				# asset units				# asset units			
		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
Conductor	All	NA	NA	NA	NA	120,485	NA	NA	NA	122,539	NA	NA	NA	122,660	NA	NA	NA
	Overhead	NA	NA	NA	NA	111,703	NA	NA	NA	113,343	NA	NA	NA	113,299	NA	NA	NA
	Underground	NA	NA	NA	NA	5,474	NA	NA	NA	5,449	NA	NA	NA	5,569	NA	NA	NA
AMI	All	NA	NA	NA	NA	5,912	NA	NA	NA	6,507	NA	NA	NA	7,033	NA	NA	NA
	Retails Meters	NA	NA	NA	NA	11,776	NA	NA	NA	12,265	NA	NA	NA	12,299	NA	NA	NA
	Collectors	NA	NA	NA	NA	11,490	NA	NA	NA	11,996	NA	NA	NA	12,156	NA	NA	NA
	Repeaters	NA	NA	NA	NA	286	NA	NA	NA	269	NA	NA	NA	143	NA	NA	NA
Switches	Air Break & Load Break - 3 Phase	NA	NA	NA	NA	2,281	NA	NA	NA	2,277	NA	NA	NA	2,273	NA	NA	NA
Reclosers (Note 3)	All	NA	NA	NA	NA	2,902	NA	NA	NA	2,868	NA	NA	NA	2,856	NA	NA	NA
	Hydraulic	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Electronic	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Regulators		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacitor Banks		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA	This implies that there is no condition algorithm for this asset class, however defect and/or testing data exists
Note 1	Condition algorithms have not been developed to this level of granularity for this asset sub-type.
Note 2	Condition algorithms were not refined until 2017
Note 3	Assumed this refers to line reclosers

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.

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		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	Note 1	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.

School Energy Coalition Interrogatory # 45

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: 1

Interrogatory:

Has Hydro One's asset strategy changed since its EB-2013-0416 application? If so, please explain the changes and their rationale.

Response:

Hydro One's distribution assets are made up of many components and each component has a unique asset strategy based on its individual characteristics. For a list of asset components and their current strategy, please refer to Table 36 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.

These asset strategies remain essentially unchanged since Hydro One's last application (EB-2013-0416), with one notable exception – Hydro One's strategy for managing its distribution rights-of-way. Under the new vegetation management strategy, all rights-of-way will be assessed and maintained on a 3 year cycle focusing on correcting defects as opposed to the previous practice of complete clearing of rights of way. For further details on changes and rationale for the new vegetation management strategy please refer to Section 2.1 in Exhibit Q, Tab 1, Schedule 1.

b) to c) Please refer to the tables below for a summary of 2018-2022 planned costs and total candidate investments for distribution investments at the various investment planning stages.

Investment Development					**# of Candidate Investments**
2018	**2019**	**2020**	**2021**	**2022**	
$M	$M	$M	$M	$M	
1,412.2	1,479.7	1,390.0	1,403.1	1,514.5	393

Investment Optimization					**# of Candidate Investments**
2018	**2019**	**2020**	**2021**	**2022**	
$M	$M	$M	$M	$M	
1,265.9	1,328.8	1,258.0	1,268.6	1,361.2	391

Investment Approval and Implementation					**# of Candidate Investments**
2018	**2019**	**2020**	**2021**	**2022**	
$M	$M	$M	$M	$M	
1,198.6	1,324.9	1,296.4	1,315.5	1,408.1	410

d) The total number of candidate capital and OM&A investments at the Investment Development stage was 393 in comparison to the final investment plan having 410 investments. The majority of changes that occurred during the investment process resulted in a change to the level of funding for programs or projects time shifting within the planning horizon. This resulted in a total reduction of $656 million over the five years from initial candidate Investment Development to Final Investment Approval and Implementation.

e) See Exhibit I-24-AMPCO-36 for additional information.

Association of Major Power Consumers in Ontario Interrogatory # 4

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 1.0 Page: 14

Interrogatory:

a) Please explain the process used to retain AESI Inc.

b) Please provide a copy of the Terms of Reference for AESI Inc.

Response:

a) See Exhibit I-24-SEC-46.

b) See Exhibit I-24-SEC-46.

UNDERTAKING – JT 3.7

Undertaking

To break down each of the three steps into the four spending categories. So system access, system renewal, general plant, so we understand not just what the changes were overall but in which categories.

Response

The tables below reflect a summary of 2018-22 planned costs for distribution investments at the various investment planning stages, broken down into the OEB categories of System Access, System Renewal, System Service, General Plant and System O&M.

	Investment Development ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	163.5	166.2	170.0	173.1	177.5
System Renewal	385.1	392.9	392.1	412.9	501.1
System Service	90.2	103.0	86.1	70.4	82.0
General Plant	171.1	205.0	125.0	122.4	120.9
Total Capital	**809.9**	**867.1**	**773.1**	**778.7**	**881.4**
System O&M	602.3	612.6	616.9	624.4	633.1
Total	**1,412.2**	**1,479.7**	**1,390.0**	**1,403.1**	**1,514.5**

	Investment Optimization ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	163.5	166.2	170.0	173.1	177.5
System Renewal	264.9	273.8	275.6	288.2	375.2
System Service	84.3	93.2	93.8	86.2	77.0
General Plant	170.1	203.7	121.7	116.0	117.4
Total Capital	**682.9**	**736.7**	**661.1**	**663.4**	**747.1**
System O&M	583.0	592.1	596.9	605.2	614.1
Total	**1,265.9**	**1,328.8**	**1,258.0**	**1,268.6**	**1,361.2**

Witness: JESUS Bruno

	Investment Approval and Implementation ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	154.6	157.6	160.9	163.8	167.8
System Renewal	248.6	318.7	336.7	356.5	445.1
System Service	81.8	93.4	85.6	77.6	68.2
General Plant	149.0	187.1	135.8	133.4	136.6
Total Capital	**633.9**	**756.8**	**719.0**	**731.3**	**817.7**
System O&M	564.6	568.1	577.4	584.2	590.4
Total	**1,198.6**	**1,324.9**	**1,296.4**	**1,315.5**	**1,408.1**

Table above excludes integration of Acquired Utilities in 2021/22.

Association of Major Power Consumers in Ontario Interrogatory # 36

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:

Q-01-01 Page: 11

Interrogatory:

a) Please provide the start and end date for each of the seven planning process stages.

b) Please provide the level of investment and number of projects at each of the following stages:

c) 4. Investment Development, 5. Investment Optimization and 6. Investment Approval and Implementation.

d) Please provide the number of candidate investments under 2.1.4 Investment Development compared to the final investment plan.

e) Please provide the % of plans that were optimizable in this business cycle.

Response:

In Exhibit I-24AMPCO-1, AMPCO poses the same questions based on the original business plan that was the basis of this Application. Because the Application (originally filed in March 2017) is still before the OEB, Hydro One did not re-run its investment planning process for its distribution business. Only the investments common to transmission and distribution were revisited.

a) Refer to Exhibit I-24-SEC-36.

b) to c) The investment development and investment optimization tables remain unchanged from those shown in Exhibit I-24-AMPCO-1. The Investment Approval and Implementation table resulting from the modifications described in Exhibit Q-01-01-01 are shown below.

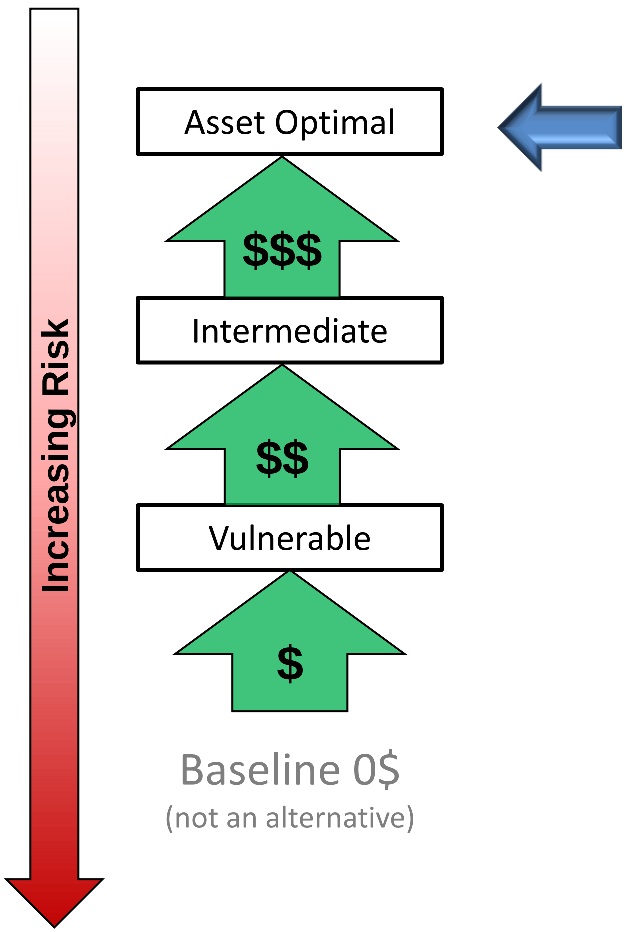
Investment Approval and Implementation					**# of Candidate Investments**
2018	**2019**	**2020**	**2021**	**2022**	
$M	$M	$M	$M	$M	
1,197.6	1,311.6	1,282.7	1,294.5	1,386.8	412

d) The total number of candidate capital and OM&A investments at the Investment Development stage was 393 in comparison to the final investment plan having 412 investments. The majority of changes that occurred during the investment process resulted in additional cost reductions and implications to investments common to Hydro One's transmission and distribution businesses stemming from OEB's decisions on Hydro One's 2017-2018 transmission application (EB-2016-0160) when compared to the Investment Approval and Implementation shown in part b) of Exhibit I-24-AMPCO-1. This resulted in a total reduction of $726 million over the five years from initial candidate Investment Development to Final Investment Approval and Implementation.

e) The chart below indicates the level of investment that was optimizable for the 2018-2023 business cycle in comparison to previous cycles.

Optimizable portion of the plan		
2016-2010 Cycle	**2017-2022 Cycle**	**2018-2023 Cycle**
%	%	%
32	23	67

Program Alternatives



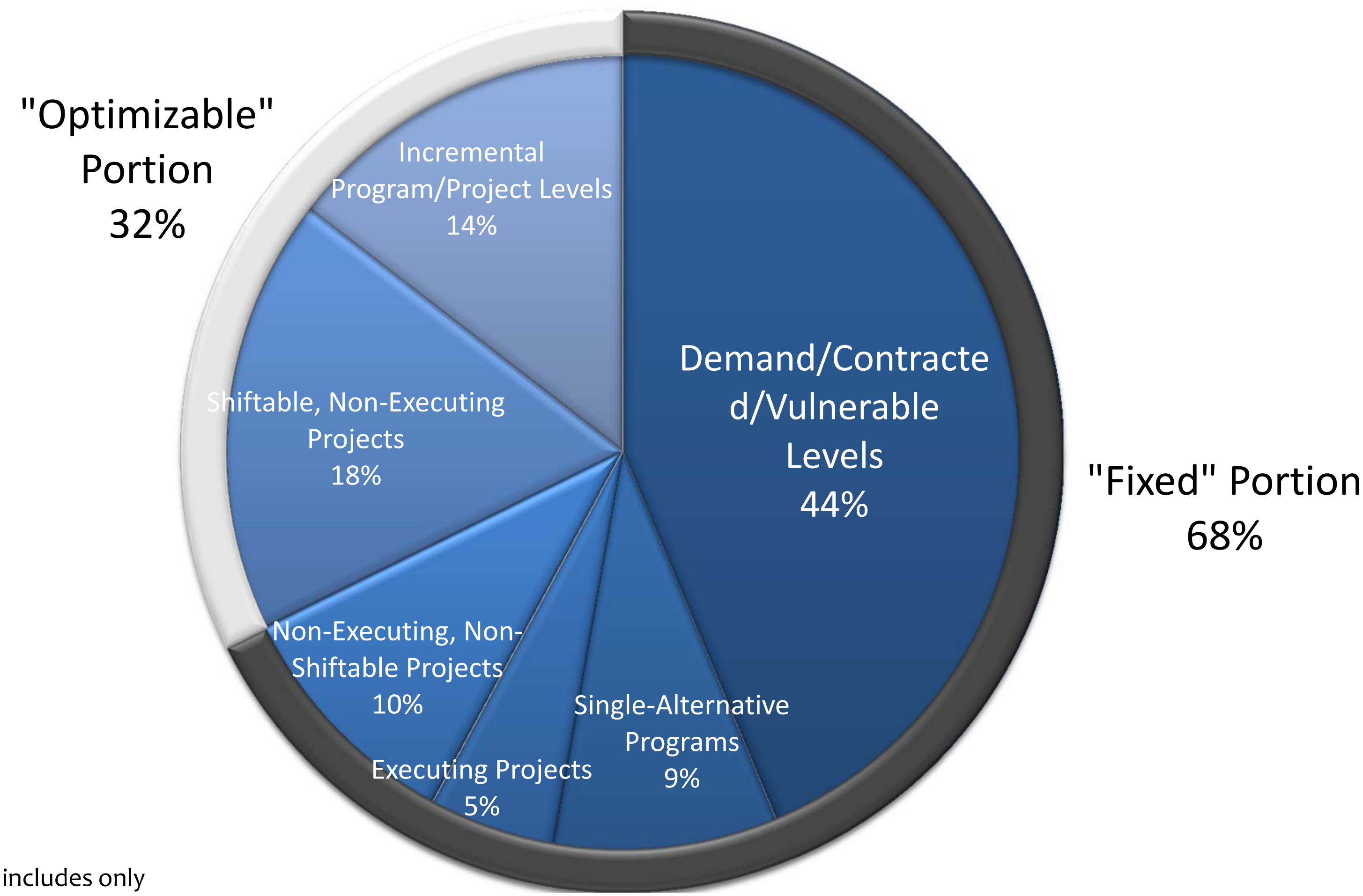
Recommended or Proposed Alternative should align to your Investment Strategy based on your analysis and in turn align with the Corporate Strategy

Every Alternative is a valid option for consideration

Note: Demand Programs will only have one alternative

Investment Plan Optimization

5-Year Net Total (2016-2020)



As of May 14, 2015; includes only selectable alternatives

Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Association of Major Power Consumers in Ontario Interrogatory # 22

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 2.1 Page: 32

Preamble: The evidence states that Hydro One performs a comparison between the actual investment costs and accomplishments and the proposed investment plan throughout the year and at the end of the investment plan years.

Interrogatory:

a) Please provide this analysis for the years 2014 to 2017.

b) Please provide the % of planned capital work undertaken for each of the years 2012 to 2017.

Response:

a) Please refer to Exhibit I-24-SEC-42 for the comparison between proposed and actual investment costs.

   Table 1 compares the accomplishments reflected in Hydro One's last custom distribution application (EB-2013-0416) and actual accomplishments. (Note that 2012-2014 were IRM years.)

Witness: JESUS Bruno

Table 1

Asset/Project Type	**ISD**	**2015 Variance**	**2016 Variance**	**2017 Variance**
Transformer Replacements	S-01	2	-3	-1
Transformer Spares	S-01	14	-20	-21
MUS Trailer Replacements	S-02	-2	-3	-1
MUS Purchases	S-02	-1	-1	0
Stations targeted for Spill Containment	S-03	-1	-1	-2
Feeders identified for Recloser Upgrades	S-05	-13	-9	-8
Station Refurbishments	S-07	-8	-27	-29
Pole Replacements	S-10	237	-903	-3558
PCB Lines Equipment Replacements	S-11	-366	-653	-2200
Large Sustainment Initiatives	S-12	1	-5	-9
Development Capital - New Connections	D-01	-2391	87	1423
Development Capital - Service Upgrades	D-01	-594	-424	-719
Development Capital - Service Cancellations	D-01	-911	1670	-1556
Upgrades Driven by Load Growth	D-02	-9	-6	2
Asset Life Cycle Optimization and Operational Efficiency	D-05	-5	-3	0
Reliability Improvements	D-06	-1	-2	-1
Distribution Station Security Upgrades	C-05	-3	0	-3

b) For the 2013-2016 period, please refer to Tables 54-55 in section 3.2 of the DSP (Exhibit B1, Tab 1, Schedule 1) on pages 2509-2512 of 2930. For 2017 figures, please refer to Exhibit I-24-AMPCO-033. Note that 2012 was an IRM year, so no proposed figure is available.

School Energy Coalition Interrogatory # 42

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

Interrogatory:

Please complete the shaded cells in the attached excel spreadsheet.

Response:

Please refer to the updated Exhibit I-24-SEC-42-01. The subtotals for 2015, 2016 and 2017 Sustainment, Development, Operations, Customer Service and Common Corporate Costs capital as well as the total capital shown in the attachment will not match up to those reflected in DSP Section 3.2 Table 55. This is because only investments included in EB-2013-0416 have been reported.

2018-2022 forecasts cannot be provided in the format presented. ISDs referenced in Exhibit I-24-SEC-42-01 are as per the 2013 filing; investments in future years are categorized into new ISD groups that cannot be accurately mapped to the old groups. For future forecasts of Sustainment, Development, Operations, Customer Service, and Common Corporate investments, please refer to DSP Section 3.2.

Witness: BRADLEY Darlene

24-SEC-42

Please completed the shadded areas

EB-2013-0416 - Ex.D2-02-02	EB-2017-0049

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $1M

1.0 SUSTAINING CAPITAL (Exhibit D1, Tab 3, Schedule 2)

1.1 Stations

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
S1	Transformer Spares and Replacements	18.0	18.4	17.9	21.2	21.6	20.4	7.6	5.2		*Refer to Exhibit B1-01-01.*			
S2	Mobile Unit Substations	4.6	3.6	3.7	3.6	3.7	0.3	0.9	2.8					
S3	Spill Containment	1.1	1.1	1.2	1.2	0.6	1.1	0.9	0.6					
S4	Station Component Replacements	2.1	2.2	2.2	2.2	2.3	4.3	2.8	0.9					
S5	Recloser Upgrades	1.4	1.4	1.4	1.5	1.5	0.7	3.0	2.6					
S6	Demand Work	2.1	2.1	2.1	2.2	2.2	1.6	2.7	3.5					
S7	Station Refurbishments	34.6	39.0	40.0	44.5	45.2	58.9	48.9	19.8					
													Total	

1.2 Lines

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
S8	Trouble Call and Storm Damage Response	58.2	60.8	61.6	62.0	62.5	74.8	84.2	87.0					
S9	Joint Use and Line Relocations	26.7	27.3	27.8	28.4	28.9	24.9	23.4	12.5					
S10	Pole Replacements	88.7	95.1	105.0	115.2	125.8	87.4	90.9	72.4					
S11	PCB Lines Equipment Replacements	1.9	5.0	10.6	10.8	11.1	0.2	1.4	0.0					
S12	Large Sustainment Initiatives	33.4	39.5	42.9	46.5	47.3	44.0	35.1	17.5					
S13	Line Component Replacements	11.6	11.8	12.1	12.3	12.6	11.3	9.8	3.2					
S14	Submarine Cable Replacements	7.1	7.2	7.4	7.5	7.7	7.5	8.0	7.3					
													Total	

1.3 Meters

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
S15	Meter Upgrades	10.0	15.8	18.8	16.1	5.0	30.2	24.4	16.7					
S16	Meter Inventory Sustainment	4.6	4.8	5.0	5.2	5.5	3.6	14.0	9.0					

Summary	2015	2016	2017	2018	2019								
Total Sustaining projects/programs listed above	306.2	335.2	359.7	380.4	383.5	371.2	358.1	261.0					
Sustaining projects/programs less than $1M	2.0	0.0	0.0	0.0	0.0	1.4	1.3	1.2					
Total Sustaining Capital (per Exhibit D1-3-1)	**308.2**	**335.2**	**359.7**	**380.4**	**383.5**	372.5	359.4	262.2					

2.0 DEVELOPMENT CAPITAL (Exhibit D1, Tab 3, Schedule 3)

2.1 Connections

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
D1	New Connections, Upgrades and Service Cancellations	108.9	112.1	115.8	119.3	122.9	114.2	110.1	131.7					

2.2 System Capability Reinforcement

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
D2	Upgrades Driven by Load Growth	20.1	26.4	28.5	30.8	32.9	20.7	24.1	14.6					
D3	Upgrades Driven by Load Growth - Distribution System Modifications	9.0	9.2	9.4	9.1	8.8	13.6	10.8	7.2					
D4	Upgrades Driveb by Load Growth - Demand Investments	3.6	3.7	3.8	3.4	3.4	2.9	3.2	4.8					
D5	Asset Lifecycle Optimization and Operational Efficiency	8.1	9.7	8.9	4.2	4.5	4.9	8.3	5.9					
D6	Reliability Improvements	2.7	2.0	2.6	1.6	2.2	1.2	0.5	0.3					
D7	Orleans TS Capital Contribution	21.0	0.0	0.0	0.0	0.0	5.1	3.1	0.7					
D8	Red Lake TS Capital Contribution	1.8	0.0	0.0	0.0	0.0	0.3	0.1	-0.1					
D9	Hanmer TS Capital Contribution	0.0	11.5	0.0	0.0	0.0	0.0	0.0	0.0					
D10	Enfield TS Capital Contribution	0.0	0.0	0.0	0.0	11.1	0.0	0.0	0.0					
D12	Leamington TS Capital Contribution	0.0	0.0	22.0	0.0	0.0	0.0	1.0	0.2					
													Total	

2.3 Distribution Generation Connection

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
D11	Recloser Retrofit Project	1.0	0.0	0.0	0.0	0.0	0.7	0.3	0.0					

Summary	2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
Total Development projects/programs listed above	176.2	174.6	191.0	168.4	185.8	163.5	161.4	165.3					
Development projects/programs less than $1M	47.1	31.7	16.7	15.1	13.3	22.8	13.4	23.797					
Total Development Capital (per Exhibit D1-3-1)	**223.3**	**206.3**	**207.7**	**183.5**	**199.1**	186.4	174.8	189.1					

3.0 OPERATIONS CAPITAL (Exhibit D1, Tab 3, Schedule 4)

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
O1	Operating Compute Refresh	0.0	0.0	0.0	0.9	1.9	0.0	0.0	0.0					
O2	NOMS Refresh	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0					
O3	Operating Facilities Refresh	0.0	0.0	0.7	2.1	1.4	0.0	0.0	0.0					
O4	BUCC - New Facilities Development	0.5	9.4	5.2	2.9	0.0	0.0	0.0	0.0					
O5	OGCC Storage Area Network Upgrade	0.0	0.0	1.2	1.2	0.9	0.7	0.0	0.0					
O6	ORMS Refresh	8.0	8.0	0.0	0.0	0.0	2.0	6.8	5					

Summary	2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
Total Operations projects/programs listed above	8.5	18.8	7.0	7.0	4.2	2.6	6.9	5.0					
Operations projects/programs less than $1M	0.9	0.0	0.0	0.0	0.0	1.6	0.5	0.0					
Total Operations Capital (per Exhibit D1-3-1)	**9.4**	**18.8**	**7.0**	**7.0**	**4.2**	4.2	7.3	5.0					

4.0 CUSTOMER SERVICE CAPITAL (Exhibit D1, Tab 3, Schedule 5)

Summary	2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
*Total Customer Service projects/programs***	22.4	8.0	1.5	0.0	0.0	5.2	17.2	18.9					
Customer Service projects/programs less than $1M	0.2	1.9	2.4	0.0	0.0	0.8	0.0	0.0					
Total Customer Service Capital (per Exhibit D1-3-1)	**22.6**	**9.9**	**3.9**	**0.0**	**0.0**	6.0	17.2	18.9					

**detailed information regarding these projects may be found in Table 1, Exhibit D1, Tab 3, Schedule 5

5.0 COMMON CORPORATE COSTS (Exhibit D1, Tab 3, Schedule 6)

5.1 Information Technology

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
IT1	Hardware/Software Refresh and Maintenance	12.0	11.2	10.1	10.1	10.1	12.4	16.4	14.1					
IT2	MFA Servers and Storage	7.1	9.3	8.0	5.3	5.3	6.1	1.9	5.4					
IT3	MFA PC and Printer Hardware	5.6	5.3	5.3	4.5	4.0	3.7	4.3	3.9					
IT4	MFA Telecom Infrastructure	2.7	2.9	2.5	2.8	2.9	1.1	1.9	1.7					
IT5	Field Workforce Optimization and Mobile IT	5.0	5.0	8.0	2.0	2.0	9.9	20.6	9					
IT6	Customer Experience	5.0	1.0	4.0	1.0	3.0	0.3	5.9	4.1					
IT7	Information Rights Management	0.0	0.0	0.0	2.5	2.5	0.0	0.9	0.2					
IT8	Enterprise Analytics	2.0	2.0	2.0	0.0	0.0	2.2	0.9	0.4					
IT9	Corporate Support Optimization	0.0	3.0	0.0	3.0	0.0	1.3	2.4	0.1					
IT10	Engineering Design Transformation	0.0	0.0	0.0	4.0	3.0	0.0	0.4	1.4					
IT11	Enterprise GIS	2.0	1.0	2.1	0.0	1.0	0.0	0.6	1.4					

5.2 Common Corporate Costs and Other

		2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
C1	Real Estate Head Office and GTA Facilities Capital	13.1	0.0	0.0	0.0	0.0	11.6	1.6	0.0					
C2	Real Estate Field Facilities Capital	26.5	31.5	31.5	36.5	36.5	7.0	28.5	18.9					
C3	Transport and Work Equipment	54.5	62.5	56.7	62.9	59.0	65.9	64.5	42.1					
C4	Service Equipment	9.1	7.9	7.9	7.0	7.0	7.0	6.2	5.6					
C5	Security Infrastructure Capital	1.0	1.0	1.1	1.1	1.1	0.0	1.3	0.2					

1.3 Meters

Summary	2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
Total Common Corporate Costs and Other projects/programs listed above	145.6	143.6	139.2	142.7	137.4	128.4	158.2	108.5					
Common Corporate Costs and Other projects/programs less than $1M	9.2	9.5	9.4	9.6	9.8	12.9	3.6	2.5					
(includes Transmission Security Infrastructure)													
Total Common Corporate Costs and Other capital (per Exhibit D1-3-1)	**154.8**	**153.1**	**148.6**	**152.3**	**147.2**	130.4	151.2	111.0					

Costs Allocated to Distribution	2015	2016	2017	2018	2019	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F
Total Common Corporate Costs and Other capital (per Exhibit D1-3-1)	**85.4**	**84.5**	**83.1**	**84.2**	**82.3**	89.2	108.1	102.3					

School Energy Coalition Interrogatory # 52

Issue:

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1

Interrogatory:

Please complete the shaded cells in the attached excel spreadsheet, providing the number of assets/ projects completed between 2015 and 2017, and forecasts to be completed between 2018-2022, on the same basis as provided in EB-2013-0416. Please explain all material variances from what was provided in the EB-2013-0416 evidence.

Response:

Please refer to Attachment 1 to this response.

29-SEC-52

Please complete the shaded area

Asset/Project Type	ISD	EB-2013-0416 Pre-Filed Evidence [# Asset/Project] 2015F	2016F	2017F	2018F	2019F	EB-2017-0049 [# Asset/Project] 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.*

		EB-2013-0416 - Ex.D2-02-02									EB-2017-0049									Comparison		
	SUSTAINING CAPITAL (Exhibit D1, Tab 3, Schedule 2)	Cost ($M)			Assets			Unit Cost ($M)			Cost ($M)			Assets			Unit Cost $M)			Unit Cost Comparison		
	Stations	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015A**	**2016A**	**2017A**	**2015A**	**2016A**	**2017A**	**2015A**	**2016A**	**2017A**	**2015**	**2016**	**2017**
S1	Transformer Spares and Replacements	18.0	18.4	17.9	32	33	32	0.563	0.558	0.559	20.4	7.6	5.2	48	10	10	0.426	0.763	0.520	75.7%	136.9%	93.0%
S2	Mobile Unit Substations	4.6	3.6	3.7	3	4	2	1.533	0.900	1.850	0.3	0.9	2.8	0	0	1	#DIV/0!	#DIV/0!	2.800	#DIV/0!	#DIV/0!	151.4%
S3	Spill Containment	1.1	1.1	1.2	2	2	2	0.550	0.550	0.600	1.1	0.9	0.6	1	1	0	1.082	0.919	#DIV/0!	196.7%	167.0%	#DIV/0!
S4	Station Component Replacements	2.1	2.2	2.2							4.3	2.8	0.9									
S5	Recloser Upgrades	1.4	1.4	1.4	17	22	18	0.082	0.064	0.078	0.7	3.0	2.6	4	13	10	0.175	0.232	0.260	212.7%	365.3%	334.3%
S6	Demand Work	2.1	2.1	2.1							1.6	2.7	3.5									
S7	Station Refurbishments	34.6	39.0	40.0	36	38	38	0.961	1.026	1.053	58.9	48.9	19.8	29	11	9	2.031	4.443	2.200	211.4%	432.9%	209.0%
	Lines	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015**	**2016**	**2017**	**2015A**	**2016A**	**2017A**	**2015A**	**2016A**	**2017A**	**2015A**	**2016A**	**2017A**	**2015**	**2016**	**2017**
S8	Trouble Call and Storm Damage Response	58.2	60.8	61.6							74.8	84.2	87.0									
S9	Joint Use and Line Relocations	26.7	27.3	27.8							24.9	23.4	12.5									
S10	Pole Replacements	88.7	95.1	105.0	11600	12200	13200	0.008	0.008	0.008	87.4	90.9	72.4	11837	12355	9642	0.007	0.007	0.008	96.5%	94.4%	94.4%
S11	PCB Lines Equipment Replacements	1.9	5.0	10.6	400	1000	2200	0.005	0.005	0.005	0.2	1.4	0.0	34	347	0	0.007	0.004	#DIV/0!	142.4%	79.0%	#DIV/0!
S12	Large Sustainment Initiatives	33.4	39.5	42.9	11	11	11	3.036	3.591	3.900	44.0	35.1	17.5	12	6	2	3.669	5.853	8.750	120.8%	163.0%	224.4%
S13	Line Component Replacements	11.6	11.8	12.1							11.3	9.8	3.2									
S14	Submarine Cable Replacements	7.1	7.2	7.4							7.5	8.0	7.3									

Sources: Cost 24-SEC-42; Assets 24-SEC-52

School Energy Coalition Interrogatory # 31

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 Page: 13

Interrogatory:
For each of the outcome measures provided in Table 9, please provide the targets for 2014-2016 that Hydro One provided in EB-2013-0416. For any target not achieved, please provide an explanation.

Response:

Year	Target			Actual		
	2014	2015	2016	2014	2015	2016
Vegetation Caused Interruptions	6,300	6,300	6,300	6,540	6,944	7,439

Vegetation Caused Interruptions did not achieve the target due in large part to the outstanding provincial backlog of 29% described in DSP Section 2.3.2.2. Hydro One is addressing this issue via the revamped vegetation management program described in Exhibit Q, Section 1, Tab 1. This program is designed to focus on defect correction on a significantly broader scale in order to reduce backlogs and provide better outcomes for customers.

Year	Target			Actual		
	2014	2015	2016	2014	2015	2016
Substation Caused Interruptions	155	155	155	158	141	103

Substation Caused Interruptions did not achieve the target in 2014 primarily due to an increase in station interruptions caused by equipment failure and foreign interference.

Year	Target			Actual		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Distribution Line Equipment Caused Interruptions	7,300	7,300	7,300	8,311	8,164	7,674

Line Equipment caused interruptions did not achieve the target because there were more equipment related failures due to deteriorating condition of the assets.

Year	Target			Actual		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Number of Replaced Poles	11,000	11,600	12,200	11,179	11,837	12,355

The Number of Replaced Poles achieved or exceeded targets in all years.

Year	Target			Actual		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Number of Pole Top Transformers with PCB Oil	N/A	400	1,000	N/A	34	347

The Number of Pole Top Transformers with PCB Oil did not meet 2015 and 2016 targets primarily due to a redirection of funding that lead to reduced testing and thus contaminated units were not identified for replacement.

Year	Target			Actual		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Residential and Small Business Satisfaction (%)	80	81	82	67	70	66

Please refer to Exhibit I-17-Staff-066, part a).

Year	Target			Actual		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Handling of Unplanned Outages Satisfaction (%)	80	80	83	75	76	83

Handling of Unplanned Outages Satisfaction (%) did not meet targets primarily due to reliable supply, number of outages, duration of outages, and communication with respect to estimated restoration times. Hydro One continues to employ methods to improve communication with customers including proactive outbound calls, and improved mobile communication capabilities. However, Hydro One believes the best way to improve this metric is to reduce unplanned outages. Key to addressing this is the new vegetation management strategy described in Exhibit Q, Tab 1, Section 1. Once established, this new methodology is expected to improve reliability outcomes for customers.

Year	**Target**			**Actual**		
	2014	**2015**	**2016**	**2014**	**2015**	**2016**
Estimated Bills Issued as % of Total Issued*	N/A	N/A	N/A	N/A	4	N/A

*No longer measured, replaced by Bill Accuracy measure.

This measure is no longer measured.

Witness: KIRALY Gregory

3.2 Outcome Metrics

The proposed areas to be measured are:

1. Vegetation Management;
2. Pole Replacement;
3. PCB Line Equipment;
4. Substation Refurbishments;
5. Distribution Line Equipment Refurbishments;
6. Customer Experience;
7. Handling of Unplanned Outages; and
8. Estimated Bills.

The areas to be measured have, for the most part, been tracked by the Company historically, so data is available against which to measure Hydro One's performance in each area. As will be evident from the following descriptions, the metrics were developed in an attempt to focus on two key issues: (1) was the planned investment made; or (2) were the desired results achieved.

Each of the proposed metrics against which to evaluate Hydro One's performance compared to the 5-year plan is outlined below. The Company will report actual performance for each of the outcome metrics on an annual basis.

Vegetation Management (Sustaining OM&A)

Service interruptions caused by vegetation are an issue faced by most electric distribution companies. Hydro One is proposing an outcome metric against which its efforts to reduce the number of vegetation caused outages will be evaluated.

Vegetation management expenditures related to line clearing are expected to be approximately $540 million in the 5-year forecast as compared to $338 million in the preceding 5 year period. The ramp-up is required to address tree clearing in order to allow Hydro One to move to an 8-year vegetation management cycle across the province.

The number of vegetation related customer outages on Hydro One's system over the last five years is set forth in the following table:

Table 1:
Vegetation Caused Interruptions
(Excluding Force Majeure Events)

	Actuals					Targets					
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Interruptions	**6,445**	**6,116**	**6,113**	**6,953**	**5,791**	**6,300**	**6,300**	**6,300**	**6,200**	**6,100**	**6,000**

The proposed metric for assessing Hydro One's performance with regards to vegetation management is:

- Reduction in vegetation related customer outages, annual targets for which, are shown in Table 1.

As vegetation is managed to achieve an 8-year vegetation management cycle, Hydro One expects that the number of outages caused by contact of trees with the distribution system will decline.

Pole replacement (Sustaining Capital)

Hydro One has approximately 1.6 million distribution poles in its system. Each year approximately 20,000 poles are installed, a figure that includes both new installations and end of life replacements. Poles that fail can cause customer outages. As such, Hydro One is targeting the replacement of poles as a metric against which the Company's performance can be measured.

At the end of 2011 an asset inventory was completed, and the detailed poles age information largely led to the proposed replacement ramp up. Hydro One is proposing increased funding to address premature decay issues and mitigate the risk of the approaching new wave of poles reaching their expected service life over the period. The plan ramps up replacement quantities each year so that approximately 4,500 additional end-of-life poles will be replaced per year by 2019. Total volumes of accomplishments over the five year plan are expected to be achieved. However, annual variances from the targets may occur due to the complexity of the specific poles to be replaced within a given year.

Hydro One expects to spend approximately $530 million on pole replacements during the course of the 5 year plan. Approximately $323 million was spent on pole replacements during the previous 5 year period.

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**

It is possible the number of transformers needing replacement may be less than the projected volume of replacements. In that case, the number of transformers replaced, will be reported.

The PCB line equipment capital project was selected as an area to be measured via an outcome metric because of the public safety issues pertaining to the equipment. The initiative addresses Federal PCB regulations and ensures Hydro One's communities' environmental concerns are addressed by decreasing the number of pole top transformers containing PCBs.

The budget for replacing PCB line equipment is approximately $39 million over the term of the 5 year plan. Approximately $4 million had been spent replacing PCB pad-mount transformers in the previous 5-year period.

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

- Number of pole top transformers with PCB oil that have been replaced as shown in Table 3.

Substation Refurbishments (Sustaining Capital)

Hydro One maintains 1,004 distribution and regulating station facilities, with an average expected service life of 50 years. The Company is proposing increased funding in this area to manage system reliability in the face of demographic and load requirement pressures on the system, and to mitigate against a growing wave of stations reaching expected service life simultaneously.

Hydro One's distribution system has experienced a number of substation related outages over the last five years. The following table summarizes the number of historical outages:

Table 4:
Substation Caused Interruptions
(Excluding Force Majeure Events & Excluding Planned)

	Actuals					Targets					
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Interruptions	**153**	**190**	**159**	**144**	**129**	**155**	**155**	**155**	**155**	**155**	**155**

The Company has identified substation related outages as an area to be addressed in the 5 year plan. The projected level of capital spent on substation refurbishments is expected to be $203 million during the 5-year plan period compared to $46 million in the preceding 5 year period.

The proposed metric for assessing Hydro One's performance with regards to substation refurbishments is:

- Number of substation interruptions over the five year period, as shown in Table 4.

Hydro One's goal is to reduce the number of substation interruptions during the 5 year plan.

Distribution Line Equipment Refurbishments (Sustaining Capital)

Hydro One owns over 120,000 circuit km of lines (approximately 3200 feeders). An ongoing assessment of the condition of the lines/feeders is performed by Hydro One. Small and large sustainment projects will be performed over the course of the 5-year plan to improve or sustain the performance of the system. Hydro One anticipates expending approximately $307 million on line projects during the 5-year plan period compared to $155 million in the preceding 5 year period.

Hydro One's distribution system has experienced a number of line equipment related outages over the last five years. The following table summarizes the number of historical outages:

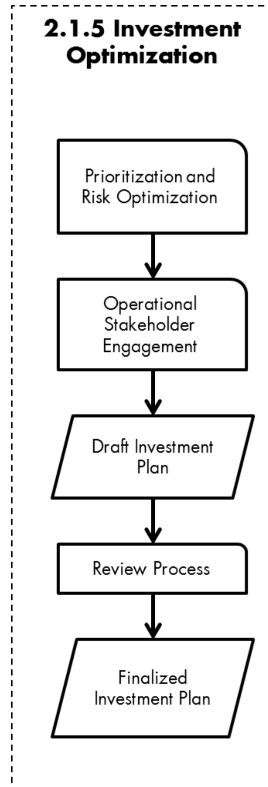
Table 5:
Distribution Line Equipment Caused Interruptions
(Excluding Force Majeure Events)

	Actuals					Targets					
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Interruptions	**8210**	**5,971**	**7,681**	**7,316**	**7,266**	**7,300**	**7,300**	**8,300**	**7,300**	**7,300**	**7,300**

The proposed metric for assessing Hydro One's performance with regards to line projects is:

- Number of distribution line equipment interruptions over the five year period, targets for which are shown in Table 5 .

2.1.5 (5.3.1 B) INVESTMENT OPTIMIZATION



This section details the investment optimization process that takes identified candidate investments and yields a finalized investment plan.

2.1.5.1 PRIORITIZATION AND RISK OPTIMIZATION

All candidate investments are aggregated into a consolidated investment plan for prioritization and optimization. At the core of the process is the multi-variable framework based on the business objectives, which helps decision-makers understand and quantify business risks and uncertainties so that objective decisions can be made respecting investment priorities.

For the purpose of prioritizing investment candidates, the Business Objectives outlined in Section 2.1.1 are translated into a series of prioritization criteria, against which candidate investments are assessed. The prioritization criteria are assigned weights based on their relative importance within the Business Objectives as shown in Table 34.

Table 34 - Hydro One's Prioritization Criteria and Weightings

Prioritization Criteria	Business Objectives	Weighting (Pts)	Weighting (%)
Customer	• Improve current levels of customer satisfaction • Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes	20	17%
Safety	• Drive towards achieving an injury - free workplace	20	17%
Reliability	• Provide reliability consistent with customer requirements	15	13%
Productivity	• Actively control and lower costs through OM&A and capital efficiencies	15	13%
Employees	• Achieve and maintain employee engagement	10	9%
Shareholder Value	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario	10	9%
Environment	• Sustainably manage our environmental footprint	10	9%
Financial Benefit	• Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts	15	13%

The prioritization process attempts to find the combination of investment options that maximize investment benefit without exceeding the defined funding constraints. This iterative process is intended to produce an overall plan of appropriately paced investments that achieves an optimal balance between cost effectiveness, timely responsiveness to customer needs, asset requirements and business needs. This iterative process is a key stage in the process and it is what lead to the determination of Plans A, B and C as described in Section 1.1 and Section 2.4

Witness: Darlene Bradley

UNDERTAKING - TCJ1.21

Undertaking

References: Exhibit A, Tab 17, Schedule 7
Exhibit I, Tab 3.02, Schedule 1, Staff 50

To describe in general how weighting of the risks works, and to provide an example.

Response

At Hydro One, risks are weighed against each other at the Business Value level. The Business Values are outlined in Exhibit A, Tab 17, Schedule 4 (Investment Prioritization Process).

To determine the relative risk weightings, a risk workshop is held with our Executive Committee and other key senior business leaders on an annual basis. The workshop is designed to determine the level of uncertainty of achieving strategic goals that the corporation can tolerate. A risk matrix is used as a guide to determine the tolerance levels. The scores are then normalized on a scale of 1-100. The results are presented to the team and adjusted until consensus is achieved. The relative risk weightings for the corporate business values are set out in Table 1.

Table 1

	Risk Weightings
Reliability	20%
Productivity	15%
Safety	20%
Environment	5%
Customer	15%
Financial Benefit	15%
Shareholder Value	5%
Employee	5%
	100%

In the process of determining the risk mitigated for a proposed investment, one or more applicable business values are evaluated for the risk being mitigated. For each business value, for the risk mitigated, the result is then multiplied by the specific risk weighting in Table 1 to determine the total value of risk mitigated for a particular business value. Table 2 illustrates how the calculation works for a single expenditure.

OEB Staff Interrogatory # 121

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:

Office of Auditor General of Ontario – Annual Report 2015 (Rec. 17)

The Auditor General's report recommended the following:

"To ensure that management can better manage and monitor capital projects that use its own workforce, as well as lower project costs, Hydro One should:

- *use industry benchmarks to assess the reasonableness of capital construction project costs, and whether using internal services and work crews is more economical that contracting out capital projects*

- *use and adhere to contingency and escalation allowances that are more in line with industry norms for capital construction projects*

- *improve its management reporting and oversight of project costs by regularly producing reports that show actual project costs and actual completion dates compared to original project cost estimates, cost allowances used, original approved costs, subsequent approvals for cost increases, and planned completion dates; and*

- *regularly analyze its success in preparing project estimates by comparing them with final project costs."*

Interrogatory:

a) Please provide the 5 year historical percentage used as project contingency and compare that to the current.

b) In Excel format, please provide a list of capital project that triggered a change control process in the last five years (eg. Project costs that exceeded approved capital, and change in project scope/timeline). For each project in this list please provide the documentation provided to management in the form of change control log.

c) Does Hydro One have a unit costing database for the purpose of preparing estimates? If not, how does Hydro One ensure each project estimate is accurate? If yes, please provide the database, Also if yes are the unit costs based on historical actuals and how often are the unit rates updated?

d) How does Hydro One incent efficient completion of capital projects to mimic a competitive market?

Response:

a) Currently, the Company allocates a standard 10% contingency to its Distribution investments, although major projects (greater than $5M) will have a refined risk based contingency allocation that may vary slightly from the 10%. Since 2012, Hydro One has refined its estimating and field execution such that it has significantly reduced contingency usage over the past 6 years, reducing our contingency usage from 75% to less than 20% last year.

Year	Percentage of contingency used
2012	68%
2013	76%
2014	74%
2015	55%
2016	44%
2017	19%

b) Please refer to Exhibit I-24-Staff-121, Attachment 1.

c) No, Hydro One does not have a costing database for the purpose of preparing estimates.

For smaller investments (less than $5 million) - Hydro One estimates are built utilizing compatible units which are stored in SAP. The compatible units are made up of either a labour and/or material component which are based on historical actual labour hours, and material requirements. This is then combined with current rates to determine the dollar values for labour and material costs. To ensure each project estimate is accurate, the compatible unit historical hours and material requirements are being reviewed in 2018.

For Larger investments (greater than $5 million) – Hydro One estimates are prepared using a bottom up approach with defined engineering deliverables. The estimates are built based on common construction tasks and their corresponding benchmarks which are continuously refined. This process results in a detailed class A (±10%) estimate being produced with a detailed risk registry and associated contingency allocation. Upon the project energization we complete a lessons learned and project closeout process in which we review the execution and incorporate any lessons into the upfront planning and engineering for future projects.

d) Hydro One drives efficient completion of capital projects through the following areas:

- Detailed review and critique of all variances.
- Aggressive yearly performance targets to ensure the capital work program is delivered on budget
- Performance comparison of our regional work centers to illustrate improvement opportunities and drive a healthy competitive environment
- Benchmarking with other North American utilities

UNDERTAKING – JT 3.5

Undertaking

With reference to the Navigant Study, to break stations down into full station rebuilt, and substation-centric, with respect to the plan for 2018 and 2022.

Response

Of the seventy-three stations identified for refurbishment listed in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.7, ISD SR-06 Distribution Station Refurbishments, Hydro One Distribution estimates that eleven will be full station rebuilds and sixty-two will be substation-centric refurbishments. The breakdown of full station rebuilds versus substation-centric refurbishments is subject to change following the completion of individual scope documentation for each station.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**
VOLUME:	**Technical Conference**	
DATE:	**March 5, 2018**	

a number of -- both these interrogatories you are asked what's the definition for -- what's Navigant's definition for these various projects that it benchmarks. And I couldn't find anywhere in the evidence -- and maybe it wasn't asked or you didn't provide it, how many full station rebuilds and substation-centric projects, meaning this definition, are you planning to do in the test period and what the cost of those are. Can you either point me to somewhere else, or are you able to provide that information?

MR. NETTLETON: Mr. Rubenstein, is the underlying question that you have whether Hydro One uses these definitions, which are from the benchmarking study --

MR. RUBENSTEIN: No --

MR. NETTLETON: -- from Navigant as part of its investment planning process?

MR. RUBENSTEIN: Well, it's a little different. You provided information that met these for the purpose of that benchmarking, and I am just trying to understand, so we have a benchmark of those costs, and I am just trying to understand, well, how are we, on a going-forward basis, are we meeting that benchmark cost? Where are we? We know in the past because it used historical data to get to this point. Now for the test period are there projects that meet these categories and would the unit costs of those be similar?

MR. NETTLETON: But the benchmarking studies are not forward-looking.

MR. RUBENSTEIN: Well, no, I understand that, but I -- well, I am trying to look at them in a forward-looking way.

MR. NETTLETON: No, I -- but -- so the investment planning exercise is forward-looking.

MR. RUBENSTEIN: Yes.

MR. NETTLETON: But we are applying definitions from a benchmarking study that are, by design, intended for a benchmark of past results. So it's -- I am just -- it's -- it seems like we have two different concepts going on here.

MR. RUBENSTEIN: Well, I am not sure I would agree. I mean, the question is are you doing projects that would meet these -- are you doing work that meets these definitions on a going-forward basis, putting aside the utilization of that information, and do you have the costs for those --

MR. NETTLETON: These fair. I mean, I guess the question is -- for Mr. Jesus and Ms. Garzouzi is do you use these terms, these definitions, when you carry out your planning -- your investment planning exercise.

MS. GARZOUZI: If I point you to Exhibit I, AMPCO 27 it has the number of stations that are planned over the period from 2018 to 2022. I am trying to tie it back to your question, Mr. Rubenstein. That gives you the station count.

MR. RUBENSTEIN: But the Navigant report breaks stations down into full station rebuilt and substation-centric and it provides definitions of both. So assume Navigant asked you to fill out the exact same form or whatever it asked you to do when they were gathering information on an historic basis and they were saying, with respect to your plan for 2018 and 2022, do the same thing; could you do it?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: Can you undertake to do so?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: That's JT3.5.

UNDERTAKING NO. JT3.5: WITH REFERENCE TO THE NAVIGANT STUDY, TO BREAK STATIONS DOWN INTO FULL STATION REBUILT, AND SUBSTATION-CENTRIC, WITH RESPECT TO THE PLAN FOR 2018 AND 2022

MR. RUBENSTEIN: And, I mean, just to simplify it, they maybe have asked you to do many different things and breaking the components down. I am just seeking how many of those top two categories and what the cost would be to do that work.

Can I ask you to turn to issue 24, Energy Probe 34? In this interrogatory, you were asked to break down certain reliability information, and the charts go from 2012 to 2016. Are you able to provide 2017 data when available?

MR. JESUS: Yes, we are. Actually, the 2017 is already there. And if you look at interrogatory I24-SEC-37, all the information is updated up to 2017. If you continue on, it's all there. The graphics aren't there, but the tables are all there.

MR. RUBENSTEIN: But this is broken down into urban and rural.

School Energy Coalition Interrogatory # 36

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:

Previous Proceeding - EB-2016-0160, J8.1, Attachment 1-2

Interrogatory:

Please provide a detailed chronology of material events in Hydro One's distribution planning process for the capital plan included in this application similar as to provide in Undertaking J8.1 in EB-2016-0160.

Response:

Table 1 provides the chronology of material events in Hydro One's distribution planning process up to filing this Application on March 31, 2017.

Table 1: Chronology of Material Events in Hydro One's Distribution Planning Process

Date	Activity Category	Activity
March 2015	Strategic Decision	OEB issues decision in Hydro One's 2015-2019 Dx Rate Application
April – November 5, 2015	Strategic Decision	Initial Public Offering (IPO) process occurs. Distribution figures cited in the IPO documentation were those approved in Hydro One's last rates Dx application 2013-0416 which were based on information known in 2013
November 2, 4, 2015	Strategic Decision	CEO/CFO Review of the Draft Investment Plan
November – December 2015	Strategic Decision	Discussion with Board of Directors regarding draft Business Plan. Decision made to undertake a detailed review of the organization with several goals, including a review of the potential for additional productivity and efficiencies.
December 2015	External	Auditor General Report issued.
January 2016	Strategic Decision	2016 budget approved by Hydro One's Board of Directors
April/May 2016	IPSOS Customer Engagement	Develop Dx Customer Engagement Content
May 9, 2016	IPSOS Customer Engagement	CEO Review of Customer Engagement workbook
May 13, 2016	IPSOS Customer Engagement	Workshop invites sent to potential participants

Witness: BRADLEY Darlene

May 18, 2016	IPSOS Customer Engagement	Online workbook send to coding
May 25, 2016	IPSOS Customer Engagement	Workshop deck sent to production
May 27, 2016	Business Planning	CEO/CFO validation of prioritization criteria and weightings
June 2, 2016	Business Planning	Dx investment planning process initiated for 2017-2022 Business Plan.
June 2-17	IPSOS Customer Engagement	Telephone survey targeted towards for residential, seasonal small business, and First Nations customers (representative sample)
June 2-23, 2016	IPSOS Customer Engagement	Online workbook available for residential and seasonal customers (representative sample)
June/July	IPSOS Customer Engagement	Online workbook available for residential and small business customers (open link sample)
June 8-June 24, 2016	IPSOS Customer Engagement	LDC/LDC/C&I customer workshops
June 2016	IPSOS Customer Engagement	Online workbook/survey booklet available for LDC/LDC/C&I customers
June 27-July 6, 2016	IPSOS Customer Engagement	Residential and Small Business customer focus groups
June 2016	Business Planning	Planners input candidate investments into AIP tool.
Late June 2016	IPSOS Customer Engagement	Initial themes identified through customer engagement shared with asset management leadership
July 2016	Business Planning	Management review of individual candidate investment proposals
Mid July 2016	Business Planning	Investment Calibration
July 18, 2016	IPSOS Customer Engagement	Draft Customer Engagement report from IPSOS
July 19, 2016	IPSOS Customer Engagement	Key themes identified through customer engagement shared with asset management leadership
August 18, 2016	IPSOS Customer Engagement	Final Customer Engagement report from IPSOS
Early-Mid August	Business Planning	Prioritization and risk optimization of candidate investments
Mid-August–Mid September	Business Planning	Operational stakeholder (“Enterprise”) engagement on preliminary list of prioritized investments.
September 16, 2017	Business Planning	CFO Review of Draft Investment Plan (Plan A/B)
September 27/28, 2016	Business Planning	CEO/CFO Review of Draft Investment Plan (Plan A/B)
October 11, 2016	Strategic Decision	Discussion with Board of Directors on Distribution Investment Plan (Plan A/B)
October 2016	Business Planning	Further scenario development, exploring opportunities to mitigate rate impacts
October 2016	Benchmarking	Final report of Hydro One Vegetation Management
October 19, 2016	Benchmarking	Final report of Hydro One Distribution unit cost benchmarking study for pole replacements and substation refurbishments

November 11, 2016	Strategic Decision	Progress of Distribution Investment Plan discussed with Hydro One Board of Directors (Plan A/B/C/B-Modified)
Mid-Late November	Business Planning	Business Plan developed, using the Investment Plan, overhead information, and productivity targets, to finalize plan figures (revenue requirement).
December 2, 2016	Strategic Decision	Business Plan presented to Hydro One Board of Directors

INTERNAL AUDIT REPORT

Auditor General Report 2016 Follow-up

To:

Greg Kiraly
Chief Operating Officer

and

Michael Vels
Chief Financial Officer

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Rick Haier	Chief Security Officer
Brad Bowness	VP, Transmission and Stations
Darlene Bradley	VP, Planning
Lyla Garzouzi	Director, Distribution Asset Management
Luis Marti	Director, Reliability Studies
Kathleen McCorriston	Director, Project Management
Scott McLachlan	Director, Planning Analytics
Chong Kiat Ng	Director, Transmission Asset Management
Additional Recipients	Email Distribution List

Final Report Issued: March 31, 2017
Draft Report Issued: November 25, 2016
Report Number: 2016-18

Lead Auditor: William Chan
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

On December 2nd 2015, the Office of the Auditor General of Ontario released its 2015 Annual Report in the Ontario Legislature. Within her report, the Auditor General presented 17 specific recommendations that related to Hydro One's business operations. In response to these recommendations, Hydro One formally committed to 37 actions, which were included in the Auditor General's published report. As part of its response, Hydro One stated that its Internal Audit group will oversee the Company's implementation of the recommendations where Hydro One believes they enhance reliability while balancing service and cost. Completion of the actions supporting Hydro One's response included in the Auditor General's report is important to the company since it can have an impact on the overall efficiency of work performed in maintaining its assets to ensure a safe, reliable, and cost effective electricity supply to its customers, as well as on the company's reputation. Thus, it is important that Executives and Board members of Hydro One be aware of the status of actions by Hydro One management so that any necessary remediation receives appropriate oversight.

The objective of this audit was to perform a follow-up review of Hydro One management actions in response to the Auditor General's recommendations. Early in 2016, management identified, assigned and scheduled 71 separate actionable tasks to address Hydro One's commitments. Our work involved a review of the status of these actions and the degree to which they address the issues (design effectiveness).

Our work included:

- A review of the available evidence supporting the status of actions in response to the 2015 Auditor General's Report, to provide assurance that a process is in place to address all of the recommendations. Only the actions planned for completion by September 30, 2016 were assessed in this review. Our assessments were conducted between October 3 and November 15.
- Updating our understanding of the key controls that provide assurance relative to the audit objective.
- Interviewing and discussion with the accountable management, staff and stakeholders regarding completeness of committed actions.
- Briefing management on any gaps throughout the review.
- Recommending improvements, where appropriate.

The scope of our work did *not* include an assessment of the propriety of the Auditor General's recommendations.

There were 8 actions that had target completion dates beyond September 30, 2016. These were not formally assessed as part of this audit and are identified in this report as "work in progress". These actions, along with those found to be partially or substantially complete in this review will be assessed as part of the future follow-up audit later in 2017 that is part of Internal Audit's approved 2017-2019 work program.

We noted that the following success factors were in place:

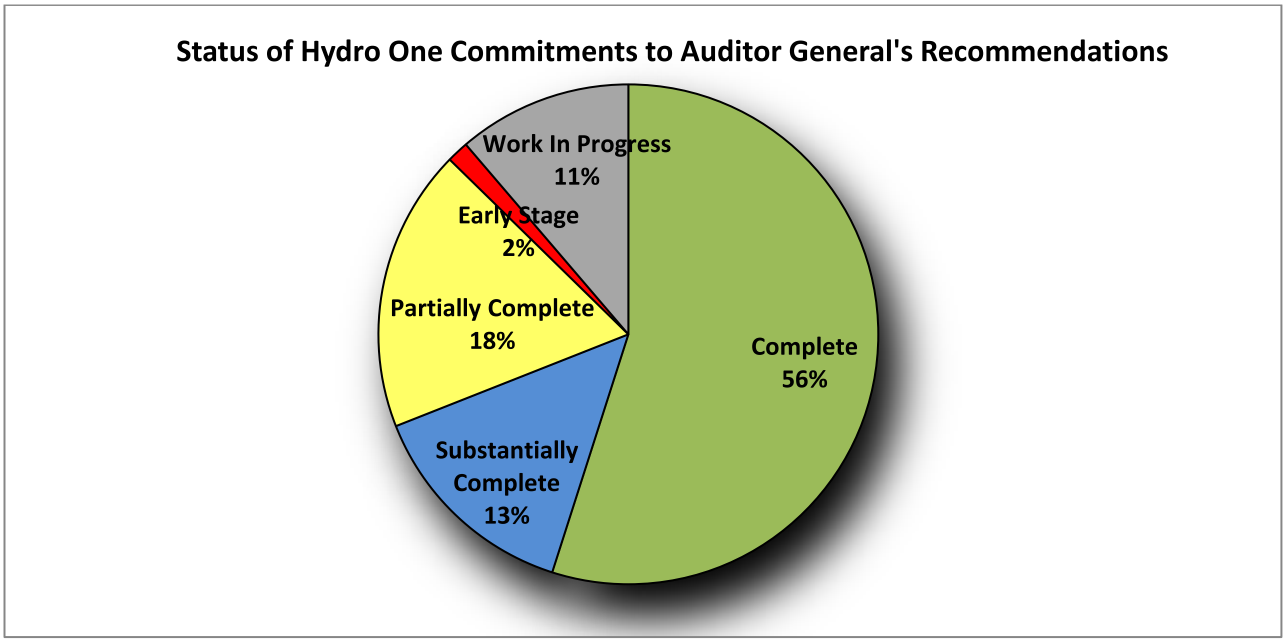
- A single accountable director was assigned to coordinate with the lines of business to establish, assign, prioritize, and schedule the required actionable tasks.
- A mechanism to track and report on all completed and outstanding actions was established.
- All actions were assigned a target completion date by the respective line of business directors with management status update comments provided at milestone points, June 30, 2016 and September 30, 2016 for most of the actions.
- The designs of controls for the actions assessed by Internal Audit as being either "complete" or "substantially complete" were found to be effective.
- Although we did not assess the Work In Progress items as part of this audit, we reviewed evidence provided by management and have observed that progress is being made on these management actions.

The following table shows the status of the actions at the conclusion of this review, with further details outlined in Appendix A, along with definitions of the assessment levels.

Auditor General Recommendations	Management Committed Actions	Actions Complete	Substantially Complete	Partially Complete	Early Stage	Work In Progress
17	71	40	9	13	1	8

* Definitions on the degree of completeness can be found in Appendix C.

The chart shown below provides an illustration of the summary status of Hydro One's actions as at September 30, 2016.



On June 30, 2016, management established target completion dates for all actions. Of the 63 actions due on or before September 30th, 2016, management reported 47 actions as complete.

We have shared our observations with management as summarized in Appendix A of this report. Meetings were held with responsible VPs and key stakeholders to review our findings. The objective of those meetings was not to elicit any management responses or action plans; rather to communicate the outcome of our review. Management demonstrated that it is committed to continue its efforts to complete all of the actions in support of the commitments made.

We would like to thank the management and staff in the Planning Optimization, Transmission Asset Management, Distribution Asset Management, Reliability Studies, Project Management, and Security Operations for their assistance during this review.

OBSERVATIONS, ASSESSMENTS, AND REQUIREMENTS TO COMPLETE

Observations	Assessment of Completion[1]	Assessment of Control Design Effectiveness[1]	Requirement to Complete[2]
AG Recommendation 1: Transmission System Reliability ○ Set targets and timetables, and cost-effective action plans, to improve the poor performance of its single-circuit transmission system. ○ More thoroughly analyze outage data on both its single- and multi-circuit systems to correct the main issues that are contributing to the system's declining reliability. ○ Set multi-year targets and timetables for reducing the frequency and duration of power outages that would lead to it having a system reliability and availability that compares favourably to other utilities in North America. ○ Establish an action plan and strategy for achieving these targets. ○ Regularly report publicly on its efforts to achieve these targets.			
• Planning has conducted a thorough analysis of outage data on both single and multi-circuit systems to identify factors affecting reliability. • Management is leveraging existing reliability measurement and analysis tools to perform detailed reliability analyses. • Although Planning conducted a cost-benefit analysis of planned maintenance activities, no evidence was provided to demonstrate how this information was incorporated into the investment plan. • Multi-year targets have not been established on reliability targets. Only 2017 reliability targets have been established.	Substantially Complete	Effective	a) Review the results of the cost/benefit analysis performed by Planning Optimization, with Transmission Asset Management with the objective to influence the investment planning process to drive reliability performance improvements, and determine the resulting impact on multi-year reliability targets. b) Complete tasks #3 and #6 as committed by management.
AG Recommendation 2: Backlog of Preventive Maintenance ○ Establish a timetable that eliminates its growing preventive maintenance backlog as soon as possible. ○ Improve its oversight of preventive maintenance programs to ensure maintenance is completed as required and on time.			
A Work Governance agreement was established between Asset Management(AM) and Station Services in October 2016 to clarify the accountabilities, authorities and process for work order tasks (incl. generation, prioritization, redirection, scheduling,	Complete	Effective	None

[1] The assessment of each section is an aggregate of individual task assessment. The assessment criteria are included in Appendix C.
[2] Task numbers referenced in this column are described in Appendix B.

cancellation and deferral), and communication between these lines of business. It also includes a high level reconciliation process that shows how AM will manage the expected year to year backlog of work orders. This process includes the review of the carry-over from unfinished work orders and how this will affect AM subsequent release of work for the follow year.			
AG Recommendation 3: Replacement of Transmission Assets at Risk of Failure ○ Ensure that its asset replacement program targets assets that have the highest risk of failure, especially those rated as being in very poor condition. ○ Re-assess its practice of replacing assets that are rated as being in good condition before replacing assets in very poor condition. ○ Replace assets that have exceeded their planned useful service life.			
• Evidence provided by management demonstrates that transmission power transformer replacements are supported by engineering reports. Transmission Asset Management (TxAM) reviews breakers by classification and type with replacement requirements based on the specific needs. These replacements are supported by engineering reports based on TxAM discretion. The criteria for breaker replacements are based on: Asset Analytics risk factors, health and safety requirements, environment, and obsolescence concerns. Currently, evidence shows that this information is available within the Station Assessment Report compiled by TxAM planners.	Complete	Effective	None
AG Recommendation 4: Accurate Reporting of Replacement Activities to the Ontario Energy Board ○ Hydro One should ensure that its applications for rate increases to the Ontario Energy Board provide accurate information on its asset replacement activities, including whether it actually replaced assets in poor condition that were cited in previous applications and whether the same assets in poor condition are being resubmitted to obtain further or duplicate rate increases in current applications.			
• Clear explanation regarding transformer and breaker replacements along with a list of transformers requiring replacement with planned in-service dates in 2017 and 2018 was provided to the Ontario Energy Board as part of the recent transmission rate filing[3].	Complete	Effective	None

[3] OEB Rate Application EB-2016-0160

AG Recommendation 5: Information Systems on Asset Condition incl. Asset Analytics

- Enhance its Asset Analytics system to include information on all key factors that affect asset investment decisions, including those related to technological/manufacturer obsolescence, known defects, environmental impact and health and safety.
- Review and adjust current weighting assigned to risk factors in Asset Analytics to more accurately reflect their impact of asset condition and risk of failure.
- Make changes to its Asset Analytics system and procedures so that updates to its data are complete, timely and accurate.
- Conduct a comprehensive review of the data quality in Asset Analytics to update any incomplete or erroneous information on its assets and to ensure the information can support its asset replacement decision making process.
- Investigate why known deficiencies in the reliability of the Asset Analytics system, such as those found two years earlier by internal audits, have not been corrected by management in a timely manner.

• Management demonstrated that its analytics tools continue to be maintained and improved: e.g. Google Earth view in Asset Analytics was replaced with Space Time Insight Interface, and the Transmission Lines Graphic Information System (TLGIS) work backlog was completed to make design changes visible. • Recent data remediation efforts were primarily focused on transmission data (due to the timing of the transmission rate filing) but did not adequately address distribution data integrity issues. The company's plan to develop a long term sustainable approach to management of data quality and completeness should upon completion, help mitigate the risk of continuing data integrity issues. • Three of the tasks have target completion dates at December 31, 2016 and remain as work in progress.	Partially Complete	Partially Effective	a) Completion of the design and implementation of the Data Governance project presently underway. b) Complete tasks #21 and #24 and work in progress tasks #16-18, as committed by management.

AG Recommendation 6: Quality of Asset Data

- Hydro One should ensure that its applications to the Ontario Energy Board for rate increases include accurate assessments of the condition of its assets.

• Management focused its efforts on remediating data completeness issues on transmission data at the time of the audit. Current data governance is not adequate to provide ongoing data completeness and data quality monitoring.	Substantially Complete	Effective	Completion of the design and implementation of the Data Governance project presently underway.

AG Recommendation 7: Spending to Maintain Transmission System Reliability ○ Conduct an assessment of its past maintenance expenditures and activities to determine what changes and improvements can be made to more effectively focus its efforts on the critical factors that improve system reliability and how its planned maintenance and capital improvements work can be completed with less risk of service disruption. ○ Benchmark cost assessments with other similar North American transmitters to compare its results with those that have reasonable expenditures and that maintain reliability. ○ Conduct a study of other leading cost-effective transmitters and consider implementing their best practices to quickly improve Hydro One's reliability and improve its costs.			
• A transmission benchmarking study was conducted by Navigant. The report reaffirms the need for Hydro One to increase capital expenditure due to deteriorated asset needs to stay within the reliability performance range of its peer group. • A comprehensive analysis comparing past maintenance expenditures with transmission reliability performance was completed. We have not seen evidence that demonstrates implementation of the analysis results into the investment plan. • The analysis performed by Planning Optimization identifies opportunities to reduce equipment outages through the bundling of preventive maintenance plans. The optimization approach has not been fully implemented.	Substantially Complete	Effective	a) Complete Requirement 1a as stated on page 3 of this report. b) Complete task #28 as committed by management which includes the implementation of a long-term metric to monitor the effectiveness of work bundling at the planning stage, in order to facilitate integrated outage scheduling and execution.
AG Recommendation 8: Security Framework on Electronic Devices ○ Ensure a robust and high level of security for the transmission system to mitigate the risk of service disruptions due to sabotage, vandalism, software viruses, and unauthorized or unintentional changes to device software or controls, Hydro One should develop a comprehensive security framework to cover all its electronic devices. The framework should include best practices for security over electronic devices, including establishing standards similar to those set by the North American Electricity Reliability Corporation, performing security vulnerability risk assessments on all electronic devices, establishing appropriate actions and controls to mitigate security risks to an acceptable level, and conducting regular audits to validate that the security framework has been adhered to.			
• Hydro One has completed the development of a comprehensive security framework. The framework is called the Hydro One Security Code of Practice and includes the Security Policy and Security Operating Standards for the organization which clearly defines at a high level, the governance, strategy, security access	Complete	Effective	None

controls (for both data and physical), training, monitoring, and resiliency planning.			
AG Recommendation 9: Distribution System Reliability ○ Establish more ambitious performance goals, targets and benchmarks for system performance. ○ Develop short- and long-term strategies for new and enhanced activities and cost-effective investments that will improve its overall reliability record.			
• A new feeder prioritization model was established by Distribution Asset Management (DxAM) to place a higher priority on reliability. • Although an end target for distribution reliability was established for 2022, multi-year targets as originally committed had not yet been established at the time of our follow–up. • Most Investment Planning Approval Documents (IPADs) are under development and in draft form. DxAM anticipates the need to update these documents pending the Board's recommendation on the appropriate funding level for the Investment Plan. Management informs us this work will be delayed to Q1, 2017.	Substantially Complete	Effective	a) Establish the appropriate funding level with senior management and the Board prior to 2017 Distribution Rate Filing. b) Based on the approved funding in the investment plan, DxAM needs to establish multi-year reliability targets and implement the new initiatives (programs) to specifically target improving distribution reliability performance.
AG Recommendation 10: Prioritization of Vegetation Management Work on the Distribution System ○ Shorten its current 9.5-year vegetation-management cycle to a more cost-effective cycle of less than four years, in line with other similar local distribution companies. ○ Change the way it prioritizes lines that need clearing so that lines with more frequent tree-related outages are given higher priority and work crews are dispatched sooner.			
• A new draft strategy has been established, communicated and stakeholdered with the service providers that includes on-cycle and strategic vegetation management approaches. • A review of the vegetation-management program and improvements on the prioritization model to support decision-making. Management reported a target completion date of December 31, 2016 so this task is still work-in-progress.	Substantially Complete	Effective	Complete the task #39, currently work in progress, as committed by management.

AG Recommendation 11: Quality of Data for Distribution Assets ○ 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.			
• An interface was established between the Distribution GIS and Asset Analytics to make recent design changes more visible. A test coordinated by ISD and Inergi shows that this interface is functioning properly. • Although recent data remediation efforts achieved success in reducing the number of data points that were found to be missing or incomplete, the focus had been on transmission data (to support the more immediate needs of the transmission rate filing). This effort had not yet addressed the data quality of distribution data at the time of our follow–up.	Substantially Complete	Effective	a) Complete task #42 as committed by management. b) Completion of the design and implementation of the Data Governance project presently underway.
AG Recommendation 12: Replacement of Distribution Assets at Risk of Failure ○ Replace assets that have exceeded their planned useful service life. ○ Reassess its planned expected service life for assets and justify any variances in the years used by Hydro One compared to other similar local distribution companies.			
• Distribution Asset Management (DxAM) has performed benchmarking studies with peer utilities on various maintenance programs including, pole replacements, station refurbishment, and vegetation management. The external study report from First Quartile/Navigant Consulting has informed and supports Hydro One's approach. For example, focusing the on-cycle vegetation management program on high priority/impact feeders (with high customer density, LDAs, and critical loads).	Complete	Effective	None

<table>
<tr><td colspan="4">AG Recommendation 13: Spending to Maintain Distribution System Reliability
○ Conduct an assessment of its past maintenance expenditures and activities to determine how to focus efforts on more critical factors that affect the system.
○ Benchmark cost assessments with other similar local distribution companies (LDCs) in Ontario and Canada, and consider implementing the best practices of the leading cost-effective LDCs.</td></tr>
<tr><td>• Benchmarking studies were conducted to inform and support management's approach to investment, maintenance, and sustainment activities, in preparation for the March, 2017 distribution rating filing.
• The asset planning documents for vegetation management, distribution station refurbishment, and pole replacement are delayed and remains as drafts due to activities required for the creation of the Distribution System Plan, were forecast for completion by December 31, 2016 at time of our review.
• There was no evidence provided to address the third party review of the Distribution System Plan. At the time of our review, Management informed us that the plan was still being developed with end of year as the target date of completion.</td><td>Partially Complete</td><td>Effective</td><td>Complete Tasks #46, 48 and 49 as committed by management.</td></tr>
<tr><td colspan="4">AG Recommendation 14: Smart Meter Capabilities to Improve Response to Power Outages
○ Lower its repair costs and improve customer service relating to power outages through more accurate and timely dispatches of its repair crews, Hydro One should develop a plan and timetable for using its existing smart meter capability to pinpoint the location of customers with power outages.</td></tr>
<tr><td>• The Advanced Metering Infrastructure for Operations and Analytics (AMIA) project charter has been created, reviewed and approved for implementation. This charter describes the solution that will be put in place to leverage installed smart meter capabilities to pinpoint the location of customers with power outages. At the time of our review, one management action had a target completion date of December 31, 2017.</td><td>Work In Progress</td><td>Not Assessed by Internal Audit in this review.</td><td>None</td></tr>
</table>

AG Recommendation 15: Operating Spares Management of Transmission and Distribution Transformers ○ Improve the forecasting model it uses for predicting transformer failures. ○ Maintain its inventory levels of spare transformers in accordance with the forecasts. ○ Develop a plan to standardize in-service transformers as much as possible. ○ Set targets and timelines for achieving savings from better managing both spare and in-service transformers.			
• As part of a more detailed audit of this area in the Operating Spare Management audit recently completed, Asset Management has committed to "…review the existing draft strategies and policies (for transmission and distribution operating spare requirement and management)…. make appropriate updates, stakeholder them and formally issue them for use."	Partially Complete	Effective	Complete management's commitment to review the existing draft strategies and policies on operating spares, make appropriate updates, stakeholder them and formally issue them for use.
AG Recommendation 16: Power Quality ○ Minimize the number and impact of power quality events for its large customers, Hydro One should proactively use the data collected by its power meters to help assess the frequency and location of power quality events on its transmission and distribution systems and thereby improve the reliability of the power supply.			
• The Company is implementing initiatives to address large customer power quality issues more proactively by providing power quality information to customers; and working with the information to estimate the frequency, duration, and magnitude of potential events that could have an adverse effect on its equipment and processes.	Complete	Effective	None
AG Recommendation 17: Oversight on Capital Project Costs ○ Use industry benchmarks to assess the reasonableness of capital construction project costs, and whether using internal services and work crews is more economical that contracting out capital projects. ○ Use and adhere to contingency and escalation allowances that are more in line with industry norms for capital construction projects. ○ Improve its management reporting and oversight of project costs by regularly producing reports that show actual project costs and actual completion dates compared to original project cost estimates, cost allowances used, original approved costs, subsequent approvals for cost increases, and planned completion dates. ○ Regularly analyze its success in preparing project estimates by comparing them with final project costs.			
• At the time of our review, one management action (#68) had a target completion date of December 31, 2017. (This action was not assessed as part of this	Substantially Complete	Effective	Complete task #68 as committed by management.

audit.) • All remaining management actions are complete and designed effectively (review project contingency and escalations, project closure process, comparison of project costs).			

Task Numbers referenced in Appendix A – Requirements to Complete

AG Recommendation	Task number	Management Commitments as of September 30, 2016
1	3	Set Multi-year reliability targets for 2016 to 2020 in 2016 Corporate Scorecard. Hydro One will determine if it is viable to continue participating in studies that include comparable utilities beyond the Canadian utility landscape.
	6	Revisit the maintenance plan strategies and costs to optimize equipment performance and costs (aligned to historical Tx-SAIDI equipment causes).
5	16	Re-visit and evaluate the augmentation of the Asset Analytics tool to include the additional risk factors (i.e. Environmental/Health & Safety, Obsolescence)
	17	Risk Algorithms Review: Conduct a review of the risk factors algorithms and adjust current weightings as necessary to better support the asset replacement decision-making process.
	18	Improve the data collection, population and monitoring process for SAP data utilized in the Asset Analytics tool.
	21	Implementation of strategies for the population of absent legacy data (~1 million data fields will be addressed through default populations, derivation, validation, etc.).
	24	Development of data quality assessments and data audits for all Transmission asset classes.
7	28	Planned Maintenance Bundling Enablement: Continue to ensure work bundling efficiency at the Planning level is enabled (i.e. aligning call dates of maintenance plans that impact delivery points) to allow integrated outage scheduling and integrated work execution and minimize outages on same.
10	39	Review vegetation-management program and improve prioritization model to support decision-making. Quarterly review of progress in 2016; Annual review in Q3/4 2016.
11	42	Following the remediation of the Tx data, Planning will enable a project to focus on the Dx data. However, due to resource constraints, both of these initiatives are not able to be implemented simultaneously within the business.
13	46	Assessment of past maintenance expenditures and activities, with a focus on critical factors and contributors to the distribution reliability measure.
	48	Undertake a third-party review of its distribution system plan that will provide unit cost validation for forestry, pole replacement and station refurbishment.
	49	Hydro One's Distribution System Plan is under development and we will be having an independent third party review of such in 2016.
17	68	As part of project closure process, compare our internal construction project costs to industry benchmarks of contracting out similar capital work.

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit

Assessment Type	Assessment Level	Description
Action Item Status	Complete	Evidence exists to demonstrate that the committed actions are complete. All actions fully address Hydro One's response in the Auditor General's Report.
	Substantially Complete	Most actions and control designs are complete, however they are lacking any of the following elements: implementation plan, rollout, approvals, communication, awareness to stakeholders.
	Partially Complete	Actions have been taken on some tasks, however the controls still require further design, stakeholdering, and implementation. Insufficient completeness for Internal Audit to assess control design effectiveness.
	Early Stage	Little to no progress has been made in actions and control designs. Insufficient completeness for Internal Audit to assess control design effectiveness.
	Work In Progress	Tasks that were planned for completion past the audit timeframe – i.e. later than September 30, 2016. The design effectiveness on the management action was not assessed as part of this follow-up audit.
Control Design Effectiveness	Effective	The actions or controls designed fully address the commitments within Hydro One's response in the Auditor General's Report.
	Substantially Effective	The actions or controls designed mostly address the commitments within Hydro One's response in the Auditor General's Report.
	Partially Effective	The review of control designs indicate that only some risks are mitigated.
	Ineffective	The control design is ineffective. Better controls are available to address the commitments within Hydro One's response in the Auditor General's Report.

Hydro One's Enterprise Risk Universe relationship to Auditor General's Recommendations

Below are the relevant enterprise risks related to the Hydro One's risk universe (as communicated at the August Audit Committee) that would be mitigated with appropriate controls based on the Auditor General's Recommendations:

Committee	Risk	Description	Relationship to AG Recommendation	Recommendation Reference
HUMAN RESOURCES COMMITTEE	Human Resources Risk	Uncertain ability to attract, retain, and deploy staff with the required skills, knowledge, and experience.	Indirect	
HEALTH, SAFETY, ENVIRONMENT AND FIRST NATIONS & MÉTIS COMMITTEE	Employee Injuries/ Work Related Absenteeism	Risk of employee injury or illness. Includes major incidents, minor incidents, or lost time due to occupational or non-occupational cause.	Indirect	
	Environment Risk	Uncertain impact of current or past environment practices on Hydro One's business. Includes failure to meet environment improvement goals/requirements.	Indirect	
	Public Safety/Security	Risk of death or injury to members of the public due to interaction with Hydro One's assets, business processes, or products.	Indirect	
AUDIT COMMITTEE	Power System Security Risk (includes NERC, Cyber, Physical)	Risk of unexpected harm to power system assets.	Direct	8
	Information Technology and Data Risk	Risk of unexpected loss, failure or less-than-planned performance of IT infrastructure. Risk of inadequate availability, quality, or control of data/information for decision-making or reporting. Includes data security and	Direct	5, 6, 11

		confidentiality.		
	Market/Economic Conditions	Risks related to changes in financial marketplace (economy, interest rates, etc.) and credit conditions. Includes Hydro One's reputation with investors, and ability to raise capital.	Indirect	
	Financial Risk	Risks associated with inaccurate financial reporting (MD&A, AIF, other financial disclosures), and inadequate/inappropriate financial controls.	Indirect	
	Regulatory Uncertainty	Potential for actions or decisions of regulators (OEB, FERC, NERC, WSIB, etc.) to negatively affect Hydro One.	Direct	4
BOARD OF DIRECTORS	Inadequate or Uncertain Dx Asset Capacity/Configuration	Uncertain ability of our Distribution assets (as-designed and built) to accommodate supply or load customers' needs and regulate power flows on the system.	Indirect	
	Cost/Productivity Uncertainty	Uncertain ability to control internal/operational costs and meet productivity objectives.	Direct	1, 2, 3, 7, 9, 10, 12, 13, 15
	Work Program Accomplishment ("getting the work done")	Risk of inability of our Operations workforce to complete the established/prescribed work program, due to people, process, resource or technology issues and constraints.	Direct	2, 17
	Inadequate or Uncertain Tx Asset Condition	Risk of failure of Transmission assets due to age and condition.	Direct	1, 3, 7, 9,12, 13
	Inadequate or uncertain Dx Asset Condition	Risk of failure of Distribution assets due to age and condition.	Direct	
	Inadequate Tx Asset	Uncertain ability of our Transmission assets (as-designed	Indirect	

	Capacity/Configuration	and built) to accommodate supply or load customers' needs and maintain required control and redundancy.		
	Customer Relationship Uncertainty	Risk of damage to Hydro One's relationship with its customer segments.	Direct	16

School Energy Coalition Interrogatory # 46

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: 3

Interrogatory:

With respect to the AESI, 'Hydro One Network Inc. Distribution System Plan Review':

a) Did Hydro One undertake a RFP process to select AESI to undertake this review? If so, please provide a copy of the RFP. If not, please explain how AESI was selected.

b) Please provide the terms of reference for the review.

c) Please provide a copy of all information AESI reviewed that is not already contained in the pre-filed evidence.

d) [p.4] Please explain what AESI means by "positioning".

e) [p.4] The review states: "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 comments on all these points. In some cases Hydro One did not heed to the comments but explained their rationale and appreciated that they would be of assistance in more thoroughly preparing for interrogatories during the process". Please provide a copy of all the referenced AESI comments and suggestions, as well as Hydro One's responses.

Response:

a) AESI is one of Hydro One's vendors of record for regulatory-related services. This list allows Hydro One to pre-screen qualifications for vendors and, as a result, leads to a more timely and efficient sourcing process when a service requirement arises.

Hydro One sent a Request for Proposal to all its vendors of record asking them to quote a price for the envisioned list of services as well as their qualifications and any other factors that might demonstrate their ability to complete the work. AESI's response was determined to be the most viable and provided the best value among those responses that were received. Especially relevant was the fact that AESI has experience completing distribution system plans for other utilities in Ontario and was well versed in the OEB filing requirements. Hydro One chose AESI to complete the DSP review.

b) Please see Attachment 1.

c) AESI was retained to review the Sections included in the DSP. The review process included the review of partial drafts to allow AESI to understand the material, and where appropriate, point out areas that were deficient. The information considered in this regard concerned (a) draft copies of the DSP and (b) the OEB's filing requirements. AESI's review also involved a number of exchanges with Hydro One staff which were held to clarify and discuss DSP content and possible ways to improve presentation of these materials. AESI also reviewed the final draft and it is that draft upon which they made their final comments. Any information provided to AESI was part of a Section that has been included in the DSP submission.

The information that Hydro One is relying on in this Application is the pre-filed Distribution Plan. AESI's conclusions regarding compliance is now a moot point given that the OEB has set the Application down for hearing and in doing so, has found the content of the Application accords with its filing requirements. Information exchanged between AESI and Hydro One which addressed comments on draft versions of the DSP, and in particular, ways in which presentation of DSP topics (e.g. sentence structure, use of adjectives, pagination, numbering and ordering of paragraphs) could be improved upon are not matters which Hydro One believes are within the scope of the issues identified in this proceeding and therefore declines to provide such information.

d) The use of the word "positioning" in Line 5 on Page 4, was a reference to the fact that Hydro One placed the section related to Customer Engagement in a 'position' near the front of the DSP. AESI asked why it was placed as effectively the third section out of approximately 20 sections in total in the DSP. Hydro One felt that including the customer information near the front of the DSP reflected the importance of that information in the development of the DSP.

e) Please see part (c) above. Hydro One relies on its pre-filed Distribution System Plan in support of the relief sought in this Application. The questions posed do not pertain to this evidence. Whether comments provided by AESI were or were not incorporated into the final version of the DSP is a matter beyond the scope of this proceeding.

PART 3: TERMS OF REFERENCE

1.0 Background

Hydro One Inc. is a holding company with subsidiaries that operate in the business areas of electricity Transmission and Distribution ("T&D"), and telecom services. Hydro One Inc. is wholly owned by the Province of Ontario and our T&D businesses are regulated by the Ontario Energy Board ("OEB" or "the Board"). Our industry, including our company, is governed within the broad legislative framework of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998.*

Hydro One Networks Inc. ("Hydro One") represents the majority of Hydro One Inc. business. As stewards of the Province's electricity grid, our core role is to provide safe, reliable and cost-effective electricity transmission and distribution and to connect clean and renewable sources of generation to the province's electricity grid.

Hydro One Telecom Inc. is a CRTC-registered, non-dominant, facilities-based carrier involved in marketing the excess fibre-optic capacity. We provide broadband telecommunications services in Ontario with connections to Montreal, Buffalo, and Detroit. Building on the expertise and reliability of Hydro One, Hydro One Telecom delivers broadband telecommunications solutions for Carriers, ISP's, commercial customers and the Public Sector.

Hydro One is the largest electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 96.6% of Ontario's transmission capacity based on the revenue approved by the OEB. Based on assets, our transmission system is one of the largest in North America and our distribution system is the largest in Ontario.

The following link can be found and accessed in Part 5 - Attachments and Hyperlinks. In this website, information about Hydro One Inc. and its subsidiaries is available. Website: http://www.hydroone.com/OurCompany/Pages/QuickFacts.aspx

2.0 Hydro One Distribution System Plan (DSP)

The OEB Renewed Regulatory Framework for Electricity Distributors (RRFE) emphasizes the importance of planning as the foundation for rate-setting. The filing requirements for DSPs are provided in Chapter 5 of the OEB's Filing Requirements. In support of its proposed capital investment programs, Hydro One will submit a consolidated stand-alone DSP in its next distribution rate application expected to be filed in Q1 of 2017 for rates for 2018 to 2022 inclusive. The DSP "is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan".

2.1 Deliverables

Hydro One is seeking to secure the services of a qualified third-party to perform a thorough review of its DSP at various stages of its development. The successful proponent will:

- Provide best advice on the structure and format of the stand-alone DSP document to show direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized DSP and corresponding capital and OM&A investment programs;
- Demonstrate expertise and capability in identifying areas of opportunity to meet the requirements of the RRFE and Chapter 5 of the OEB's Filing Requirements regarding DSPs;
- Showcase that the Hydro One business planning process is based on its business values and strategic objectives, which consider the balance of its work programs and associated risks;
- Ensure evidence demonstrates alignment between the proposed investment levels, customer engagement results and asset needs; and
- Identify any inconsistencies throughout the DSP including but not limited to the terminology for the different stages of the investment planning and optimization process.

3.0 SCOPE OF WORK

3.1 Project Requirements

<u>Part A</u>

- Provide recommendations and suggestions on the drafts and final structure, format and evidence contained in the stand-alone DSP as discussed in section 2.1;
- Attend meetings with Hydro One as required;
- Deliver a presentation at a Stakeholder Consultation regarding the direction of Hydro One's DSP (if required);
- Provide periodic reviews of the evidence through development stages; and
- Develop a final report to be submitted to the OEB in the distribution rate application evidence.

<u>Part B</u>

- Participate fully, in cooperation with Hydro One, in the filing, discovery, hearing and argument phases of the OEB review of the distribution unit cost benchmarking studies; and
- Defend the plan, findings and conclusions as an expert witness for Hydro One, as and when required, in a regulatory proceeding through the phases of the regulatory application process as defined by the OEB. This includes the preparation of expert witness testimony and other related evidence as necessary to support methodology and

measures applied and related assumptions on economic parameters, comparable companies, comparison criteria, etc.

3.2 Consultant Requirements

The consultant required for this assignment must:

- Be able to provide all of the services outlined in Section 3.1;
- Have expertise and proven experience in the guidance and review of other larger utility's DSPs;
- Have in-depth knowledge and experience in applying general regulatory principles as they apply to the project scope;
- Have knowledge of specific practices and precedents within the regulated utility industry, especially within the jurisdiction of the Ontario Energy Board;
- Have significant experience in acting as an expert witness at rate hearings in the subject areas covered by this work scope;
- Be able to demonstrate that they have successfully completed similar work for other large clients, on time and on budget;

3.3 Schedule

The schedule for completion of the activities in Section 3.1 is driven by the regulatory requirements for a new rate application, tentatively assumed to be submitted in the first quarter of 2017. The consultant shall base their response to this RFP on meeting the following schedule of major milestones.

1. Review the Draft DSP structure and format	2nd week of April 2016
2. Periodic meetings and reviews	On-going
3. Review the final Draft of the DSP	3rd week of November 2016
4. Stakeholder Consultation Presentation	TBD
5. Deliver the Final Report	End of January 2017
6. Fully participate in the regulatory proceedings	As required

Note: The number of milestones and dates are subject to change as Hydro One deems appropriate.

3.4 Pricing

For Part A
Preparation of the study and report outlined in Part A should be costed and a single lump sum price is to be provided for the study.

For Part B

Please provide individual hourly rates, as appropriate. Expected reimbursable expenses must be pre-approved and in accordance with the Ontario Public Service Travel, Meal & Hospitality Expense Directive.

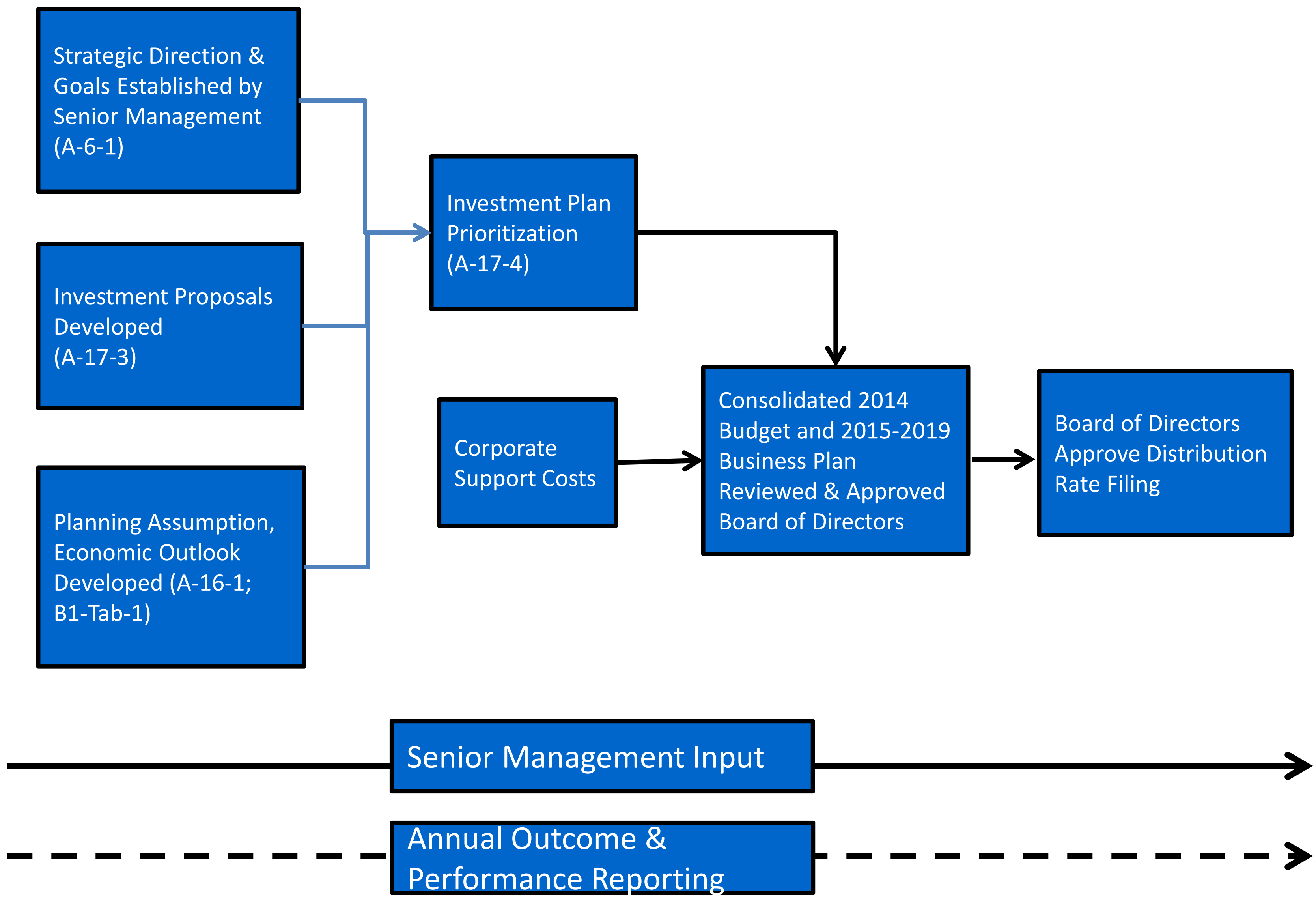
2015-2019 Custom Distribution Rate Application

Distribution System Plan

Paul Brown

Director, Distribution
Asset Management

The Planning Process (A-17-1)



Developing Investment Proposals
(A-17-3)

- **Determine customer needs** through customer satisfaction and transactional research (A-5-1)
- **Collect and analyze system data** during routine maintenance and inspections and technical assessments
- **Assess needs** with a view to mitigating risk associated with failure while maintaining performance and satisfying customer expectations
- **Identify investment alternatives** with emphasis on identifying best value alternatives and bundling opportunities

Selection/Prioritization/Pacing

(A-17-4)

- **Selecting Investments through Asset Risk Assessment**
  - Address customer, system growth and renewable generation needs
  - Renew end-of-life assets to ensure safety and service continuity
  - Maintain Q4 reliability/ improve efficiency
  - Modernize distribution system to add customer value
  - Effectively respond to unplanned system events
- **Pacing/Prioritization/Optimization of Investments**
  - Asset Investment Planning Tool include parameters set by Hydro One planners on a case-by-case basis
  - Managerial consideration of customer needs and program/project risk

hydro one

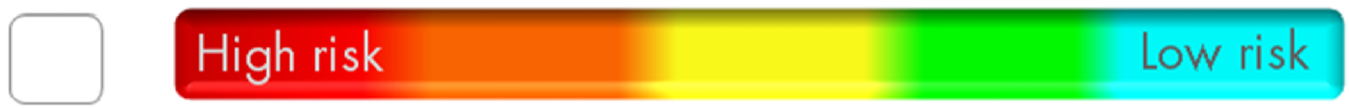
Asset Risk Assessment

(A-17-4)

- Asset Analytics is a tool used by planners in the Asset Risk Assessment process
- Asset data at a glance by feeder/station/class of assets
- Aligning asset groupings to fit Regional Planning Process
- Streamlines the identification of higher risk assets
- Assists in determining the most cost effective remedial action a high risk asset requires

Asset Analytics Risk Factors

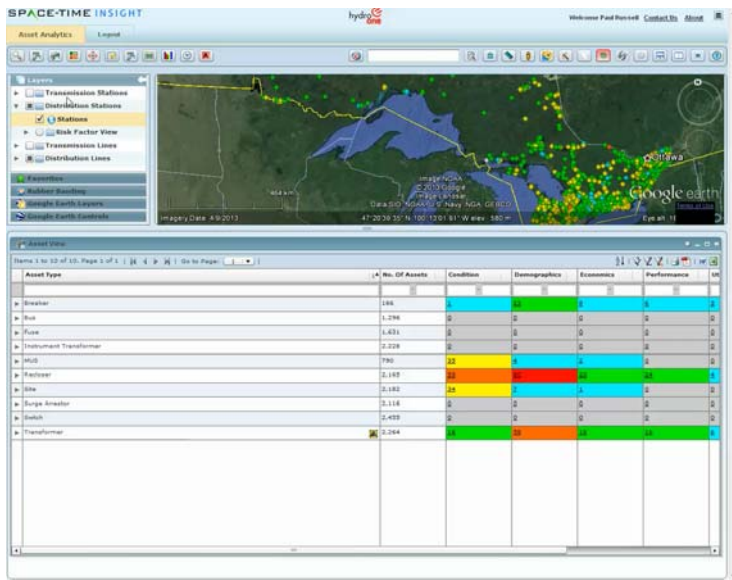
6 risk factors are colour coded on a red to blue scale to give a visual representation of asset risk. Risk factors for a given asset are calculated relative to assets of the same type.



1. **Condition Risk** reflects probability of failure due to the degradation of condition over time.
2. **Demographic Risk** reflects the probability of failure based on a particular make, manufacturer, and/or vintage of an asset.
3. **Economics Risk** reflects the economic evaluation of the ongoing costs to operate an asset.
4. **Performance Risk** reflects the historical performance of an asset.
5. **Utilization Risk** reflects the deterioration rate of assets that are highly utilized.
6. **Criticality Risk** represents the impact that an asset's failure has on the distribution system, specifically, the number, type and size of impacted customers.

Asset Analytics

Asset Analytics Demonstration



Play video

ONTARIO ENERGY BOARD

FILE NO.: **EB-2013-0416**

VOLUME:	**Issues Day**	
DATE:	**May 12, 2014**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Marika Hare	**Member**

Wayne Smith

MR. ROGERS: We will move -- I will introduce the panel starting from your left to the right. First we have Ms. Laura Cooke, who is vice-president, corporate relations with Hydro One. Next to Ms. Cooke is Mr. Mike Winters, who is the senior vice-president, engineering and construction. In the middle of the panel is Mr. Sandy Struthers, chief administration and chief financial officer of the applicant. And to your far right of the panel we have Mr. Wayne Smith, who is senior vice-president of operations.

And the panel does have a slide presentation to make to outline the case, sir, and before beginning on that, can I ask Ms. Lea to give us an exhibit number?

MS. LEA: Yes. Thank you. Because this is a presentation and issues day I think we will distinguish the exhibit number from the rest of the hearing and call this Exhibit PD1, please, and that's letter P, letter D, 1.

EXHIBIT NO. PD1: SLIDE PRESENTATION.

MR. ROGERS: Thank you very much.

Mr. Struthers, I believe you are going to lead off, are you, this morning?

PRESENTATION BY MR. STRUTHERS:

MR. STRUTHERS: That is correct.

So first of all I would like to thank the panel for allowing us to make this presentation to them. This is the fourth presentation the company has made. The first three were in technical conferences.

We are -- as a company have definitely benefited from those discussions and from the input of the intervenor community and also from Board Staff. So we will be filing a series of blue-page updates that have resulted from those discussions.

MR. QUESNELLE: Okay. I just have -- we have it on the screen, sir. Are there hard copies available?

[Ms. Lea passes out hard copies of the presentation]

MR. QUESNELLE: It is just easier to make notes as we go, if that is okay. Great. Thank you very much.

MS. LEA: Thank you.

MR. ROGERS: Does each member have a copy now, a hard copy?

MR. QUESNELLE: We do, yes, thank you.

MR. STRUTHERS: So in front of you is the proposed agenda for this morning's presentation, which will be addressed by myself and my colleagues, and these items include an overview of the strategic direction and value proposition as agreed to by our board of directors, a discussion of the voice of the customer, the challenges and the resultant distribution investment plan, highlights of the application, an overview of the proposed outcome measures, and update of the customer-service recovery process and how we intend to implement the custom application process.

So let me talk about the company's strategic direction. The company, with its new president, spent considerable time last year, being April 2013, with its Board to develop and expand on the strategic direction to

2020, and in doing so we developed with our board the concept that as a company we would provide safe, reliable, and affordable service to our customers today and also tomorrow.

We reaffirmed that we would operate as a commercially driven business and that we would develop a customer-focused culture with reliability, affordability, and services being our drivers.

A number of our board members have questioned what we mean by affordable, particularly as our customers increasingly find rates to be a concern, particularly with rising energy costs.

And affordability to us is driving to keep our costs down using third parties to provide as many services as we can through competitive RFP processes, reducing our full-time head count, and using less expensive resources, moving more of our work force to direct, which is the wrench-turning positions, and away from -- and to the extent possible, reducing indirect work through the use of technologies and investments that we have made, and also through a better work focus.

We recognize our customers want us to control our costs, but they also still want us to provide safe, reliability service to them. And in some cases our customers have clearly indicated to us that they are not happy with our reliability.

Moving on to the next slide, to develop the value proposition we looked at the components that make up safe, reliable and affordable service.

We concluded we needed to keep our portion, the transmission and distribution rate increases, at or less than inflation, recognizing that the main costs, which are increasing the rates related to the capital being in-serviced, higher depreciation expense from increased rate base, and the possibility over the next five years of increased interest rates.

We recognize that if rates were to increase, we needed to improve customer satisfaction with our performance, and also building trust with our customers, a challenge that we have arguably made more difficult for ourselves, particularly with our billing issues.

We also needed to preserve net income. And as an entity we are independent of the government of Ontario; our debt is not backstopped by the government of Ontario.

Investments in our capital program and the repayment of debt as it comes due means that we must go to the debt markets for financing. Annually, we finance between $1 billion and $1.5 billion on the open markets. And behind the banks, BCE and Enbridge, we are the next largest borrower in Canada.

A stable, fair and predictable regulatory environment and ability to earn our rate of return and the ability to preserve net income are needed to ensure our credit ratings.

To that extent, we continue to be under-leveraged, not at the 60 percent debt level but at a 55 percent debt level at the borrowing entity. We intend to keep an A credit rating, as it reduces the cost of our debt to our customers, and our shareholder continues to fund our expansion and equity capital needs by allowing us to retain dividends in the company.

To ensure that we are spending money in the right areas, we have made investments to provide us with full visibility to our assets, their condition and our work programs.

Tools such as asset analytics are allowing us to make targeted investments to minimize the impact of costs to customers and provide us with an effective way to manage programs and investments. We have targeted improving operating efficiencies and cost savings. And our retirement profile will allow us to replace only the positions that we need, and to focus on moving more of our workforce to the program delivery side of our business.

We continue to RFP work programs, to RFP our back office support, to RFP facilities management, and to the extent that we can within the restrictions of our labour contracts.

Our objective is to reduce our full-time headcount and to make greater use of the Hiring Hall and contract labour in obtaining cost efficiencies.

If I can allow Ms. Cooke to speak, please.

MS. COOKE: Thank you. Good morning.

Continuous improvement in the area of customer experience has increasingly become more of a business borrowing that we provide to our customers.

Mr. Smith?

PRESENTATION BY MR. SMITH:

MR. SMITH: Yes. Hello. Ms. Cooke discussed how we survey our customers and determine what they value. We also interact with our customers and through these interactions we understand specific concerns of individual customers.

Our largest customers have account execs in our field managers, and our field managers that run -- that operate the crews in the field also have a dual duty of being account execs for larger customers.

It is through these interactions with customers that we understand specific concerns of customers related to reliability, and that can include areas from interruptions to power quality and how that affects their service and how that affects what they need from us, in terms of reliability.

Our analytical tools provide a comprehensive and accurate assessment of our assets. This is a recent improvement and adds efficiencies to our planning process and also better identifies where we can spend wisely and where we can wisely not spend.

Much of the data on our assets comes from the people completing the work via the reporting.

The crews in the field also have the best understanding of what it takes to complete work, opportunities for work efficiencies, and local challenges like working on bedrock, working in swamps, or working on the property of a seasonal customer.

We don't just rely on the data to optimize the plan. The planners discuss the plans with the -- and the options in the plans with the managers accountable to complete the work.

Through this dialogue we verify the integrity of the plan, and additional opportunities for innovation are identified working between the head-office people and the field managers.

With all investments we know where and how we provide value. This includes exploring better ways to invest and better ways to complete the investments.

Innovations by manufacturers of the assets we install and innovations on how we undertake the work are continuously explored and reflected in the investment plan. These can lower the costs, but they can also improve safety and meet other customer needs.

The large amount of distributed generation, for example, created operating and maintenance requirements that need to be met safely and with as little impact as possible on the cost to the customer.

The investment plan must be achievable, and in a very efficient fashion.

Work often requires equipment outages, which must be coordinated with our load customers and increasingly with distributed generation. Our investment plan also drives our procurement of materials and of contracted services.

Our work force is flexible. In addition to ensuring they can complete the work, we also want to make sure they are completing the work as efficiently as possible. Again, the planners work with the field managers to optimize the execution of the plan.

We set up the plan. The field -- or, excuse me, we set up the plan. The field managers have the opportunity and the flexibility to optimize that work within the year.

In this fashion, reducing costs related to mobilization of work, travel time, and how crews are located can be maximized to the benefit of the customer and also to drive costs down.

This is critical, given our large territory. Also, storms can often disrupt our best of plans, and you must be able to get back under your planned work program as efficiently as possible.

Our plans are reviewed in detail through a process of a series of meetings. This includes a detailed review by the three of us up here, or four of us up here, and a full-day workshop that both Sandy, Mike, and myself attend and basically grill and quiz the planners to make sure the value is there in the investment plan.

These reviews also identify and prioritize opportunities for continuous improvement and establish commitments from our staff for these improvements.

We also identify where past investments can continue to be leveraged or leveraged better to drive more efficiency and drive better service.

Thanks.

I do want to take a few minutes and highlight a couple of areas of investment. These are larger areas of investment, one being O&M and the second one being capital.

The first investment I will highlight is vegetation management. Our strategy around vegetation management is driven by cost, life-cycle cost. We are currently running at about a nine-and-a-half-year average cycle, and we know from our experience in the parts of the province where we've got the cycle down to a six- to eight-year range that the cost of -- the life-cycle cost of managing vegetation comes down considerably.

Our goal is to get to an eight-year cycle on average across the province over the terms of this rate -- of these five years we have in the rate filing.

To do this we have to ramp up the funding of the forestry program, the vegetation management program, both in areas of brush control and tree-trimming.

Through this we will, coming out the end, by 2019 see a substantial decrease in unit costs, and we will see the overall cost to the work program come down to a level that is recurring cost efficiencies that are sustainable for the long run.

Over this period, in addition to the efficiencies that are coming from getting to a more efficient cycle, we are also driving efficiencies in the way we do our work.

We are looking at more mechanical control of brush, selected use of herbicides. We also are using more extensively feller brush bunchers, which are a machine that can go in, cut a tree, and move a tree far more labour-efficiently, and it drives down our labour involvement, it drives down the efficiency with which we can clear trees, and it also implies a safety benefit, and that there's less safety risk for the worker.

We also have recently at the end of last year come to a four-year agreement with our union that does the -- the PWU, that does the -- most of the vegetation management in terms of brush control and tree clearing.

This agreement sets the base amount of regular employees over the four-year period and allows us to do the ramp-up in work using a more cost-effective hiring hall.

So part of the reason we have actually structured this the way we have was for the labour efficiency and to sit down with the union and achieve that labour efficiency over, in this case, the next four years.

Can we go to the next slide?

The wood-pole program is a program that is very much a long-term program, where we have an aging fleet of assets that we need to basically have a sustainable plan to replace those assets in a way that does not push a cost off into the future years that is not achievable.

So we really want to start ramping up the program which we started this past year to a level that minimally meets the long-term needs of the aging asset base.

Driving this program is the intelligence we have in programs like asset analytics, a portion-by-portion analysis of the province, knowing the age of our fleet of wood poles, knowing where the risk is, and knowing where we want to focus on getting those poles replaced.

We also look over the period of the plan of doing it efficiently. So we want to basically plan an investment strategy that uses the work force as efficiently as possible and does it at the lowest cost we can achieve.

To that regard, though, we still have a lot of difficult poles to replace, poles that are in the Canadian Shield, poles that are necessarily higher because they have more lines on them, and we are focusing on a lot of the more difficult poles over this planning period as well.

Our goal is to basically, from a strategic point of view, have a sustainable pole-replacement program that in the future out five, ten, 15 years we do not -- or we're not hit with an abundance or a backlog of poles that would drive up the rates unrealistically at that point in time.

MR. STRUTHERS: Thank you. So this slide provides you with our forecast financial highlights as shown. The comparators shown in the slide is 2011, the last time that we appeared in front of the Ontario Energy Board.

But I want to make it clear that even though we've had OM&A in 2011 of $535 million, that in 2013 our OM&A total comes to $598 million.

During the period of our IRM we have continued to invest both in programs and also in capital. Our capital program increases in 2015, for example, to the same level that we achieved in 2013, but with an emphasis on

ONTARIO ENERGY BOARD

FILE NO.: **EB-2013-0416**

VOLUME: **4**

DATE: **September 12, 2014**

BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Marika Hare	**Member**

DR. ELSAYED: Okay.

MR. BROWN: -- in the distribution arena.

DR. ELSAYED: Thank you.

MR. BROWN: Not to suggest, however, if I can be a little bit more clear -- if, for example, as an outcome of our asset risk assessment process we required an investment at the transmission level, that would be something that would be identified through that process and a request made into the transmission business for added capacity or things of that nature.

DR. ELSAYED: Thank you.

MR. BROWN: Our new software, called the Asset Analytics Tool, collects data from various source systems that is used to identify six risk factors for the various assets and, based on their values, a composite risk score for each asset.

You can see that the six risk factors are described on this slide. Inside the asset analytics graphical views you are going to see a bunch of colours for an asset or group of assets which indicates risk levels.

For example, in respect of economic risks, red indicates either a high magnitude of corrective and emergent repair costs or high replacement costs, while blue indicates relatively low costs.

In respect of criticality risk, red indicates that the asset supplies a relatively high number of customers and/or a heavy or critical load, while blue indicates a low customer count and/or load.

MR. ROGERS: Mr. Brown, just for my benefit, could you just give me a practical example about how one of these would work? I mean, pick any one you would want. Utilization risk, let us say. How would that be applied to a particular set of assets?

MR. BROWN: So using your example of utilization risk, utilization risk actually takes a look at how heavily loaded or how often used a particular asset is, much the same as a car that might sit in the garage and not get used at all is going to have low utilization risk, whereas something that is run on the Formula 1 track is going to have high utilization and require differing levels of maintenance and cost.

MR. ROGERS: Performance risk, for example, on the same type of asset, you -- that's number 4 here -- you look at the historical performance of that equipment to enter the data into this analytical tool? Is that how it works?

MR. BROWN: Yes. Performance risk actually includes how are the assets performing in the system, how many outages have occurred, and so it is linked in with our outage database, and it is linked in with how many trouble calls we may have been having to go to for a particular asset.

So it is trying to determine and rate, if you will, the risk associated with that performance level. When things aren't operating as we want them to, we want to be aware of it, and that is what would turn something towards the high-risk end of the scale.

MR. ROGERS: All right. Thank you very much. Please carry on. I'm sorry to interrupt you.

MR. BROWN: I am actually ready to show you the more interesting graphical part, which is the Asset Analytics demonstration itself. And please stop me if you have a question here. This is a video, and it is hard to rewind, and so just start yelling at me if you want me to stop and talk about a particular area, please.

MR. ROGERS: So if we stop this, you can put it on pause while we have a discussion and then carry on.

MR. BROWN: Yes. Naiyu is going to help me with this one, and we have tried to coordinate ourselves, so please bear with us. This isn't -- bear with us. It is not the most easy piece to sort of keep tabs on, but really, what this is to illustrate for you is how we go about the asset risk assessment process.

And what we've done with this little demonstration --

MR. ROGERS: Before you go any further, once we get -- just getting this teed up. I'm sorry to interrupt you again, but how long have you had this tool available to you?

MR. BROWN: Since 2012.

MR. ROGERS: And you will be asked about this, I suspect, later on, so just while you're getting the mechanics organized here, is this in wide use in the industry throughout North America or unique to Hydro One?

MR. BROWN: This is pretty new. This is something that a lot of folks are coming to Hydro One to see what we've done here. And in fact, we've given presentations on it at Distributech, and we have not seen a lot of tools developed like this in other utilities at this point, and so I think this is a reasonably leading-edge tool for utilities.

I see that a lot of them are going this way and show a lot of interest in how we have sort of taken a risk-based approach to the assets. So...

MR. ROGERS: Thank you, Mr. Brown. It looks to me as though we're ready to go from my screen.

MR. BROWN: I think we are. And --

MR. ROGERS: Please proceed.

MR. BROWN: -- just to sort of tee this up a little bit, we thought it might be very helpful for the Board to take one of the investments that we actually have in our 2015 plan, which is a Wainfleet distribution station refurbishment project.

So I will let you put the assets up on the screen here. As you can see, we use a Google Earth background here to display graphically our key power system assets, and we're able to filter these views to display only our distribution stations. And so that is what you're seeing on the screen.

I am going to draw your attention to the top left corner of the screen. I have now opened up the six risk factors that I previously spoke about: Condition, demographics, economics, performance, utilization, criticality, and a composite risk factor.

The display -- sorry, the condition risk factor is currently selected for distribution stations, and you can see, because it's got the dot next to "condition" in the top left.

The display shows a colour coding that indicates the level of risk factor. And as I described earlier in the presentation, you've now got a brief description of the colours and their meanings. However, generally blue is very low-risk, through to red being very high-risk.

So now I have turned on the composite risk view that considers all of the risk factors collectively. And you can see that the display has changed some of the colours of the stations because, in addition to just condition risk, we are now considering the additional demographics, economics, performance, utilization, and criticality risk factors.

So what we just did now is we selected a button that provided a new view, which is tabular in nature, rather than geographic, for all of the distribution stations.

Currently, this is sorted alphabetically, and as you can see, this tabular format displays the same factors and shows the same colour codes as the geographic display.

So now we're simply sorting the list by the composite score to show the distribution stations with the highest composite risk. As you can seem Wainfleet DS has the highest composite risk score for all of the distribution stations across the province, and we have this as a refurbishment plan for this station in 2005 -- or, sorry,

2015.
MR. ROGERS: Maybe this is apparent to everybody else, but how do you know that?
MR. BROWN: Okay. On the far right, you're going to see a composite risk score column. And I know it is a little fuzzy on the display here, but -- oh, thank you. That is helpful, Naiyu.
So all of the risk factors to the left of composite are all used together to develop a composite risk score, and so the highest number being 59 is telling us that that is the station with the highest risk factor, from a composite perspective.
MR. QUESNELLE: Are these weighted, these conditions, Mr. Brown --
MR. BROWN: Yes, they are.
MR. QUESNELLE: -- in each particular location? Okay.
MR. BROWN: Yes.
MR. QUESNELLE: And it's consistent weighting. It is not a matter of -- if, for instance, two and three have a certain high weight, does that change the weighting of the others, or is there a -- is it just a static weighting?
MR. BROWN: It is a static weighting for all of these stations.
MR. QUESNELLE: Okay.
DR. ELSAYED: I'm not sure if I can read all of the words on the top, but it looks to me -- is the second column the demographics?
MR. BROWN: The second column would be demographics.

DR. ELSAYED: So that seems to be one of the highest risks that you have in all of the stations?

MR. BROWN: Yes.

DR. ELSAYED: And then for the Wainfleet being the top one, the other red one is the one that I cannot read -- oh, utilization.

MR. BROWN: Correct.

DR. ELSAYED: So why is that a high risk factor for that?

MR. BROWN: So the utilization and demographics of this particular station is a heavily loaded station that is quite old, and the condition is nearly red. So when you combine all of these factors -- it is also a very critical station from the perspective that it has a lot of customers attached to it.

And so that's what makes it go up the list and be the highest.

DR. ELSAYED: How do you define utilization again, sorry?

MR. BROWN: Utilization has to do with how heavily loaded the equipment is or how frequent the operations of the equipment have been.

So, for example, a lot of reclosure operations on the breakers or heavily -- heavy loads on the transformer.

DR. ELSAYED: And the criticality column is basically what I would call the consequences of failure?

MR. BROWN: Very well put.

DR. ELSAYED: Okay. Thank you.

MR. BROWN: What happens when things don't operate as designed? How impactive is that to our customers?

DR. ELSAYED: Okay. Thank you.

MR. QUESNELLE: In this particular group of assets, in what column -- or would it be under performance risk? I am thinking of other leading indicators that would typically be used to predict failures, like oil sampling and what have you. Does that feed in as an adjunct to this, or is it under performance?

MR. BROWN: Yes. I am going to come to that in just a minute, and you are going to see how some -- we are going to drill down into a couple of these for the benefit of understanding.

MR. QUESNELLE: Great. Thank you.

MR. BROWN: I just wanted to point out, though, this is the list of or top 20 stations from a risk perspective. And so I just wanted to point out that, you know, two of these have already had a failure this year.

Twelve of the 20 are either in progress this year or they're part of the 2015 to 2019 plan.

One of them is going to be decommissioned as a result of voltage conversion.

Another had an onsite repair completed this year, and so we are going to see whether that repair brings the risk factors down, so we've done -- we've done a repair; we think it is going to work; and take it off the list.

Another two we're currently doing the same thing with in terms of an internal -- we have taken the oil out of the transformer, for example, and we're currently doing an inspection and hopefully a repair, and so we're going to see how that goes. Two --

MS. HARE: Sorry. Sorry, Mr. Brown. How would I know from this chart that two of them had a failure, or is that just reflected in the performance?

MR. BROWN: This chart basically was developed as a -- at a time when we built the initial investment plan. Okay? So I took a snapshot of what the assets look like at that time we built the investment plan. So that's why it is not yesterday's data.

MS. HARE: Okay. So what you're saying is that, after you did this assessment, two of them had a failure?

MR. BROWN: Correct.

MS. HARE: Thank you.

DR. ELSAYED: So are they near the top of this chart? Where are they in the chart?

MR. BROWN: If you can bear with me, I think I can answer that one. Golden Lake, which I think was about sixth the sixth from the top, it had a failure. And Milford DS had a failure, which is the second from the bottom.

DR. ELSAYED: Okay.

MR. ROGERS: Mr. Brown, I assume this databank or whatever you call it -- this chart is kept current, is it? This is just a snapshot in time, but are you currently always updating it for current information?

MR. BROWN: Yes. It is updated on a regular basis, the frequency of which is dependent on the type of information.

So we don't update it every day for all factors, but, for example, we might -- after the annual test results are done for oil sampling, then it would get loaded into our SEP system and be reflected in here.

The performance data would be put in on an annual basis, for example, things like that. So...

MR. QUESNELLE: Just on that last point, Mr. Brown, you had mentioned something was tied to your outage -- not management system necessarily, but your outage data. I would take it that would be -- could be updated more frequently than annually. When you said performance was annual, does that include the outage report as well?

MR. BROWN: If I may, I may have to get back to you on -- what I could provide -- honestly, I am ignorant on this one. I would have to say these would be the frequencies of the various updates. I must confess that I don't know.

MR QUESNELLE: Okay. Thank you.

MR. ROGERS: We can certainly get -- provide that to you, sir, if you'd like.

MR. QUESNELLE: Yes. I am just interested in the automation elements of this, the performance risk, and outage and, you know. But that would be ideal, yes. Thank you. We will take that as an undertaking then.

MS. LEA: Yes, thank you. That would be J4.6.

UNDERTAKING NO. J4.6: TO ADVISE HOW FREQUENTLY OUTAGE REPORT IS UPDATED

MR. QUESNELLE: Thank you.

MR. ROGERS: Okay. Mr. Brown, please carry on.

MR. BROWN: Okay. We're just going to run this a little further here. And I have now explained the Wainfleet DS -- expanded the Wainfleet DS view to show the major components and the risk factors.

You will note some of the fields have not been populated with data at this point. This is because Hydro One currently does not track some of these data points due to the costs to collect data, but we have set the tool up such that if we make a decision to collect the data in the future, we will be able to easily include it into the displays.

With this view, planners can evaluate bundling opportunities. For example, if only the reclosures and insulators are in need of renewal, these can be bundled together. If, additionally, surge arresters should be replaced, it could be done at the same time.

If all of the assets require replacement, a full renewal of the station could be undertaken.

So this gives a bit of a view of what elements. There is a lot of different components in the station that we may want to consider for renewal.

We are now going to look at the most expensive and critical component of the distribution station, and that is the transformer.

And what we're going to do now is we're going to display the data that we have for the distribution station at Wainfleet. And as you can see, all of the characteristics and specifications associated with this unit are on the right-hand side, and planners -- you can run forward, Naiyu -- this is just sort of showing a bit more of the data. Planners use this information when they're considering what the requirements will be, in terms of scoping out a replacement.

So what we're doing now is we are closing the other window and going to select the condition information for the transformer.

As you can see, there are some listed tests and results, and I will draw your attention to the one labelled "DGA" as an example. This is a dissolved gas analysis test of the transformer oil. Oil samples are taken into the laboratory, and they provide a view as to the health of the transformer, much the same as getting a blood test done for a person.

The results are categorized as 1, being very low risk, to 4, being very high risk. As you can see, the Wainfleet DS transformer is at a very high risk for failure, based on DGA results.

So I am going to close this window now, and I am going to open up the demographics window. So as you can see, this one is fairly simple. We've shown here that the expected service life for this transformer is 50 years and the current age of that unit is 61 years. And you can see that on the right column that says "SF value", I believe.

And this is an area where we would also capture some interesting information. If there was a history of a particular type of transformer or model or serial run, we would capture that kind of stuff in the demographics' view.

MR. QUESNELLE: The demographic attributes, are they searchable, in that if you were to detect that a certain type of reclosure was giving you trouble, you would know where that population is throughout?

MR. BROWN: I would say we have that for the major power system assets, but we wouldn't have it for everything. For example, we wouldn't have it to be able to find a surge arrester, for example.

MR. QUESNELLE: Okay.

MR. BROWN: But there are some levels -- there's a level at which it becomes very onerous to collect data associated with those assets. Major stuff, most of it we have.

MR. QUESNELLE: Thank you. So to go back and retrospectively populate it but on a go-forward basis, your processes populate on a going-in data at a much lower level?

MR. BROWN: To be honest, that piece I am not sure.

MR. QUESNELLE: Okay. That's fine.

MR. BROWN: So I am going to close this window now, and I am going to open up a Google Earth view of the station. This is often used by the planners to visually look at the station and the surrounding area. It just takes a minute to come through here. So what we're going to do now is we're going to go down to a street-level view of the Wainfleet DS.

So planners can now look at the size and the condition of the property, the vegetation issues, the design of the station, et cetera.

And in this particular case, it is kind of -- it's noted that there is no spill containment for the transformer. So if the unit was to develop a leak, the oil would not be contained at the site.

We can also take a look at the various types of equipment that are on the structure, get a general idea of what the station layout is. In fact, in this particular case you can even scroll around and see that there is directly opposite to this site a stream that could be contaminated by an oil spill from the transformer.

So it will be very important for us that spill containment be part of the scope of work when we refurbish this particular station.

That's the end of the video, but I just thought that I -- again, this is a tool that is used by the planners to supplement the asset risk assessment process. There is many other considerations that planners will use in the determination of an asset risk assessment. They're going to take a look at things like growth projections for a particular area, they're going to look at key customers that may or may not connect or disconnect from the network.

They're also going to take a look at -- if they're targeting work at Wainfleet, they're also going to take a look at surrounding areas to see where there is opportunities, perhaps, to dovetail work in between of asset bases and types.

So it is not -- the asset analytics is a tool. It delivers information, it delivers great information for our folks. Planners actually do the asset risk assessment themselves, though, based on this information in combination with a bunch of other things.

That's, in essence, my presentation.

MR. ROGERS: I have a few questions, but I invite anyone else to -- now if you like.

Mr. Brown, just while we have this on the screen here, can a planner go in live to get this kind of information? I mean, anytime they want, they can get this up on the screen and look at a station?

MR. BROWN: Yes, absolutely.

MR. ROGERS: You have all of your stations in this.

MR. BROWN: The entire province is in there.

MR. ROGERS: The whole province. Now, before you had this tool -- you've only had it a year or two -- how did you go about -- how is your planning process different now because of this tool you have just shown to us?

MR. BROWN: A lot of the planning, if you think about it, is probably still consistent with the way we used to do business, but what we used to have to do is we used to have to go to a whole bunch of different source systems and a whole bunch of different field -- field knowledge bases, if you will.

So what you've got is an opinion, often, in the past, from a local area expert on the particular assets. So what this has done is, it's really -- it's reduced the burden associated with data collection in order to do an asset risk assessment.

So our planners now spend far more time thinking and strategizing, as opposed to collecting the information, before they can start doing that process.

MR. ROGERS: Previously before you had this tool how would you do it? Would you send people out to do samples of stations to see, or would they -- did you inspect every station in the whole system previously?

MR. BROWN: There was a lot of travelling involved. And not just to the particular asset that we're talking about, but to adjacent areas. So sometimes the larger view wasn't really something that was as readily available as what we have now.

So those bundling opportunities, those abilities to do work in conjunction with other projects, are now much more visible and real for our planners.

So there is a lot of efficiency and time. We've got better ability and wider scope of information. We've got better data just from the fact that we're collecting more of it and we're putting it into our source systems.

So there's -- also, consistency, in terms of how planners view the risk, because we have created these models that turn all of these various things into a risk assessment. And so all of the planners basically do the work the same way here. They're going to find out that it's got the same risk associated with that particular investment.

MR. ROGERS: With the Board's approval I would like to just ask a few more questions, sir, if I could. What I am trying to get at is, previously how did you collect all of this information? Did you send your own people out? Did third parties come in and do samples from which you extrapolated the condition of your assets? How did it work before?

MR. BROWN: I guess it depends on how far back you go. You know, going back a number of years before we were doing plant inspections and so forth, we had to do specific site assessments at a few representative locations and then try and use data that we did have on, for example, age as a proxy to try and spread that information around and get a view of the system condition as a whole.

We don't have to do that anymore. We've got all of the information collected from our own field staff, getting input into our source systems that can be delivered right to our planners.

So there's accuracy that is far surpassing past practices, when we had to use, you know, some of those other engineering-judgment methodologies, if you will.

MR. ROGERS: One last question, if I could. You may be asked this later by others, I don't know, but has there been any third-party assessment of this process, so far as you are aware? And if not, why not?

MR. BROWN: So we haven't had sort of a third party

ONTARIO ENERGY BOARD

FILE NO.: EB-2013-0416

VOLUME: 5

DATE: September 15, 2014

BEFORE:

Ken Quesnelle	Presiding Member
Emad Elsayed	Member
Marika Hare	Member

and interesting, and the demonstration of the asset analytics tool.

Now, I understand that Exhibit A17-4, so Exhibit A, tab 17, schedule 4, talks about how investment alternatives are developed. And on page 3, around line 7, I think, you list the five steps involved in your investment prioritization process. And I think the second of those is develop multiple investment alternatives to incrementally mitigate risks. And the third one, determine and evaluate the cost, benefits, and risks for each level.

I wonder if we can look at the figure on page 6 of this evidence. And this shows that there appear to be three distinct investment funding alternatives which are developed. And these consist of a level of funding and a corresponding level of risk. Have I summarized that correctly?

MR. BROWN: Yes, you have.

MS. LEA: All right. Going to the next page, page 7, the exhibit provides definitions for the different investment funding or risk mitigation alternatives. Do these alternatives relate to aggregate costs and risk mitigation across asset classes or categories, and not to individual assets? Can you help us there?

MR. BROWN: Each of our investments are developed on a program level or a project level. And so it would be done on a project or program level, as opposed to on an asset class level.

MS. LEA: Okay. So when we look at these risks and benefits that are a project or program level, not a risk analysis, as we were looking at in the asset analytics, which is tied to an asset.

MR. BROWN: The asset analytics actually looks at it from a program and project level as well. The groupings of projects and programs, the planners actually use the asset analytics information to develop their programs and to develop their projects, so I would say that they look at it from that perspective as well using the asset analytics tools.

MS. LEA: Okay. So when we look at the definitions, which you've kindly provided on the screen here for each of the vulnerable, intermediate, and asset optimal investment levels, each of the definitions refers to mitigating risk in some way, so if we look at vulnerable, for example, the first line says:

> "This level of achievement is tolerable only for brief periods and exposes the company to possible risk of asset failure."

And each of the definitions corresponds to some degree to some level of asset failure or a degree of mitigation of such failure?

MR. BROWN: That's correct.

MS. LEA: Can we look, please, at Exhibit 17, schedule 4, at page 4 again? And this gives us a table 1 which shows us the 2013 business values and key performance indicators, and there are seven business values listed in the table.

UNDERTAKING NO. J5.9: TO CONFIRM WHETHER OR NOT THAT 24 PERCENT CAPTURES ONE OR TWO CATEGORIES.

MR. ROGERS: So the undertaking really is just to confirm what Mr. Brown has just said after some reflection.

MR. QUESNELLE: Whether or not that 24 --

MR. ROGERS: Yes.

MR. QUESNELLE: -- captures one or two categories.

MR. ROGERS: Yes.

MR. QUESNELLE: Okay.

MR. RUBENSTEIN: I wanted to ask one more thing related to the asset analytic risk factors. There has been discussion obviously about if, you know, there are -- you find more productivity savings, you're going to put it back into sort of investment in the system, and you were asked sort of, what would you do, and you -- like, what's the first item you would do on the list, and we didn't have -- you didn't know exactly at this time.

If the main purpose of the asset analytic risk factors is to prioritize projects, as I understand it, is there no way from what you've been telling me of sort of prioritizing between different projects using those factors?

MR. BROWN: Sorry, I would suggest to you that the asset risk assessment process is to identify the risks that the power system assets -- and the investment prioritization process is where you would trade off investments.

So if you had an opportunity, an efficiency opportunity, where you wanted to reinvest in the network or you wanted to reinvest in something within the organization, I would say the first thing we would look at is we would look at the list of investments and where did the cutoff happen. What was next on the list. Those would be the earliest opportunities to say -- and this again will be a senior management decision around which -- whether we decide to do that, because all business risks are going to have to be taken into view.

Now, we may just merely decide to do more poles. We may just merely decide to do more stations. But those will be senior leadership decisions in accordance with our investment planning priorities.

Could we pick up a few more projects on the list? Absolutely we could, and those will all be things taken into consideration. However, we might also have budgetary considerations around where we are with particular projects, and those will be also considerations in the determination of where we would make those reinvestments.

MR. RUBENSTEIN: So with respect to any sort of reinvestment, the use of the asset analytic risk factors and sort of -- that would be if you say we need to do more stations, you look at sort of the next one on the list, using these factors?

MR. BROWN: Yes.

MR. RUBENSTEIN: All right. If we can turn to page 9 of the compendium. There was some discussion with Ms. Lea about this, and this is essentially the incremental

INTERNAL AUDIT REPORT

Investment Planning Follow-up (IPF)

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
Kevin Mancherjee	Manager, Investment Planning and Process
Additional Recipients	Email Distribution List

Final Report Issued: September 6, 2017
Draft Report Issued: June 30, 2017
Report Number: 2017-14

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

In January 2015, we completed an audit of the Investment Planning process covering the identification of asset needs to the approval and release of investment plans to address those needs. That audit included our assessment of the controls in place to effectively identify, develop, prioritize and select investment plans in support of the Hydro One five-year business plan and the work program. Our final report concluded that the key controls concerning the Investment Planning process needed significant improvement. The final report contained 18 recommendations that resulted in actions being identified by management under 5 subject areas. At that time, management committed to action plans to address our recommendations and mitigate the risks identified within the report. Management has reported all actions as complete through the quarterly tracking of actions.

Objective and Scope:

The primary objective of this follow-up audit was to provide assurance that Hydro One has completed the committed actions and addressed all the audit recommendations and mitigated the associated risks.

Our work included a review of:

- Governance framework (roles, accountabilities and oversight for addressing audit recommendations)
- Completion of committed action items to effectively address the recommendations and risks
- Assessment of design effectiveness and implementation of any new/revised controls
- Communication of progress and completion of committed action plans (to senior management and process stakeholders)

The following table summarizes our assessment of audit action plan status and control design effectiveness.

Assessment Item	Risk (2015)	Action Item Status Assessment[1]	Control Design Assessment	Risk (2017)
1.1 Business Risk Assessment	M	Substantially Complete	Partially Effective	M
1.2 Governance Documents	H	Substantially Complete	Substantially Effective	M
1.3 Operations Group Input	M	Substantially Complete	Substantially Effective	L
1.4 Quality Assurance Program	H	Substantially Complete	Substantially Effective	M
1.5 Training and tracking	M	Complete	Effective	L
1.6 Lessons Learned	M	Substantially Complete	Substantially Effective	L
2.3 Asset Analytics Data	H	Partially Complete	Not Applicable	H
2.4 Power System Data	M	Partially Complete	Not Applicable	M
2.5 Asset Strategies	M	Substantially Complete	Substantially Effective	L[2]
3.1 Optimizable Alternatives	H	Complete	Substantially Effective	L
3.2 Risk Assessment Matrix	M	Substantially Complete	Partially Effective	M[3]
3.4 Unit Price Catalogue	M	Substantially Complete	Substantially Effective	L

[1] The Action Item Status and Control Design Assessment ratings are described in the legend at the end of this Executive Summary.

[2] Although the development of the required asset strategies are still in progress, management has introduced controls to track and monitor their development by May 31, 2018 with assigned accountabilities and periodic review cycles.

[3] Management has recently introduced a new Risk Assessment Matrix for Transmission and Common assets so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium.

4.2 AIP Tool Availability	M	Complete	Effective	L
4.3 AIP Manual Workarounds	L	Partially Complete	Not Applicable	L
4.4 Enterprise Engagement period	H	Complete	Effective	L
4.5 IP Change Log	M	Substantially Complete	Substantially Effective	L
4.6 Re-optimization requirement	M	Complete	Effective	L
5.1 “Projam” Investments	H	Complete	Effective	L

Success Factors:

We noted that the following success factors were in place:

- Management is now providing instructor-led training to planners for the Investment Planning Process and Risk Assessment with support from the Investment Management team providing drop-in sessions and one-on-one assistance to Planners during the Investment Planning cycle.
- Management has significantly increased access to the Asset Investment Planning (AIP) tool for planners to provide their input on the investment plans from a 4 week window to a 6-month window.
- Management has increased the Enterprise Engagement Review period to a 7-8 week timeframe to enable a line-by-line review of the investment plan by the Operations group.
- Management has developed and documented guidelines for optimization of the investment plans and conditions which must be met in order to re-optimize the plan.
- Management has established more robust oversight controls for “Station Centric” asset sustainment investments by managing them as specific projects (with specific scope, time and cost constraints) rather than on-going multi-year programs.

Summary of Key Recommendations:

We have discussed our observations with management throughout this follow-up audit. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of high and medium residual risk impact items:

High Risk:

- Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.

Medium Risk:

- Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions. Incorporate results of other targeted risk workshops into the overall business risk register.
- Review and formalize existing management direction, presently being delivered as part of Investment Planning training presentations, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission existing out-dated governance documents (including draft policies and process documentation).
- Establish and implement appropriate measures and targets for the Investment Planning Scorecard. Track “go to green” action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.
- Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.

- Assess the effectiveness of the recently implemented, simplified risk assessment approach for the transmission assets and develop a plan to implement a similar approach suitable for distribution assets.

Audit Opinion:

Management has made significant progress in addressing the control deficiencies that we identified and documented within the 2015 audit report, however further progress is needed. Based on the specific areas reviewed, **we concluded that control improvements are needed** to effectively identify, develop, prioritize and select investment plans in support of the Hydro One six-year business plan and the work program.

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. In a separate memorandum we have shared with management additional opportunities for improvement that we believe will further strengthen this function. Additional details are available upon request.

Management Response:

Bruno Jesus, Director, Strategy and Integrated Planning

Management agrees with Internal Audit's observations and recommendations and we are committed to complete our associated actions by the completion dates.

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

Observations	Recommendations	Action Plan
1.1 Business Risk Assessment	**Risk**[4] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we noted that a recent and formal business risk assessment for the Planning business unit had not taken place. Subsequent to that audit, a business risk workshop was completed later in 2015 identifying five Investment Plan risks. Four of these risks were discussed in detail with only one risk (related to productivity underachievement) requiring mitigating actions. The fifth risk, related to erosion of customer goodwill, was not fully discussed due to time limitations of the workshop. Management informed us that the mitigating action related to developing accountabilities and plans for productivity underachievement risk was assigned to Finance which has been completed, but has not yet been fully implemented. Management further informed us that a targeted risk workshop specific to the Distribution System Plan was conducted in 2016. The risk workshop reports did not identify risk owners and no documented accountabilities or processes are currently in place to identify, monitor, control or communicate emerging or revised business risks on a periodic basis as per the Enterprise Risk Management (ERM) framework. ***Risk:*** *Lack of identified business risks and mitigating actions could result in an inability to meet the business objectives and goals.*	Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions originally identified in the 2015 Investment Plan Risk Workshop Report. Incorporate results of other risk workshops into an overall Planning business risk register for appropriate tracking by specifying business objectives, risks, risk owners, mitigating actions, and target completion dates.	The requirement to conduct risk assessments on the annual Investment Plan will be added to the overall Investment Planning deliverables each year. Any recommendations/action items resulting from the risk assessment will be added to the Planning Division's tracker for action items (Internal Audit, AEI, etc.) **Completion:** March 31, 2018

[4] Residual Risk levels applied are described in the legend that follows this table.

Observations	Recommendations	Action Plan
1.2 Governance Documents	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that approved policies and directives were out-dated or not being followed while business process models documented in ARIS[5] were incomplete. Since then, a Corporate Operational Policy Development Review process has been documented and used to develop 13 new policies. The older policies are being reviewed, updated or rescinded as part of the Corporate Policy Review project. Management further informed us that a key policy document titled "Asset Investment Planning Risk Assessment Corporate Operational Policy" continues to remain in draft form since 2013 as the Investment Planning Process is currently under review. The process models documented in ARIS on this subject are now recognized as out-dated by management but they have neither been formally decommissioned nor replaced. Management's current approach is to provide required direction through investment planning process training, however this will likely not be effective as only the individuals receiving the training will become aware of management direction while other stakeholders will not be aware of the investment planning process and related requirements. ***Risk:*** *Lack of well-defined, communicated and understood governance documents could lead to inconsistent decision making and poorly defined investment plan.*	Review and formalize existing management direction, presently being delivered as part of Investment Planning training, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission out-dated governance documents (including draft policies and process documentation within ARIS).	Appropriate governance documents (policy, process, procedure, standard or guideline) will be established taking the existing Investment Planning training material into account. All other existing draft documentation that no longer applies will be removed (e.g. ARIS). **Completion:** June 30, 2018.

[5] **AR**chitecture of **In**tegrated information **S**ystem (ARIS) is business process modeling tool used for enterprise wide business process modeling.

Observations	Recommendations	Action Plan
1.3 Quality Assurance Program	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Management had agreed to establish and communicate quality expectations and required metrics for the end-to-end investment planning process based on our recommendation from the audit on this subject in 2015. Subsequent to that audit, Management implemented an Investment Planning Scorecard, Manager Quality Assurance checklist, and Investment Health Report to assist in identifying potential errors and quality issues as they develop and review the investment plans. Although the Investment Planning Process Scorecard and Investment Health Report provide statistical information regarding potential quality issues, there are no realistic targets or expectations of actions required to achieve those targets. Management informed us that quality assurance review feedback is not documented but verbally provided to the planners based on issues observed during the quality reviews. Without comparing the current measures to established targets and related "go to green" plans to ensure that the targets will be met, the effectiveness of the current quality assurance program cannot be fully assessed. ***Risk:*** *Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.*	Establish and implement appropriate measures and targets for the Investment Planning Scorecard (specifically for non-accomplishment related measures such as estimate quality, Potential Need (PN) [6] notifications that are actioned/accepted, etc.). Track "go to green" action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.	Key performance indicators (KPI) for the investment planning process will be developed and incorporated into 2018 scorecards for impacted directors as per the recommendation. **Completion:** December 31, 2017

[6] Potential Need (PN) is an SAP notification that provides visibility to assets in need of replacement or refurbishment. PNs can be entered into SAP by head office or field Operations staff and are reviewed as part of the investment planning process.

Observations	Recommendations	Action Plan
1.4 Asset Analytics (AA)	**Risk[2]** H	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) is a tool available to planners to assess asset needs based on asset condition data collected during routine maintenance, performance history, utilization, age and criticality. Management informed us that Asset Risk Indexes (ARI) from the AA tool are one of many inputs that feed into the development of candidate investments, and that these ARIs are not intended to be used as a replacement for the sound engineering judgment and decisions of the qualified Planning engineers, and is only one step of the broader process which is used in conjunction with physical inspections. In 2016, management held workshops with key stakeholders involved in the Investment Planning Process to review and discuss changes to ARI algorithms, input data and new risk factors. To date, management has not implemented any of the requirements identified in the AA workshops, however plans are underway to address 78 requirements related to two new risk factors and 159 requirements related to enhancements to risk factors by end of 2020. We remain concerned about the data quality from supporting systems (such as SAP) that are used as inputs to Asset Analytics. ***Risk:*** *The absence of well-understood and quality asset information increases the risk of inadequate asset need assessment which can result in diminished confidence in the process involving the AA tool and the potential for less than optimal investment decisions.*	Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.	Plans related to data required for Asset Analytics will be developed and key steps and milestones to address the recommendation will be tracked in the Divisional Scorecard. **Completion:** December 31, 2017

Observations	Recommendations	Action Plan
1.5 Asset Management Tool Enhancements	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) and Asset Investment Planning (AIP) are two key support tools used by planners for which a number of deficiencies were identified during the last audit. We had noted that the load flows, voltages, asset connectivity and statuses related power system historical data required for area supply studies in support of System development projects were unavailable in AA. We had also noted that there were manual workarounds in place to update AIP input data from SAP and other systems (such as Unit Price Catalogue, Project Forecasts, etc.). Since then, Management has developed an Asset Management Tool Integration Roadmap in 2015, identifying 24 enhancement requests and 16 integration requests with other systems. The roadmap shows that the requirement to integrate power system data from NMS & PSDB[7] systems is ranked 22nd out of 24 in priority. A firm implementation schedule for the enhancement and integration requests identified in the roadmap is unavailable. Management informed us that in the absence of further progress, same manual workarounds as those observed in 2015 remain in place. ***Risk:*** *Unavailability of required data in AA & AIP tools may result in incorrect/inconsistent decision making. Manual workarounds as a result of lack of data integration could result in delays and/or poor quality investment plans.*	Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.	Management will review the tool enhancement roadmap, to determine necessary enhancements taking into account cost/benefit with decisions to keep, defer or discard items. **Completion:** June 30, 2018

[7] Network Management System (NMS) and Power System Database (PSDB) are two systems that contain power system historical data.

Observations	Recommendations	Action Plan
1.6 Risk Assessment Matrix	**Risk**[2] M[8]	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that the risk assessment matrix being used to assess baseline and alternative risks for a given investment was being used inconsistently. Subsequent to that audit, management has conducted annual Risk Assessment training to provide specific guidance to planners with examples on how to perform risk assessment using the available risk matrix. A risk calibration session held in 2016 indicated a moderate success in aligning risks across all investments. As a result, management sought the services of an external consultant (McKinsey) in 2017 to review and recommend a simplified approach to consistent risk assessment for the 2017 investment planning cycle. A new simplified risk assessment is now planned for transmission investments in 2017 with plans to use a similar approach for distribution investments starting in 2018 because the Distribution investment plans are presently with the regulator and "frozen" for the current planning cycle. We note that an informal survey of 17 planners indicated that challenges remain related to risk assessments for distribution investments. ***Risk:*** *Inadequate assessment of baseline and alternative-specific risk could result in incorrect risk values being assigned.*	Assess the effectiveness of the recently implemented, simplified risk assessment approach for transmission assets and develop a plan to implement a similar approach suitable for distribution assets.	Management will assess the effectiveness of the current transmission process and develop a plan (relating to risk assessment approach) to improve the distribution process accordingly. **Completion:** June 30, 2018.

[8] A new Risk Assessment Matrix for Transmission and Common assets has been recently introduced so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium

LEGEND: ACTION ITEM STATUS AND CONTROL DESIGN EFFECTIVENESS RATINGS:

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK CLASSIFICATION[2]	Assessment Indication
MEDIUM: The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
HIGH: The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

The third significant change is an increased focus on the hazard tree removal and demand vegetation management programs. This additional funding will allow for Hydro One to ensure high quality and reliable service to customers by being more responsive to site specific customer concerns and to more effectively mitigate emergent safety and reliability concerns.

Through these changes Hydro One is building the foundation of a long-term strategy to regain control of backlogged maintenance and shorten the average maintenance cycle. The required funding for the 2018 test year, along with the spending levels for the bridge and historical years are provided in Table 5.

Table 5: Vegetation Management Sustaining OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Landowner Notification *	9.2	6.6	7.3	6.9	10.1	0.0	10.0	0.0
Line Clearing *	97.9	93.7	82.4	87.4	104.6	0.0	107.3	0.0
Brush Control *	23.9	7.7	31.6	35.0	42.8	0.0	42.8	0.0
Cycle Clearing	0.0	0.0	0.0	0.0	0.0	80.3	0.0	79.9
Tactical Maintenance	0.0	0.0	0.0	0.0	0.0	48.5	0.0	57.4
Demand Vegetation Management	9.5	9.9	7.4	13.0	6.8	10.0	6.9	10.2
Hazard Tree Removal	0.2	0.0	0.3	0.0	0.3	4.0	0.3	2.1
Total	**140.6**	**118.0**	**129.0**	**142.3**	**164.6**	**142.9**	**167.3**	**149.6**

** In 2017, Hydro One has reorganized the structure of the vegetation management program such that the Landowner Notification, Line Clearing, Brush Control programs are now integrated under the new Cycle Clearing and Tactical Maintenance programs.*

The vegetation management forecasts for the bridge and test year reflect the changes in program structure noted above. The overall vegetation management OM&A expenditure for the 2018 test year is an increase of 4.7% relative to the 2017 bridge year forecast. This increase represents the pacing of the vegetation management work programs in line with the long-term strategy to regain control of backlogged maintenance and reduce

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

Date: November 10, 2017

Re: Changes to Forestry Plan - Optimal Cycle Protocol (OCP)

Hydro One has developed a new vegetation management strategy and program called the Optimal Cycle Protocol. This new strategy and program will reduce safety risks, improve reliability, reduce the total program costs, and increase customer satisfaction. The attached Briefing Note and presentation are to update the Board on the transition to the new strategy and program.

Yours sincerely,

Greg Kiraly
Chief Operating Officer

Brad Bowness
VP, Distribution

Darlene Bradley
VP, Planning

BriefingNote

hydro one

Date: November 10, 2017

Presented by: Brad Bowness

Overview:

Hydro One is implementing a new vegetation management strategy called the Optimal Cycle Protocol which will transition the company to an industry leading three year cycle. By 2021, the Optimal Cycle Protocol will improve vegetation management outcomes by: reducing safety risks, improving reliability, improving unit cost, and increasing customer satisfaction.

Investment Details:

Hydro One's distribution vegetation management program has been a key focus of the Ontario Energy Board (OEB), the Auditor General of Ontario and Hydro One's internal audit department, all of which suggested improvements in program planning and execution were required. Industry peer benchmarking has also positioned Hydro One unfavourably on unit costs, reliability and maintenance cycle length.

Hydro One distribution manages about 104,000 right-of-way kilometers to reduce the likelihood of a vegetation outage and to mitigate public safety risk. Vegetation related outages account for about 30% of System Average Interruption Duration Index (SAIDI) based on the three year average and projected to be over 40% by year-end 2017. Hydro One's performance is 4th quartile relative to industry peers. Deferred spending has resulted in maintenance cycles of approximately ten years, which is much longer than industry average, and has been identified as the largest contributor to poor reliability performance.

Working with Clear Path Utility Solutions LLC over the last six months, Hydro One developed a new program called the Optimal Cycle Protocol. This new program will patrol Hydro One's rights-of-ways on a three year cycle, generate defect-based work prescriptions, and correct through trimming and/or removing, trees that can grow into our distribution lines, along with dead, dying, or diseased trees that can fall into our lines. The Optimal Cycle Protocol will help Hydro One gain valuable system information, improve right-of-way asset condition and provide the opportunity to optimize the maintenance approach for each feeder to improve public safety, reduce risk of wildfire and improve system reliability within the current approved budget. This new program allows Hydro One to manage more kilometers of right-of-way with the same budget.

The transition to the Optimal Cycle Protocol started in September 2017 where the program strategy was rolled out to the field and employees were trained on the new work standards. The work from September 2017 to December 2017 is being closely monitored to ensure that the new program approach is achieving the desired objectives. By mid-November100% of the forestry technicians will be trained on the Optimal Cycle protocol and by year end about 2,380 km of tree trimming and removal will be completed according to the new standard. It is expected that by January 1st 2018, a stable and sustainable Optimal Cycle Protocol will be implemented across the Province.

Brad Bowness /November 2, 2017 10:30pm

Privileged and Confidential – Internal Use Only

Key elements of the transition to the Optimal Cycle Protocol include developing:

- Detailed, defect-based data collection
- Defect-based work prescriptions
- Augmented quality assessment/control and project management oversight
- Revised work execution standards
- Cost and productivity assessments
- A revised organizational structure

Benefits:
The transition to the Optimal Cycle Protocol will allow Hydro One to improve operations and investment outcomes. The expected benefits of the Optimal Cycle Protocol include:

- Improved public safety, asset condition and wildfire risk profiles by reducing vegetation grow-in contacts to less than 1% of the utility forest.
- By 2022, we can expect a 40% improvement based on a ten year average and a 58% improvement based on a 2017 year-end projection. (Figure 1)

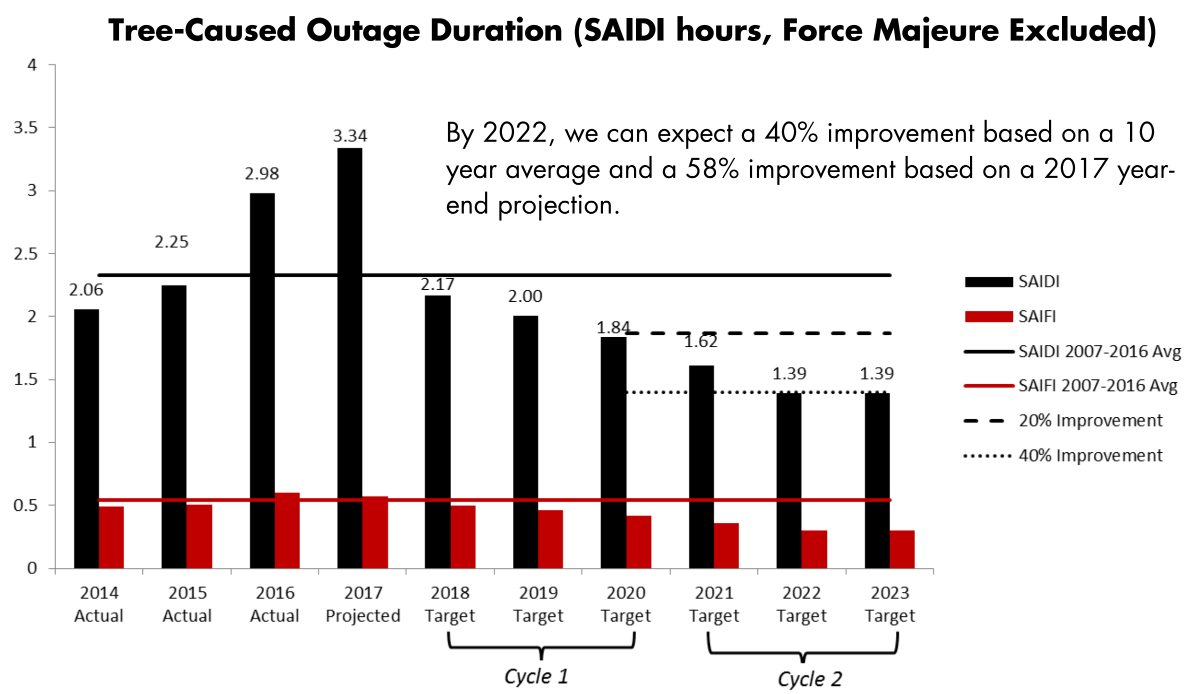


Figure 1 - Impacts of Optimal Cycle Protocol on tree related outage duration

- Reduced program budgets compared to the 2017 OEB approved budget. A further $20M reduction starting in 2023 after the strategy has stabilized. Gradual reduction in trouble calls stabilizing in 2023 and resulting in a $6M to $12M reduction.
- Improved work reporting and standards compliance.
- Improved customer satisfaction and environmental impact due to more frequent right-of-way management.

Estimated Costs:

The Optimal Cycle Protocol will be executed within the proposed five year budget 2018 – 2022 (Table 1). In addition, there is a separate project (currently estimated at $5M capital investment) to deliver a supporting IT tool to manage work more efficiently.

Table 1 - Vegetation Management Budgets

	2015	2016	2017	2018	2019	2020
OEB Approved	$129.0M	$164.6M	$167.3M	N/A	N/A	N/A
OEB Units (as filed)	10,200 km	14,250 km	14,250 km	21,250 km	-	-
HONI Approved Budget	$129.4M	$145.7M*	$138.5M*	-	-	-
HONI Proposed Budget	-	-	-	$149.6M	$150.0M	$152.4M
YE Actual	$118.0M	$142.9M	$129.3M**	N/A	N/A	N/A
Actual Units and Forecast	10,366 km	11,753 km	20,500 km	34,333 km	34,333 km	34,333 km

NOTE: The table above reflects three different strategic approaches with different scopes hence like for like comparison for units may not be applicable.

* Discrepancy between OEB approved and HONI approved is due to redirection to Customer Care and Trouble Calls.

** 2017 Forecast – September

Other Alternatives Considered:

Status Quo or Do nothing Alternative

The do nothing alterative was considered and rejected because continuing with the current vegetation management programs would not yield the desired safety, condition, reliability and cost outcomes within the Business Plan timeframe. Table 2, in the appendix below outlines some of the key differences between the Optimal Cycle Protocol and the current vegetation management strategy.

2. CHANGES THAT DO NOT IMPACT REVENUE REQUIREMENT

2.1 CHANGE IN VEGETATION MANAGEMENT STRATEGY

Historically, Hydro One's approach to routine maintenance was focused on clearing corridors completely and maintaining hazard trees on an eight-year cycle. Deferrals in vegetation management spending has resulted in Hydro One's maintenance cycles to exceed this cycle length.

Pursuant to the OEB's decision in proceeding EB-2013-0416, Hydro One retained CN Utility Consulting to conduct a comprehensive trend analysis of its vegetation management program to show year-over-year comparisons in unit costs and a best practices study similar to a study it conducted for Hydro One in 2009. The report and its findings are provided in Section 1.6 of the Distribution System Plan.

These findings led Hydro One to initiate a review of the vegetation management program to improve its efficiency and impact, as documented in Exhibit C1, Tab1, Schedule 2. Although changes were intended to build the foundation for a long-term strategy intended to shorten the average maintenance cycle, the vegetation management program was still focused on clearing high impact right-of-way corridors completely on a cycle of four to eight years (8,500 km per year), with tactical maintenance on lower impact right-of-ways (4,250km per year) and removal of hazard trees.

Since the Application was filed, Hydro One has continued to further explore opportunities for continuous improvement in vegetation management and innovative approaches working with Clear Path Utility Solutions LLC. ("Clear Path"), an expert in utility vegetation management. A quantitative workload study was conducted by Clear Path which measured Hydro One's maintenance backlog and future workloads and recommended a vegetation management strategy designed to improve the condition and reliability of Hydro One's right-of-ways. Clear Path's study is provided as Attachment 2 to this Exhibit.

Based on Clear Path's recommendations, Hydro One has developed a new vegetation management strategy that maintains corridors on a three-year cycle, focusing on defects rather than completely clearing vegetation in a corridor. This defect-based approach will address vegetation that poses a public safety or reliability threat because it is either (a) growing into or will grow into energized equipment within the three-year maintenance cycle, and/or (b) dead/dying vegetation that will likely cause system interruption and/or equipment damage within the maintenance cycle.

The new vegetation management strategy will consist of three components:

1. **Defect Correction Program**
   The Defect Correction Program is the primary planned work program designed to ensure that one third of Hydro One's distribution network (34,666 km) will be patrolled yearly to identify and correct vegetation defects.

2. **Public Safety and Reliability Program**
   The Public Safety and Reliability Program will provide additional clearing on sections of the distribution system as needed; including such maintenance activities as: responding to customer requests, addressing trouble calls, planned tree pruning and removal, right-of-way widening, right-of-way floor clearing, mitigating emerging forest health issues, herbicide application or other integrated vegetation management treatments.

3. Quality Assurance and Quality Control Program

The Quality Assurance and Quality Control Program will manage and measure the success of its vegetation management investment. In addition to ongoing program management, Hydro One will also undertake work quality assessments, annual treatment effectiveness audits and detailed outage investigations to provide feedback into the continuous improvement process.

This approach to vegetation management will allow Hydro One to eliminate its backlog more quickly and improve the overall condition of its right-of-ways by 2022. Hydro One forecasts the 2018 cost of $149.6 million for vegetation management will not change with the new vegetation management strategy, as Hydro One views the 2018-2022 period as transitional, and Hydro One anticipates incurring transition costs with this new approach. Hydro One is cautiously optimistic that, once the transition is complete, vegetation management costs may decrease by 2023.

This new strategy should also result in improved reliability outcomes by addressing defects that can lead to tree-related outages. Hydro One anticipates addressing approximately 700,000 defects in 2018 over 34,666 kilometres. Historically, Hydro One has measured its units of accomplishments as kilometres actively managed. While kilometres actively managed remain a relevant measure of activity, the success of the vegetation management programs will be further defined by the number of defects completed each year.

The changes to the vegetation management strategy has resulted in a change to the 2018 target in the Distribution OEB Scorecard for “Vegetation Management – Gross Cyclical Cost per km $” presented on page 20 of the updated Distribution Business Plan (Attachment 1).

Hydro One anticipates this new approach will achieve similar benefits but on an accelerated pace due to the increased system coverage enabled by a shorter cycle and a refined scope. The new strategy will quickly reduce the maintenance backlog and enable program optimization. The shorter cycles will improve public safety, reliability, and asset condition providing a more detailed understanding of current and future workloads. Shorter cycles will also reduce customer and environmental impacts due to more frequent, less impactful maintenance.

2.2 UPDATE OF COST ALLOCATION TO NEW ACQUIRED CUSTOMER CLASSES AND COMPARISON OF BILL IMPACTS

As discussed in Section 2.2.3 of Exhibit G1, Tab 3, Schedule 1, Hydro One developed adjustment factors for use in the 2021 Cost Allocation Model ("CAM") to ensure that the costs allocated to the six new acquired residential and general service rate classes (AUR, AUGe, AUGd, AR, AGSe and AGSd) appropriately reflect the cost of serving the customers in these rate classes. Hydro One continues to believe the overall methodology used to develop the adjustment factors is appropriate. However, upon further consideration, Hydro One submits that it is appropriate to also include the cost of distribution stations in its adjustment factor calculations. The proposed change, rationale and results of making this change are described in the following sections.

The updated cost allocation, rates and bill impacts evidence provided below was prepared with reference to Hydro One's 2021 and 2022 revenue requirement as proposed in the Application as of June 2017. The changes to the 2021 and 2022 revenue requirement that will result from the updates discussed in Section 1 of this Exhibit are not captured by the updated evidence provided below. Hydro One notes that the 2021 revenue requirement of $1,684 million shown in Table 2 of this Exhibit is only $4 million (0.2%) higher than the revenue requirement underpinning the revised cost allocation, rates and bill impacts

HYDRO ONE - FORESTRY ASSESSMENT

Final Report

January 16, 2017

Prepared for Hydro One
Stephen Tankersley, Clear Path Utility Solutions, LLC

Confidential

2.2.1 – Contributing Driver – Work Scope

The relationship between maintenance cycle and work scope is critical in achieving program objectives. Maintenance cycle defines the treatment interval and work scope defines actions taken at each interval to achieve desired results. When not aligned, objectives are not likely to be met.

Work scope is outlined in Dx Vegetation Management Standard SIP-045. The standard treatment for cycle work is to clear the entire width of the ROW and address obvious hazard trees. The work is performed using a combination of mechanical clearing equipment and manual tools such as chainsaws and pruners.

Lack of alignment drives a vicious cycle placing one at odds with the other. When the cycle is too long, defects occur, reliability suffers and more work is needed at time of maintenance thus increasing cost per km treated. Not only are eight years of growth being addressed, the work is trying (unsuccessfully) to gain eight more. When cost exceeds budget, extending the cycle is often the result and ultimately performance suffers.

Observations

Current Work Scope is not aligned with the Maintenance Cycle. The Dx Standard of clearing 8 years of anticipated growth is not achievable as demonstrated by system conditions and reliability performance. Significant regrowth appears at about the 3-5-year mark and defects such as tree to conductor encroachments are evident shortly thereafter. Additionally, predicting hazard tree failures over such a long period is not practical, all of which contribute to poor reliability performance and public safety concerns. Hydro One estimates 56% of all trees are in contact with the conductor at the time of work which is an indicator of cycle/scope effectiveness.

***Current Work Scope is not aligned with program objectives*.** Approx. 30% -50% of the work performed has little or no material impact on the key objectives of public safety and system reliability and considered "gold plating" relative to typical industry practices on distribution facilities. This contributes to high maintenance cost which exceeds $10,000 per km treated, limiting the ability to shorten the cycle under reasonable budget constraints.

2.2.2 – Contributing Driver - Labour Cost

Hydro One is the last remaining mid or major utility in North America to exclusively use an in-house work force to perform UVM activities. There are advantages and disadvantages to this resource strategy as discussed further in the document. Cost is among the biggest disadvantages with an in-house workforce.

Labour and equipment typically represents 90% or more of total UVM expense and along with work scope, labour is the highest contributor to program cost. Reducing the labour cost through contracting strategies can have a significant impact on reducing maintenance cycle duration.

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.

UNDERTAKING – JT 3.10

Undertaking

To provide the same table as provided for staff and for each category show the calculations.

Response

Here are the underlying calculations for stations, other station components and vegetation management impacts as reflected in Exhibit DSP Section 2.4.

Stations

Table 52 of DSP Section 2.4, Exhibit B1-1-1 assumes that eliminating all stations in poor condition stations will lead to a 14% improvement in station reliability. The updated assumption is that, by addressing all stations in poor condition, a 9% improvement in station-related reliability will be achieved based on the percentage of station outages that occurred at stations that are in poor condition. Station SAIDI and SAIFI impacts are assumed to be directly proportional to the number of stations that remain in poor condition as shown below.

	Stations in Poor Condition	**Calculation**	**Change in Fleet Condition**	**Reliability Impact**
Current	70	-	-	-
Plan A	0	1 – (0/70)	100%	9%
Plan B	40	1 – (40/70)	43%	4%
Plan C	90	1 – (90/70)	-29%	-3%
Plan B-Modified	70	1 – (70/70)	0%	0%

Other Components

The capital funding available to address other line components is covered under the Planned Component Replacement investment (see Investment Summary Document SR-10). This funding is required to address the replacement of other distribution lines components. The incremental funding available under each scenario relative to Plan B is assumed to address, proportionately, the number of outstanding line equipment defects of approximately 300,000 as shown in the table below.

	Incremental Line Defects Addressed Relative to Plan B (k)	Calculation	Change in # of Defects (Reliability Impact	Reliability Impact Shown (Tables 52-53)
Plan A	25	1 – (275/300)	8.3%	10%
Plan B	0	1 – (300/300)	0%	0%
Plan C	-34	1 – (334/300)	-11.3%	-10%
Plan B-Modified	-5	1 – (305/300)	-1.7%	-5%

Vegetation Management

Plans A, B and B-Modified, reduce the rights of way maintenance on medium or low-priority rights of way by 1,000 kilometers per year. This results in increasing the vegetation backlog by 8% and degrades SAIFI and SAIDI by 1%. These increases are offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 8% (i.e. 9% - 1%).

Plan C would reduce maintenance by an additional 1000 kilometers per year on the medium to low-priority rights of way. This is expected to further increase the backlog maintenance and degrade SAIFI and SAIDI by 5%. This is offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 4% (i.e. 9%-5%).

UNDERTAKING – JT 3.6

Undertaking

To provide the 2017 data in the table at I24-Energy Probe-34.

Response

Table 1 - Historical Urban SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.9	2.0	2.3	2.6	2.2	1.9
Excluding LOS and Including FM	3.4	10.3	2.6	3.4	2.8	2.6
Including LOS and Excluding FM	3.2	2.2	2.8	2.8	2.4	2.4
Including LOS and Including FM	3.8	11.1	3.1	3.5	3.0	3.3

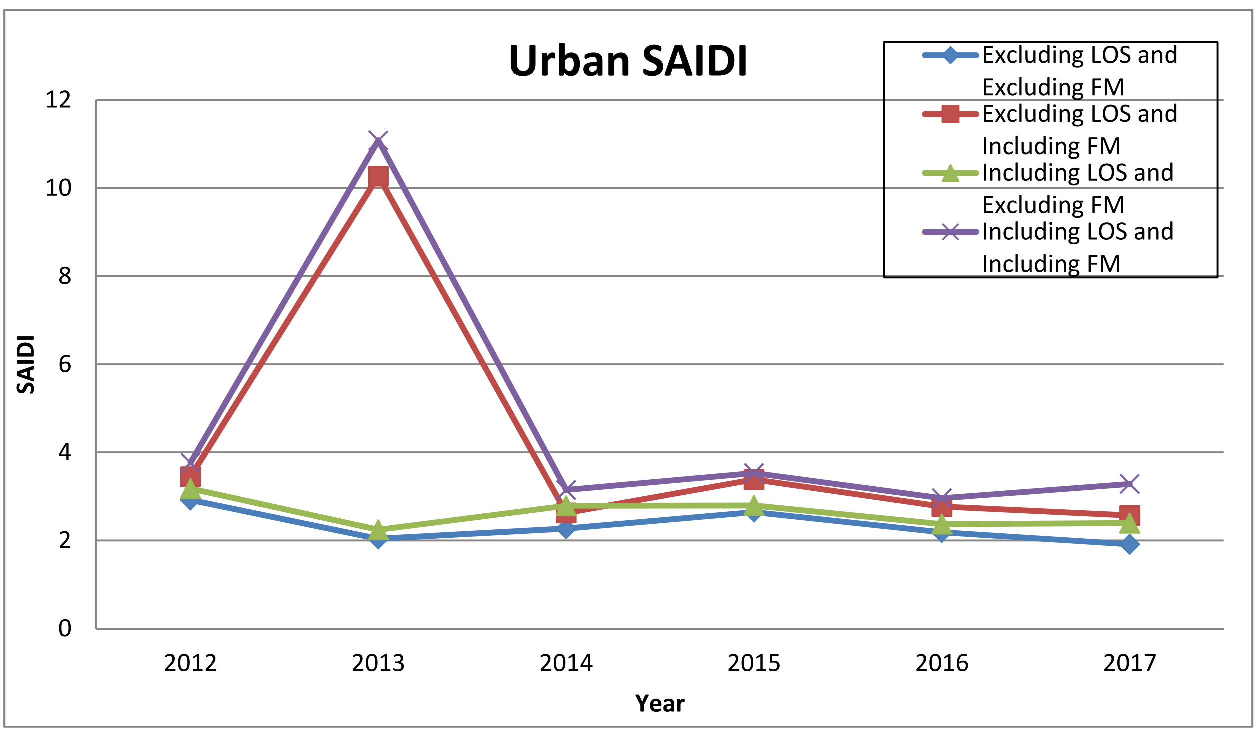


Figure 1 – Chart of Historical Urban SAIDI

Witness: JESUS Bruno

Table 2 - Historical Urban SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	1.3	1.1	1.4	1.1	1.1	1.0
Excluding LOS and Including FM	1.5	2.1	1.4	1.2	1.2	1.1
Including LOS and Excluding FM	1.7	1.6	2.3	1.4	1.6	1.4
Including LOS and Including FM	1.9	2.8	2.3	1.6	1.7	1.6

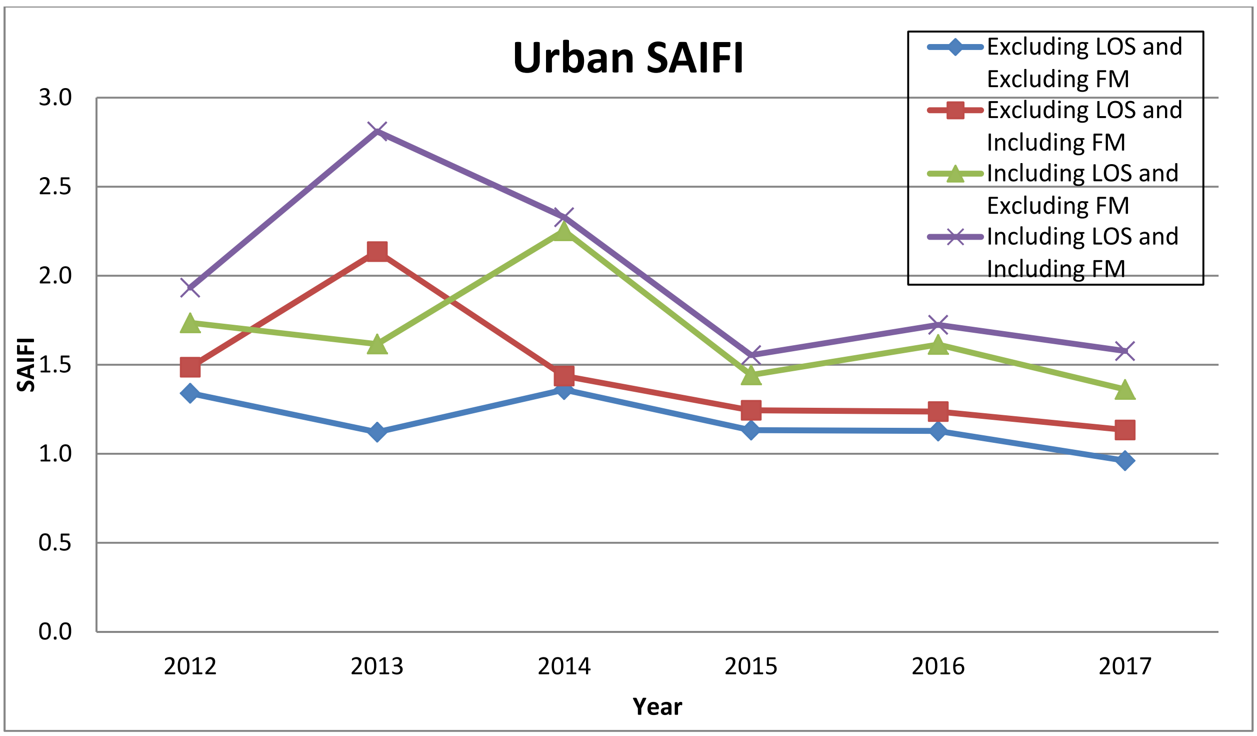


Figure 2 – Chart of Historical Urban SAIFI

Table 3 - Historical Urban CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.2	1.8	1.7	2.3	1.9	2.0
Excluding LOS and Including FM	2.3	4.8	1.8	2.7	2.2	2.3
Including LOS and Excluding FM	1.8	1.4	1.2	1.9	1.5	1.8
Including LOS and Including FM	1.9	3.9	1.4	2.3	1.7	2.1

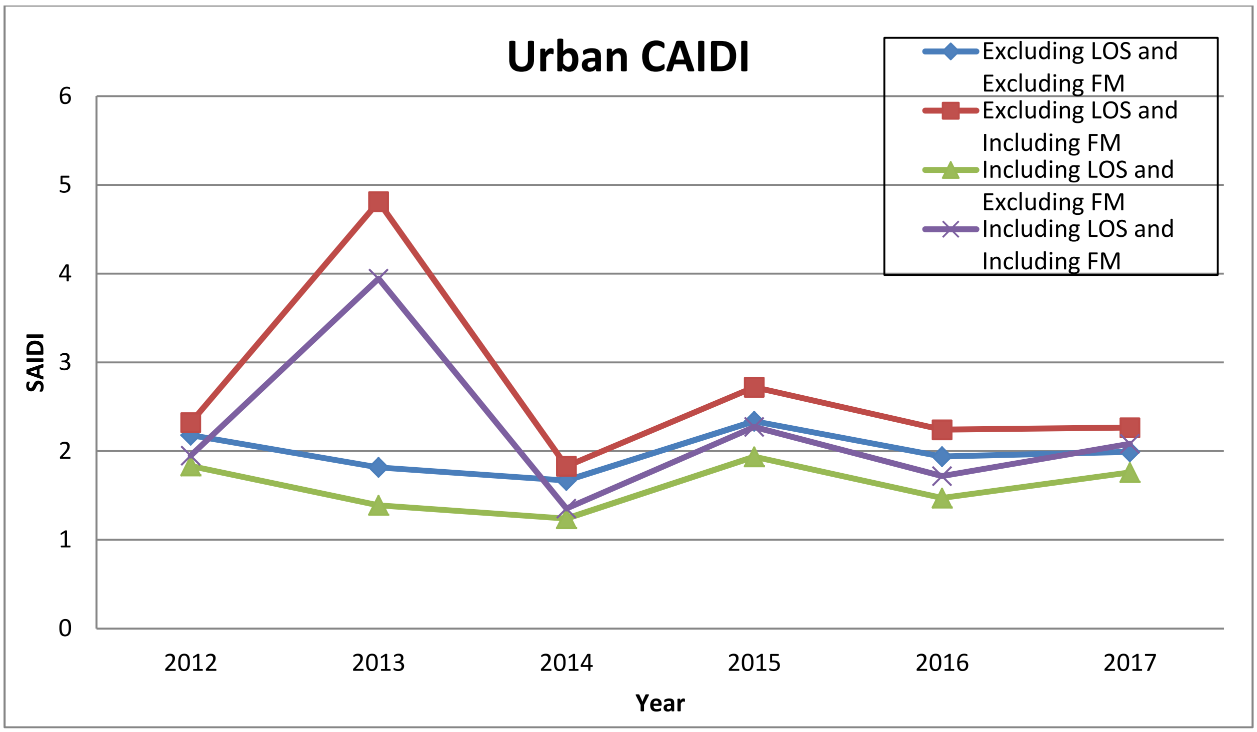


Figure 3 – Chart of Historical Urban CAIDI

Witness: JESUS Bruno

Table 4 - Historical Rural SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	7.7	7.5	8.2	8.4	8.6	8.8
Excluding LOS and Including FM	11.8	29.0	10.3	13.5	14.0	13.5
Including LOS and Excluding FM	8.2	8.1	8.6	9.1	9.1	9.4
Including LOS and Including FM	12.6	30.0	10.9	14.3	14.6	14.4

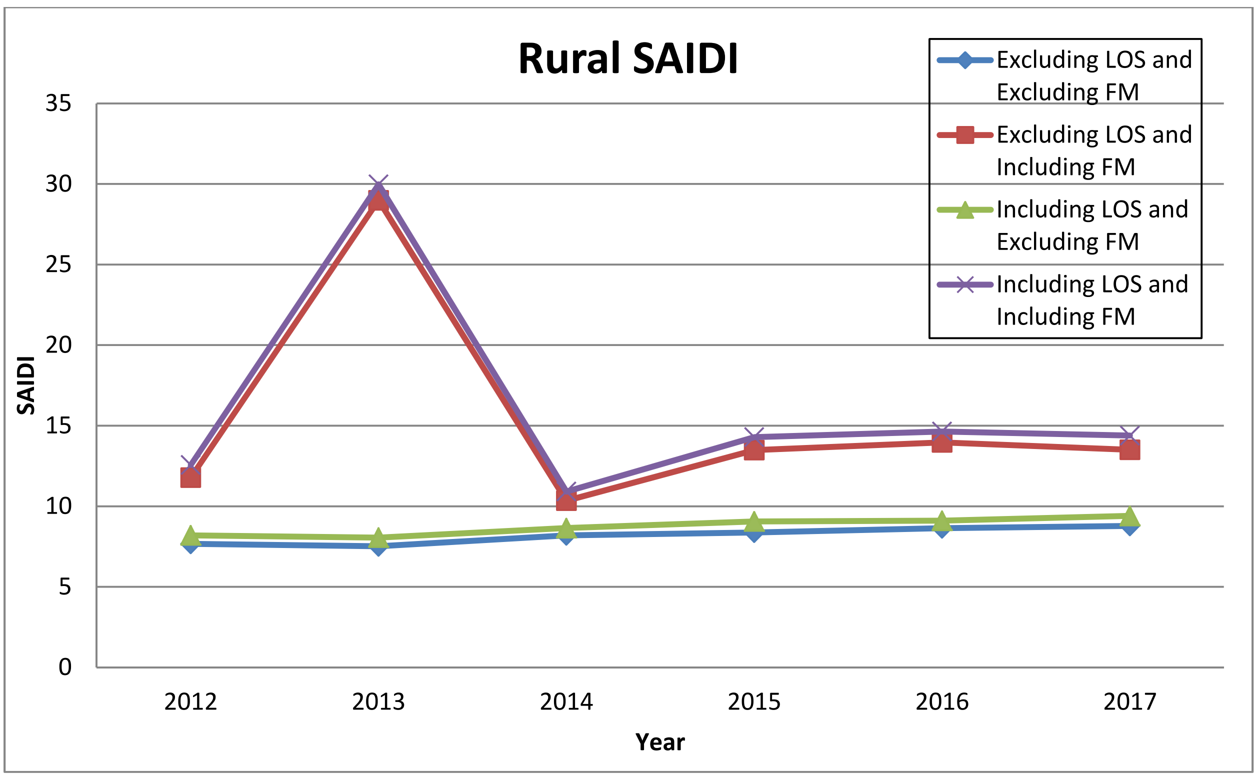


Figure 4 – Chart of Historical Rural SAIDI

Table 5 - Historical Rural SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.8	2.7	2.9	2.8	2.7	2.5
Excluding LOS and Including FM	3.4	4.6	3.1	3.3	3.2	3.2
Including LOS and Excluding FM	3.3	3.0	3.4	3.4	3.1	3.0
Including LOS and Including FM	4.0	4.9	3.7	3.9	3.7	3.7

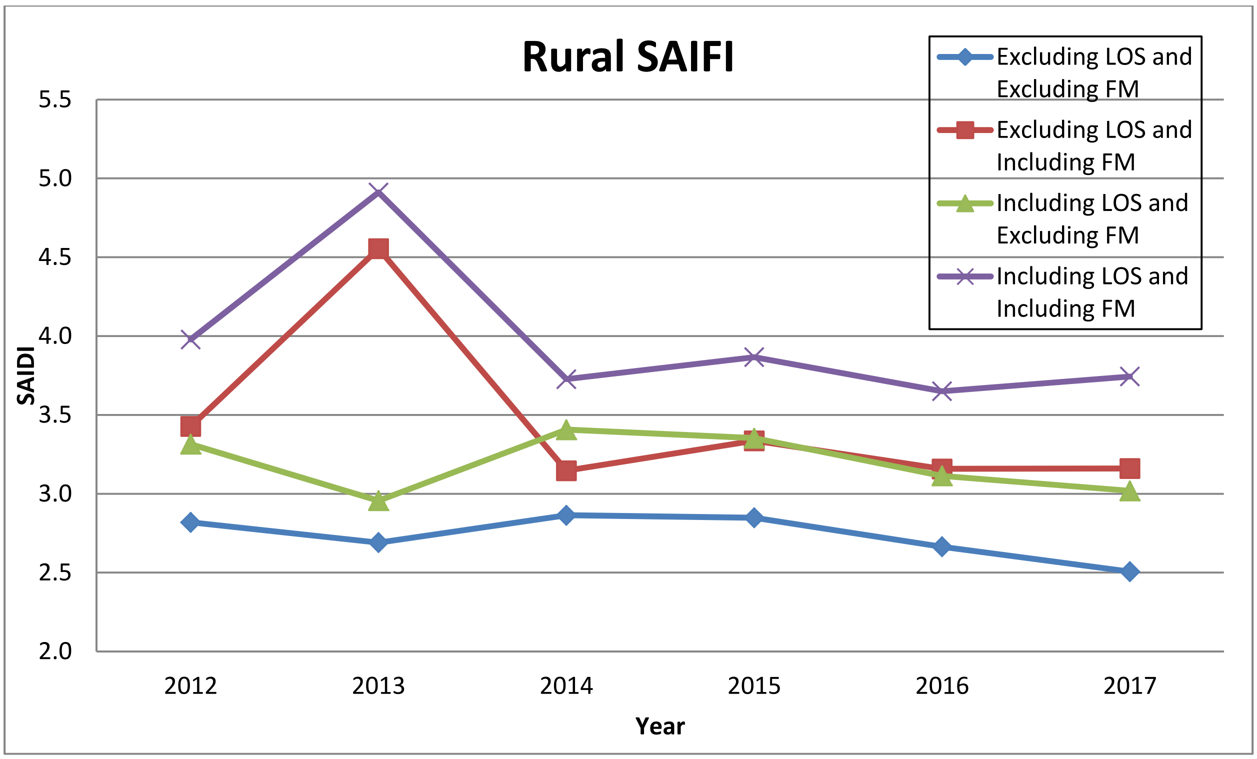


Figure 5 – Chart of Historical Rural SAIFI

Table 6 - Historical Rural CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.7	2.8	2.9	2.9	3.2	3.5
Excluding LOS and Including FM	3.4	6.4	3.3	4.0	4.4	4.3
Including LOS and Excluding FM	2.5	2.7	2.5	2.7	2.9	3.1
Including LOS and Including FM	3.2	6.1	2.9	3.7	4.0	3.8

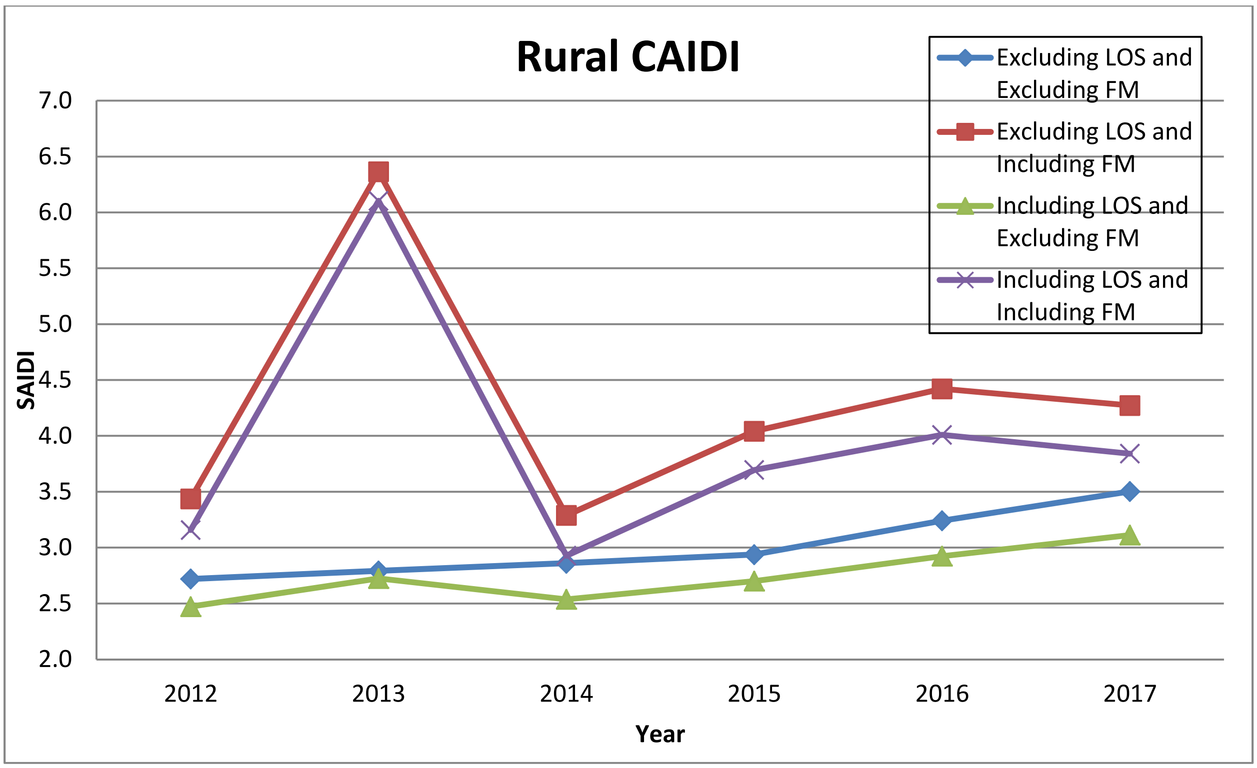


Figure 6 – Chart of Historical Rural CAIDI