Association of Major Power Consumers in Ontario Interrogatory # 7

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 1.1 Page: 8

Preamble: The evidence states "For Large Customers, improving power quality and reducing the number of sustained outages is their top priority. To address this Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue that they are experiencing. Hydro One has increased the funding of reliability enhancement projects to specifically target Large Distribution Accounts and mid-size industrial customers."

Interrogatory:
a) Please provide the number of power quality complaints for each of the years 2012 to 2017.

b) Please provide a copy of the power quality industry standards that Hydro One utilizes.

c) Please provide Hydro One's power quality targets over the test period.

d) Please summarize Hydro One's expected outcomes related to its OM&A and Capital power quality spending.

Response:
a) Please see table below for the annual total number of power quality complaints for all customers over the 2012 to 2017 period.

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Total Number of Power Quality Complaints for All Customers	144	148	167	122	216	171

b) Hydro One utilizes the CSA standards including CAN3-C235-83 Preferred Voltage Levels for AC Systems.

c) There are no specific power quality targets in Hydro One's scorecard, though there is a Large Customer Interruption Frequency metric, as documented on page 20 in Exhibit Q, Tab 1, Schedule 1, Attachment 1. The goal of the power quality program is to address any power quality concerns from Large Distribution Account customers that could impact their operations.

d) The customer power quality program is designed to address the quality of delivered power, which can materially impact customer operations and satisfaction. For further details on Hydro One's power quality programs and expected outcomes, please refer to Section 3.5 in Exhibit C1, Tab 1, Schedule 3 and ISD SS-03 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Association of Major Power Consumers in Ontario Interrogatory # 10

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 1.3

Interrogatory:
a) Page 2 – Please complete the following table:

Ongoing Initiatives	# per year
Annual Surveys	
Transactional surveys	
Focus Groups	

b) Page 3: Please identify the third party that undertakes the Focus Groups?

c) Page 3: On what basis were the Focus Group participants pre-screened?

d) Page 3: How often do Zone Superintendents meet with Large Distribution Accounts?

Response:

a) Hydro One conducts the following:

Ongoing Initiatives	**# per year**
Annual Surveys	10 per year
Transactional Surveys	5 per year
Focus Groups	Hydro One conduced focus groups to support the Customer Engagement process

b) Hydro One's Customer Engagement focus groups (as referenced in Exhibit B1, Tab 1, Schedule 1, Section 1.3.2 (5.2.2 A) Customer Engagement Process were conducted by Ipsos.

Witness: LISTER Warren

c) Per p 37 of Exhibit B1, Tab 1, Schedule 1, Attachment 1, Section 4 R&SB Focus Groups, "Residential participants were recruited using a third-party database and Small Businesses were recruited from Hydro One's customer list. Participants in all sessions were the person in their household or business who is primarily or jointly responsible for dealing with paying utility bills. All groups were a mix of gender, age, working status/business type, income, and education levels. During recruitment, customers were asked their overall perception of Hydro One on a five-point scale. Individuals that selected either end of the scale - very positive or very negative – were screened out to avoid participants with overly strong views one way or the other from dominating the session."

d) The superintendents are to meet with the customer at a minimum of once per year, Additional meetings may be required if there are issues with supply, or if there is Hydro One work that could potentially impact the reliability of supply.

Association of Major Power Consumers in Ontario Interrogatory # 11

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3-A01

Interrogatory:

a) Page 233: Please complete the following Table:

Power Outage Causes	2013 %	2014 %	2015 %	2016 %	2017 %
Trees					
Equipment Failure					
Unconfirmed Causes					
Scheduled Outages					
Loss of Power Supply					
Animal or Vehicle					

b) Certain changes in unit costs were provided to customers. Please provide the change in unit costs between 2015 and 2016 and 2016 and 2017 for brush control, line clearing and wood pole replacement.

Response:

a)

Power Outage Causes	2013	2014	2015	2016	2017
Tree damage	29%	18%	22%	24%	25%
Equipment failure	23%	23%	25%	22%	28%
Unconfirmed causes	20%	17%	18%	17%	12%
Scheduled outageds	15%	18%	17%	17%	12%
Loss of power supply	8%	17%	12%	14%	16%
Animal or vehicle damage	5%	7%	6%	6%	7%

b) For 2015 and 2016 line clearing and brush control unit prices, please refer to Exhibit I-38-SEC-071, part e), Attachment 1. Due to the program changes implemented in 2017 comparable unit prices for line clearing and brush control programs are not available.

Witness: JESUS Bruno

For pole replacement unit prices, please refer to Table 8 in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4 (5.2.3 A and B) Methods and Measures.

Building Owners and Managers Association Toronto Interrogatory # 4

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

Executive Presentation Day Transcript Page: 49-50
Exhibit B/Part B/ISD GP-31 (Prepaid Meters)

Interrogatory:

What customer consultations processes were included in the development of the Distribution System Plan? What were the results? Were customers in favour of the option informed that this would not alter the distribution charge? How will such meters be utilized under time of use scenarios?

Response:

Please see section 1.3 of the DSP (Exhibit B1, Tab 1, Schedule 1). Hydro One’s customer consultation process did not reference pre-paid meters. Additional information on the proposed program can be found in Exhibit I-2-Staff -7.

Building Owners and Managers Association Toronto Interrogatory # 5

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

Ampy – 5188A Single Phase Prepay kWh Meter:
https://www.jwsmartmeters.co.uk/Ampy%205188A

The Ampy 5188A is a single-phase Pre-payment kWh meter. This meter works from a Magnetic card which offers a safe simple and effective solution for "pay as you go" electricity. This eliminates debts that may occur because of non-payments of bills. This technology is proving very effective in the leisure industries.

Interrogatory:

Has Hydro One researched the use of pre-payment meters in other jurisdictions. Which other jurisdictions are using them and for which customer groups? Has Hydro One compared the degree days effective in those jurisdictions to those in Ontario, particularly the degree days in customer locations where the predominance of Hydro One customers with non-payment issues live. Given that even the manufacturer cites the use of pre-payment meters in leisure industries, such as time share accommodation, marinas, campgrounds, why does Hydro One think that these meters address non-payment of bills.

Response:

Hydro One has done some early, preliminary research on the deployment of prepaid meters in other jurisdictions. Prepaid meters have been installed at other utilities with similar climates on an opt-in basis (i.e. voluntary). If Hydro One were to proceed with prepaid meters, they would only be installed at the request of the customer and only after completing field visits.

Building Owners and Managers Association Toronto Interrogatory # 6

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
https://www.theguardian.com/big-energy-debate/2014/sep/11/fuel-poverty-scandal-winter-deaths

In the UK the idea of powering up a water heater with a coin was common; however, the UK has a cause of death called "energy poverty". The social cost of fuel poverty is massive, and growing. In the winter of 2012/13, there were 31,000 extra winter deaths in England and Wales, a rise of 29% on the previous year. Around 30-50% of these deaths can be linked to being cold indoors. And not being able to heat one's home also takes a huge toll on health in general: those in fuel poverty have higher incidences of asthma, bronchitis, heart and lung disease, kidney disease and mental health problems.

Interrogatory:
Has Hydro One researched the health impacts of pre-payment meters?

Response:
Hydro One does not disconnect residential customers in the winter. This policy will continue to apply for customers who may opt into pre-paid meters.

In an effort to assist customers who are struggling to remain current on their bills, Hydro One reviewed all customer-facing collection policies and implemented several changes over the past year. Hydro One's improved collections policies and practices resulted in numerous benefits including a decline in customer disconnections for non-payment.

In 2016, Hydro One launched its Winter Relief Program with the objective to reconnect customers at no charge leading into winter. Over 440 customers were reconnected through this program. Customers were reconnected at no charge with zero down payment.

Building Owners and Managers Association Toronto Interrogatory # 7

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.1 Page: 8

> *A top priority for Large Customers is to improve power quality. To address this, Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue they are experiencing. Furthermore, a capital power quality program has been incorporated into the plan.*

Interrogatory:

Ontario Hydro's Marketing/Energy Management Branch implemented a Power Quality Program in the late 1980s. It was subsequently allocated to Hydro One after the de-merger. Given that improving power quality is listed as a new initiative responding to customer needs identified in customer consultation, please indicate when power quality had ceased to be a program. How many customers had requested such assistance since that date and what advice was given to them?

Response:

Hydro One had a power quality program before the creation of the OM&A program to assist all customers with power quality concerns, including LDA customers, but did not track the number of customers serviced. The existing power quality investigation was funded through the Trouble Calls OM&A program which is discussed in section 3.2.1 of Exhibit C1, Tab 1, and Schedule 2. Capital expenditures identified to be necessary to resolve the power quality concern are funded through the Demand Investments Program, see section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD SS-04 for details. The new program to address power quality complaints differs from the existing programs as it specifically addresses power quality concerns from LDAs. This targeted funding allows Hydro One to better meet the special needs of LDAs identified through the customer engagement process.

Building Owners and Managers Association Toronto Interrogatory # 8

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.1 Page: 8

> *The pole replacement program will be replacing 77,400 poles over the planning period to manage the volume of poles in poor condition.*

Interrogatory:

How many such poles were replaced in the preceding 5 years, the 5 years before that, the five years before that and the five years before that. How many poles were replaced on an annual average basis during the decade prior to the demerger?

Response:

Please refer to interrogatory response Exhibit I-24-AMPCO-25 for details on the pole replacements undertaken in the past five years. Replacement results from over 20 years ago, prior to the existence of Hydro One, are not relevant to this proceeding.

Witness: GARZOUZI Lyla

Building Owners and Managers Association Toronto Interrogatory # 32

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

A-03-01-01 Page: 12

Interrogatory:

a) Please provide the strategic direction from HONI's Board of Directors and executive leadership team to the company, including any written reports, guidelines, budget framework, and the like.

b) p13 – Where is the investment planning process to non-investment alternatives, eg. enhanced maintenance targeted DSM, demand response, are considered?

c) p15 – Please reconfigure the table to the OEB.

d) p16 – Please explain the details of how the existing back-up centre do not meet HONI's standards.

Response:

a) For budget guidance documents, please refer to Exhibit I-3-SEC-001. Please see section 2.1 of the DSP (Exhibit B1, Tab 1, Schedule 1) for the strategic context. There was no written strategic directive provided by HONI's Board of Directors and executive leadership team.

b) Alternatives are assessed at the time of developing a given investment. Non-wires investment alternatives are considered upfront as part of the investment needs assessment (see section 2.1.3 Needs Assessment of the DSP "System Needs/Regional Planning") through the IESO's Regional Planning process, which includes the identification, evaluation and integration of potential wires and non-wires solutions at the regional or sub-regional level. These non-wires solutions are not included in the investment development or investment optimization processes.

c) The "Summary of Distribution Capital Budget" table from page 15 of the December 2016 Distribution Business Plan has been recast using the OEB investment categories below.

Please note that these figures exclude the Acquired Utilities. (For figures integrating the Acquired Utilities as proposed in the Application is presented in Tables 54 and 56 of section 3.2 of the DSP (Exhibit B1, Tab 1, Schedule).)

	2017	**2018**	**2019**	**2020**	**2021***	**2022***
System Access	168	155	158	161	164	168
System Renewal	252	249	319	337	357	445
System Service	67	82	93	86	78	68
General Plant	146	149	187	136	133	137
Total	**634**	**634**	**757**	**719**	**731**	**818**

**The Acquired Utilities are excluded from years 2021 and 2022.*

d) Please see parts (a) and (c) in Exhibit I-30-Staff-174.

Building Owners and Managers Association Toronto Interrogatory # 55

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

A-03-01-04 Page: 5 2015 Data Remediation Project

Interrogatory:

Please provide a status report on the distribution data remediation project. Will it be completed by December 2017? If not, what activities will remain? Had the dispatch of data in different systems been resolved?

Response:

Please refer to interrogatory response Exhibit I-1-BOMA-45 for information on the data governance project related to data remediation. The dispatch of data in different systems still exists but to a lesser extent than before. There are plans to update the Distribution Geographical Information System ("GIS") model, to make the linkage between GIS and SAP more accurate.

Witness: JESUS Bruno

Building Owners and Managers Association Toronto Interrogatory # 78

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

2016 Sector-Wide Consolidated Scorecards of Electricity Distributors Page: 35-36

Interrogatory:

For SAIFI, same question as for SAIDI – MED excluded or included? Why is the target the end of the plan in 2022? Please confirm that the SAIDI initial target of 14.30 is as of 2022, or is it an average over the five years of the plan period. Are there annual targets over the period? If not, why not?

Response:

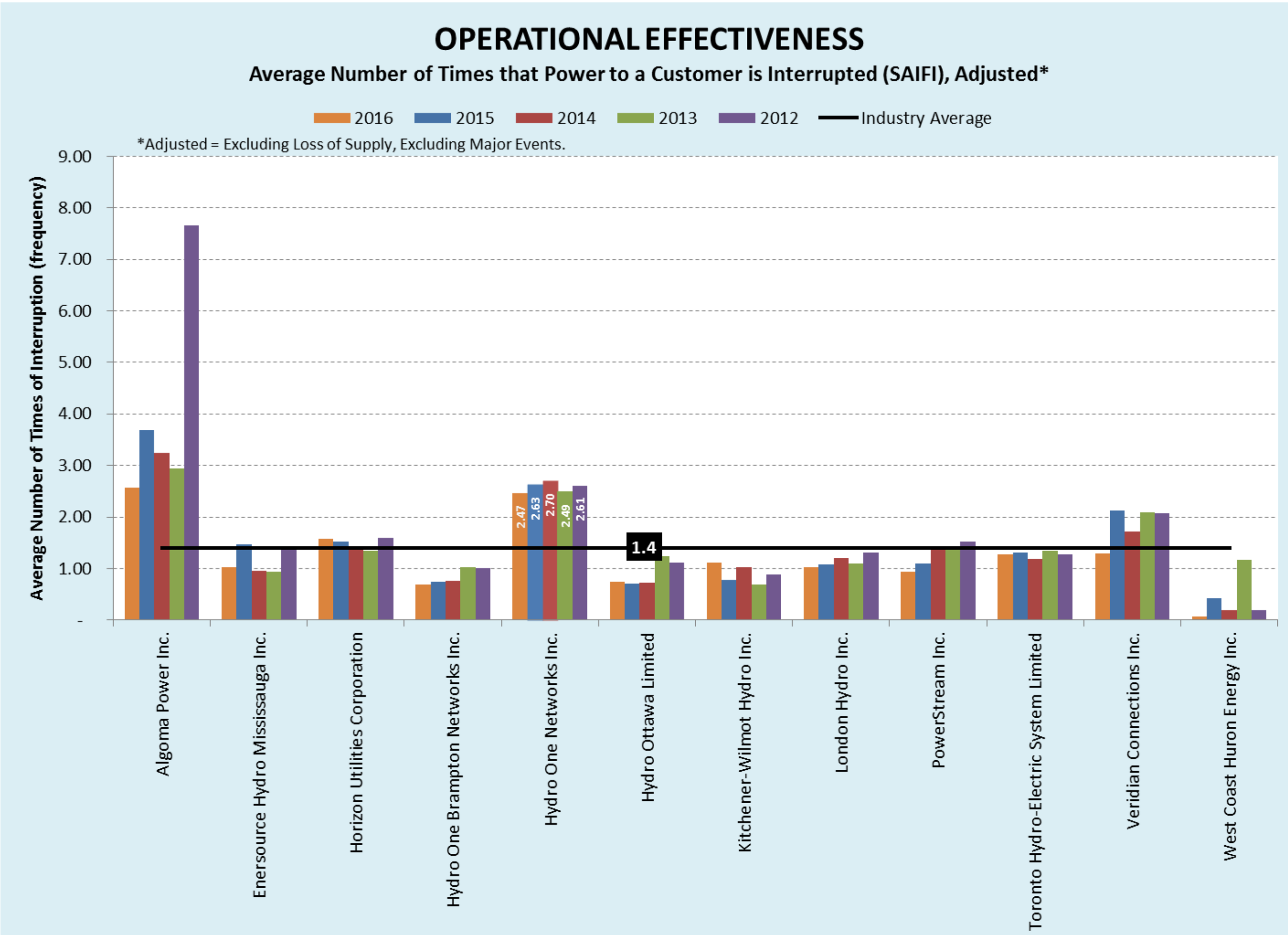
Please refer to Exhibit I-19-BOMA-76.

Using the most recent Electricity Utility Scorecards[1], Hydro One has revised the SAIFI chart below. Excluding Major Events and excluding Loss of Supply, Hydro One's average SAIFI for the 2012-2016 period was 2.58, compared to an industry average of 1.40.

Targets for all measures on the Electricity Distributor Scorecard in Exhibit A, Tab 5, Schedule 1 are shown as the end-targets for 2022. The discussions in the exhibit focus on the performance and the plan to achieve the 2022 targets. Subsequently, annual targets are provided in Exhibit I-18-SEC-029.

The SAIDI target of 14.30 has been revised to exclude Major Events and Loss of Supply, please refer to Exhibit I-19-BOMA-76.

[1] https://www.oeb.ca/utility-performance-and-monitoring/what-are-electricity-utility-scorecards/electricity-utility



The revised forecasted Rate Application Five-Year Target for SAIFI, excluding Major Events and Loss of Supply is 2.0 interruptions. This represents a 22% improvement over the 2012-2016 average of 2.58 interruptions, and about 1.4x above the industry average of 1.4 interruptions.

Hydro One plans on carrying out improvements over the next five years as outlined in Exhibit I-29-VECC-027, part a) through vegetation management improvements, system renewal investments, distribution automation and worst performing feeder improvements and scheduled outage process and practices improvements.

Building Owners and Managers Association Toronto Interrogatory # 126

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

Exhibit B, Tab 1, Schedule 1; DSP 2.6 Page 29

Interrogatory:

a) Please explain why there are two consecutive processes for investment plan approvals, and once the investment plan has gone through selection, optimization, internal corporate review, senior management review, and Board of Directors review, each indicated project must undergo the review set out on p29 of 34.

b) Please explain why this is not, at least in part, duplication of effect.

c) Why, for example, should there be a further cost benefit analysis, reinforced need for investment, and consideration of alternatives, and further cost review? Have not these items been considered in assembling the investment plan consideration and the optimization of the group of investments to be pursued? Please explain fully.

d) Was 2016 an outlier year? If so, what is the average over the last five to ten years on the work?

Response:

a) The individual investment approval described in section 2.1.6.1 of the DSP (page 2388 of 2930) is for Hydro One's projects, a specific body of work that is a one-time event planned for a specific time period. For a project to be released into execution, there must be an individual investment approval. For this purpose, a business case summary (BCS) document is created that provides greater detail on the project's costs, benefits, risks and other considerations. The BCS is also used as the control document for Multilateral Instrument 52-109 (also known as Bill 198) approval authority to meet controls and compliance requirements under securities laws. The investment is then reviewed and approved at the appropriate level within the organization.

b) This is not a duplication of effort as the BCS often has more up-to-date and detailed information than what was available during the investment planning process. Again, the control requirements of Multilateral Instrument 52-109 would also not be met through the investment planning process. Therefore, a document of this nature is required.

c) If the project has not been fully approved (with a BCS) prior to the formation of the current Investment Plan, the information underpinning the values incorporated within the Investment Plan are usually based upon preliminary estimating/engineering information and planner expertise and may not include all relevant field and site conditions and requirements. When the detailed estimating/engineering is completed, the project is reviewed via the BCS process to ensure that the scope, costs and benefits are accurately reflected. Furthermore, some projects are not included in the Investment Plan as they were not known during optimization phase; these projects are typically caused by customer requests and/or other demand or unforeseen work (e.g. equipment replacement advanced from the Investment Plan planned date due to new information from a failed condition test).

d) Hydro One does not understand the question. It does not relate to the evidentiary reference, assuming that the interrogatory is referencing section 2.1 of the DSP as there is no section 2.6. The question also does not indicate for what measure BOMA is asking if Hydro One was an outlier in 2016.

Building Owners and Managers Association Toronto Interrogatory # 129

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3

Interrogatory:

a) How many PCB contaminated transformers does Hydro One Distribution have? What is the proposal made to be replaced each year of the plan, and until 2025, at what annual cost over that period?

b) What is the risk of malfunction?

c) Please provide a copy of, or link to, the government regulation/agreement(s) that requires replacement and establishes the schedule.

d) What percentages of line length replaced on a run to failure basis is on condition assessment in each of the last five years?

e) How many enhanced transformers does Hydro One own and operate? Please describe these additional functions in detail.

f) Please describe how well the SAP maintenance tracking program has worked since installation. What is the annual cost?

g) How are the rural/urban categories defined for maintenance purposes?

Response:

a) The estimated number of distribution lines equipment with PCB contamination is approximately 17,000, the majority of which are transformers. Please refer to interrogatory response Exhibit I-24-Staff-113 for the forecast of distribution lines PCB equipment replacements. The annual cost of these replacements over the planning period is provided in ISD SR-08 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

b) There is no increased risk of malfunction due to the presence of PCBs.

c) The regulations are part of the Canadian Environmental Protection Act, 1999. A summary of the PCB regulations and schedule is found on the Government of Canada website, here: https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/pcb-regulations-frequently-asked-questions.html

d) Hydro One does not replace entire line sections on a run to failure basis.

e) Hydro One is unfamiliar with the term "enhanced transformers" cited in this question. The referenced exhibit (Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3) only refers to Hydro One's distribution station transformers and line transformers.

f) The reference to "SAP maintenance tracking program" is unclear. The SAP system is used to plan and execute maintenance activities; as well as store data that is collected as part of the maintenance activities.

g) For the purposes of maintenance planning, Hydro One uses the definitions of "rural" and "urban" set out on page 2 in Appendix C of the Distribution System Code.

Building Owners and Managers Association Toronto Interrogatory # 130

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 2.3 Page: 8

Interrogatory:
What is the function of the under-load tap-changer?

Response:
Under-load tap changers (also referred to as on-load tap changers in the power industry) are components of power transformers which are used to automatically regulate and maintain the output voltage.

Building Owners and Managers Association Toronto Interrogatory # 132

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 11

Interrogatory:

What percentage of the twenty-three percent of distribution station transformers that are beyond fifty years old, and any additional transformers in the group of 280 distribution transformers deemed to be of high risk?

Response:

Of the 23% (277) distribution station transformers that are beyond fifty years old, 27% (74) are identified as high risk.

Building Owners and Managers Association Toronto Interrogatory # 133

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 15

Interrogatory:

a) What are the criteria, threshold for the various dissolved gas, moisture, and what tests, are used to determine whether a transformer is high risk?
b) What does the high risk category mean, in quantitative terms?
c) How many of the transformers that appear on both lists over fifty, and high risk, are among the number of transformers which HONI plans to (a) replace; (b) repair or refurbish, over the next five years?
d) How many transformers in total does HONI intend to replace over the next five years?

Response:

a) Please refer to interrogatory response Exhibit I-24-Staff-105 part (a). Although this question was focused on transformers subject to imminent failure, the same testing methodology applies to determine whether a transformer is high risk.

b) Transformers identified as high risk are those which have a high probability of failure, relative to the transformer population, based on their condition. If not replaced, these transformers are expected to fail within the five year planning period.

c) Hydro One plans to replace 24 transformers that are both high risk and over 50 years old over the next 5 years. For the remaining transformers that are both high risk and over 50 years old, Hydro One will continue to monitor their condition through annual oil sampling and visual inspections. These transformers will be considered for repair work on a case-by-case basis if the estimated repair costs are not excessive. If failure is identified as imminent based on increasing gas levels or moisture in oil, then these transformers will be removed from service and replaced with a spare transformer under the Distribution Stations Demand Capital Program (ISD SR-01 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8).

d) Please refer to interrogatory response Exhibit I-24-AMPCO-25.

Building Owners and Managers Association Toronto Interrogatory # 134

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 12

"Total failures have gone down on the system since 2013".

Interrogatory:

What has cost the increase of failures from seven to twelve from 2014 to 2016? Why did transformers fail?

Response:

As the transformer population continues to age, and with the number of planned replacements not keeping pace with the aging demographics, it is expected that the number of transformer failures will increase.

Hydro One continues to sample transformers annually to monitor the internal condition of transformers. Transformers with unstable DGA test results and high moisture in oil will be forced out of service to avoid major failures resulting in customer interruptions. However, not all transformer failures are avoidable. For example, transformers with aged insulation can fail during lightning storms. Other transformers with known high DGA test results can fail prior to planned replacement projects. For cause of failure of station transformers, please refer to interrogatory response Exhibit I-25-Staff-156 part (a).

Building Owners and Managers Association Toronto Interrogatory # 135

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 14

Interrogatory:

Please demonstrate, graphically, the influence of criticality in selecting transformer replacements for each of the five years. Please provide details of criticality for each transformer replaced.

Response:

Criticality is one factor in the asset risk assessment which is used in the selection of replacement candidates for station transformers. Criticality represents 20% of a station's composite score. Below is the criticality for each station slated with a transformer replacement under the Distribution Station Refurbishments (SR-06) in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Year	Station Name	Station Criticality Score
2018	Blenheim DS	17
	Duff DS	14
	Gorrie DS	40
	Haliburton DS	44
	Joyceville DS	32
	Meaford Vincent DS	29
	Sowerby DS	16
	Wainfleet DS	5
2019	Birch Island DS	21
	Brigden DS	26
	Chatham Raleigh DS	34
	Dack DS	23
	Grand Valley DS #2	10
	Hawley DS	31
	Ostrander DS	20
	Owen Sound DS #2	34
	Shedden DS	8

Year	Station Name	Station Criticality Score
	Stratford DS	7
	Stratford East Hope DS	12
	Troy DS	28
	Ufford DS	18
	Waupoos DS	35
	Whitedog DS	25
2020	Aspdin DS	88
	Carleton Place Edmund DS	13
	Cobalt DS	47
	Colpoys Bay DS	91
	Island Grove DS	13
	Kenora DS	54
	Millington DS	41
	Oil Springs DS	23
	Nottawaga DS	39
	Reid Corners DS	23
	Tara DS #2	16
	Washago DS	41
	Williamstown RS	1
	Woodland Beach DS	68
	Wroxeter DS	20
2021	Aberdeen DS	86
	Bothwell Corners DS	14
	Cedar Mills DS	84
	Constance DS	67
	Crown Hill DS	35
	Dwight DS	51
	Emsdale DS	36
	Elmvale DS	17
	Emo DS	88
	Ferndale DS	87
	Harriston DS #2	28
	Keswick DS	90
	Lake Vernon DS	35
	Milverton DS #2	18
	Oxmead DS	76
	Willow Beach DS	46
	Wolsey Lake DS	15

Year	**Station Name**	**Station Criticality Score**
2022	Belleville DS #2	26
	Blackstock DS	56
	Brunelle DS	11
	Chemung DS	21
	Coboconk DS	80
	East Luther DS	1
	Horning Mills DS	16
	Listowel Davidson DS	37
	Madoc DS #2	100
	Pinestone DS	36
	Pleasant Point DS	70
	Precious Corners DS	23
	Rutherglen DS	24
	Schreiber Winnipeg DS	39
	Shelburne Andrew DS	23
	Tory Hill DS	49
	West Lorne DS	95
	Woodville DS	70

Building Owners and Managers Association Toronto Interrogatory # 136

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

B1-01-01 Section 2.3 Page: 15

Interrogatory:

a) What is the strategy for upgrading breakers? Are electronic reclosers the same as vacuum reclosers? If not, please describe the differences.

b) What are the costs of a typical recloser, or breaker? What is the range?

Response:

a) When a station with breakers is planned for refurbishment, the breakers will be replaced with reclosers as part of the refurbishment project; as documented in the asset strategy summary on page 1 of Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.

Electronic refers to the control of the recloser. A recloser can be electronically controlled or hydraulically controlled. Whereas, vacuum refers to the interrupting medium. A recloser can use a vacuum chamber to interrupt current or an oil filled chamber.

b) The material cost for a recloser ranges from approximately $2,000 to $30,000. The total cost to install a recloser can vary based on many factors – the most important factor being the modifications to the station structure required to install the new recloser. As noted in part (a) when breakers are planned for refurbishment, the breaker is replaced with a recloser. Therefore Hydro One Distribution does not have current information on the costs of a typical breaker.

Building Owners and Managers Association Toronto Interrogatory # 137

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 18

Interrogatory:

a) How many breakers and reclosers (separate numbers) do you plan to replace over the five year period? How many breakers now have more than fifty years of service?

b) How does the SAP system plan integrate actual physical maintenance?

Response:

a) Hydro One plans to replace a total of 351 reclosers and 7 breakers over the 5 year period based on investments under SR-05, SR-06, SR-13 and SS-02 as documented in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Hydro One currently has 44 breakers that have been in-service for more than 50 years.

b) During the station visual inspection, defects and operation counts are added to the SAP system. Based on this information, maintenance work is scheduled.

Witness: GARZOUZI Lyla

Building Owners and Managers Association Toronto Interrogatory # 138

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 12

Interrogatory:

a) What percentage of failed station switches are repairable? Please provide data over the last five years. What are average repair costs relative to replacement costs? How long will switch last?

b) Please confirm that HONI plans to buy nine new MUS – Same question for each of the asset categories.

c) Why is the fleet being increased from thirty to thirty-three over the plan? What is the need?

Response:

a) Approximately 85% of failed station switches are repairable.

	2012	**2013**	**2014**	**2015**	**2016**
Switches Repaired	56	48	56	96	87
Switches Replaced[1]	10	8	10	17	16
Total	**66**	**56**	**66**	**113**	**103**
Percentage of switches that are repairable	**85%**	**86%**	**85%**	**85%**	**84%**

The average switch repair cost is $5,000 and the average switch replacement cost is approximately $57,000. Hydro One's expected service life for station switches is 50 years.

b) Confirmed. Hydro One plans to buy nine new MUSs over the five year plan; as described in ISD SR-02 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

c) Please refer to ISD SR-02 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 for the need to increase the MUS fleet.

[1] *Based on the switches replaced under the distribution station planned component replacement program (SR-04).*

Building Owners and Managers Association Toronto Interrogatory # 139

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 2.3 Page: 26

Interrogatory:

a) Why do the MUS transformers have a shorter useful life (forty years) than other transformers? How many are more than fifty years old?

b) What is the replacement schedule for the five MUS over the plan period?

c) How many of the five replacements from TFS are in the high risk category? If any are not in that category, please explain.

Response:

a) Please refer to interrogatory response Exhibit I-24-Staff-109 part (b) for an explanation on the useful life of MUS transformers. As per Figure 24 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3; eight MUS transformers are more than fifty years old.

b) As documented in ISD SR-02 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8; six MUSs are scheduled to be replaced over the planned period. Please refer to interrogatory response Exhibit I-29-Staff-171 parts (a) and (b) for the replacement schedule for these MUSs.

c) Two of the six MUS transformers (MUS 35 and MUS 26) have failed. The other four MUSs which are to be replaced (MUS 24, MUS 8, MUS 28 and MUS 30) are all in the high risk category.

Witness: GARZOUZI Lyla

Energy Probe Research Foundation Interrogatory # 31

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3

Interrogatory:

Please list ten most significant changes that Hydro One has made to the DSP as a result of consultations with its customers and provide detail explanations.

Response:

The most significant impact that the formal IPSOS customer consultation had on the DSP was the process that led to the creation of Plan B-Modified. The formal customer consultation results informed Hydro One's planning process and the various plan options that were presented to its Board of Directors. The process is described in detail in Section 2.1 and 2.4 of the DSP (Exhibit B1, Tab 1, Schedule 1) and Exhibit I-24-SEC-36.

In the formal consultation process, Customers were not presented with portfolios of specifically identified investments to comment on. (Please see part (b) of Exhibit I-23-Staff-79.) Therefore, they did not comment on whether they wanted a specific investment in or out of a plan or somehow modified.

Below is a list of examples of investments reflected in this Application that further customers' needs and preferences cost effectively.

1. A restructured vegetation management plan should reduce the impact of vegetation caused outages by 20-40% over the next five years. This will ultimately lead to lower program and trouble call related costs after the second vegetation cycle.

2. Distribution modernization investments that enable system wide automation and incorporate emerging technologies to minimize the impact of outages and restore power more quickly through the installation of remotely controlled sectionalizing devices and fault locating sensors.

3. A worst performing feeder program will address feeder performance outliers to improve reliability for customers affected by poor performance as detailed in ISD SS-06 (DSP Section 3.8, see page 2687 of 2930).

4. More extensive power quality monitoring that leverage customer smart meters should improve power quality.

5. Numerous productivity enhancements will ultimately result in lower costs for customers. (Additional detail on these initiatives is provided in Section 1.5 of the DSP, page 1965 of 2930.)

6. Leveraged innovation and new technologies in the distributed energy resource (DER) space (i.e. energy storage, micro grids, electric vehicles) sill provide cost effective solutions and increased choice for the benefit of customers.

Ontario Sustainable Energy Association Interrogatory # 16

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3

Interrogatory:

a) What was the cost of the customer consultation process in total?
   What were the costs attributed to each of Mercer and IPSOS?

Response:

a) The total cost of the Distribution Customer Engagement process was $395,000, largely Ipsos expenses. Mercer had no involvement in the customer engagement activities.

School Energy Coalition Interrogatory # 34

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3

Interrogatory:

Does Hydro One still have a Customer Advisory Board? If so, please provide notes of all meetings from the past two years and what information from those meetings did Hydro One use in developing this application?

Response:

No, Hydro One no longer has a Customer Advisory Board.

School Energy Coalition Interrogatory # 35

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 1.3-A01

Interrogatory:
With respect to the Ipsos Distribution Customer Engagement Report:

a) Please provide a copy of the retainer and/or contract between Hydro One and Ipsos.

b) Please provide a copy of the terms of reference and work plan.

Response:
The terms of the agreement and work plan are outlined in Exhibit I-23-SEC-035, Attachment 1.

Dx Customer Engagement Plan

May 18, 2016

Two-Phases

Phase 1	To inform Dx plan (Qualitative and Quantitative)	Summer 2016
Phase 2	Validate earlier results and to add any new or additional customer insights	Winter 2016 or Spring 2017

Phase 1 Detailed Approach for Residential & Small Business

	Focus groups	Surveys
Specific format	• Recorded small group discussions led by IPSOS • Audio recording of sessions • Customers recruited by phone by Ipsos and offered compensation for time	• Online panel survey with representative sample of residential customers • Online open-link survey posted for R&SB customers (with in-bound telephone number for telephone interviewing for 6 week period, referral to Hydro One for paper survey requests and/or questions) • Telephone survey with representative sample of residential, small business and First Nations customers
Details	• **8 online groups total, half with Residential (7-9 per Residential group(, half with Small Business (4-6 per small business group)**	• Both online surveys supported by a workbook provide an opportunity to inform customers of context, recent performance and investment options and solicit input on customer expectations and priorities • Online with representative sample of residential customers (n=1500) via panel sample, max 15 minutes, device agnostic, not AODA compliant • Online open-link survey posted for R&SB customers (with in-bound telephone support and live interviewer interviewing over 6 week period) • Representative telephone survey to provide a reflection of the uninformed customer's reaction to trade-offs and bounds of support that is projectable to entire customer base as well as offering greater representation of rural and low income customers. Telephone survey will intentionally offer minimal education to customers. 20 minutes max. n=500 residential / n=-200 small commercial. / n=300 First Nations based on flag in Hydro One database
Screening criteria	• Residential customers: Balance demographics and consumption level • Small business: Balanced industry and consumption representation	• Residential customers: Proportionate sample by region, density, rural/non-rural, household income • Small business: Proportion sample by region / demand vs non demand. • First nations: Proportion sample by region only.
Materials needed	• Recruitment screener • Moderator guide / script	• Ipsos to design surveys
Key dates	• Focus groups to occur post-quantitative launch	• Online and telephone rep surveys: assuming sign-off on questionnaire by May 20: Fieldwork 6/2– 6/30 (online and telephone surveys will field concurrently). • Open link survey: 6/2 – 7/10
Other Considerations	• Ipsos to recruit participants and pay incentives	

Phase 1 Detailed Approach for C&I, LDA & LDC Segments

	Group workshops	Surveys
Specific format	• Presentation by HONI staff • Audio recording of sessions • Plenary + Small-group breakout sessions facilitated by Ipsos	• Online survey link and workbook emailed directly to ALL C&I, LDA and LDC customers by Hydro One

Details	• 10 in person workshops with ~15 customers in each, per the following:
	  • 1 in Essex (Commercial & Industrial only)
	  • 2 in London (Co-locate – separate sessions with C&I and LDA/LDC)
	  • 2 in Hamilton (Co-locate – separate sessions with C&I and LDA/LDC)
	  • 2 in Collingwood (Co-locate – separate sessions with C&I and LDA/LDC)
	  • 1 in Kingston (possibility of C&I, LDA, LDC combined)
	  • 1 in Timmins (possibility of C&I, LDA, LDC combined)
	  • 1 in Thunder Bay (possibility of C&I, LDA, LDC combined)
		• IPSOS to use standard online survey platform (not online consultation tool) and provide link to Hydro One to email out.
		• Costs assume cleaning of verbatim comments and coding of open-ends will be capped at 200. If >200 completes are received a random sampling will be cleaned/coded.

Screening criteria	• C&I: Balance across key sub-segments • LDA: All customers invited to nearest workshop • LDC: All customers invited to nearest workshop	• Assume Hydro One will send out survey to only those organizations that did not attend workshop or one-on-one. One survey per organization.
Materials needed	• Screener/script for recruitment • Master deck for presentations • Customer workbooks and related materials (per segment) • Discussion moderator guide/script	• Ipsos to design surveys
Key dates	• Workshops to be held concurrent with focus groups, post quantitative launch	• TBD
Questions	• Hydro One to recruit participants and provide representative for presentations	

Qualitative Research Summary – Audiences & Proposed Locations

The table below summarizes the audiences, proposed locations and approach per audience/location:

<table>
<tr><th rowspan="2">Market</th><th colspan="4">Audience</th></tr>
<tr><th>Residential & Small Business</th><th>Commercial & Industrial (C&I)</th><th>Large Distribution Accounts (LDA</th><th>Large Distribution Company (LDC1)</th></tr>
<tr><td>GTA/Horseshoe</td><td>Focus Groups</td><td colspan="3"></td></tr>
<tr><td>Southwestern Ontario</td><td>Focus Groups</td><td>Workshop</td><td colspan="2">Workshop</td></tr>
<tr><td>Hamilton</td><td rowspan="6"></td><td>Workshop</td><td colspan="2">Workshop</td></tr>
<tr><td>Collingwood</td><td>Workshop</td><td colspan="2">Workshop</td></tr>
<tr><td>Kingston</td><td colspan="3">Workshop</td></tr>
<tr><td>Timmins</td><td colspan="3">Workshop</td></tr>
<tr><td>Thunder Bay</td><td colspan="3">Workshop</td></tr>
<tr><td>Essex</td><td>Workshop</td><td colspan="2" rowspan="3"></td></tr>
<tr><td>Southeastern Ontario</td><td>Focus Groups</td><td rowspan="2"></td></tr>
<tr><td>Northern Ontario</td><td>Focus Groups</td></tr>
</table>

Responsibilities
- Residential and Small Business

Customer Segment	Channel	Hydro One role	Vendor role
Residential and small business	Online workbook / survey rep sample and open-link Telephone survey of residential customers and small commercial	• Provide workbook in PowerPoint form	• Provide panel sample • Write surveys • Execute surveys • Analyze survey results (separately for representative sample and open survey, with cuts by sub-segment) • Provide preliminary analysis to inform focus group design if possible based on timeline
	Focus groups	• Define target geographies • Hydro One representative to do Q&A with customers following moderated discussion	• Select and recruit participants • Design focus group and create content based on workbook • Write any questionnaire • Online access/ hosting solution • Professional moderator • Produce recording/transcript • Integrate results into final report • Manage customer compensation • Summarize results and synthesize into overall report

Responsibilities - C&I, LDA, LDC

Customer Segment	Channel	Hydro One role	Vendor role
Commercial & Industrial Large Distribution Accounts (LDA) Local Distribution Companies (LDC)	Workshops	• Identify customers to invite and issue invitations • Present context and investment • Participate in breakout discussions • Provide presentation materials	• Secure facilities • Provide draft questionnaire • Provide discussion questions • Distribute and collect customer questionnaires • Professional moderators facilitate breakout discussions (2-3 breakouts per workshop depending on scale) • Write summaries of breakout discussions • Summarize results and synthesize into overall report • Ipsos to provide note takers and provide summaries for one-on-ones
Project management support			• Track scheduling and completion of all engagements • Send weekly update emails to Hydro One team • Escalate risks and issues to Hydro One staff • Troubleshoot issues to ensure quality and engagement level goals are met
Final deliverables			• Produce report for use by Asset Management team to update Investment Plan and inclusion in regulatory filings

Phase 1 – Timeline*

	May				June				July					August		
	2-8	9-15	16-22	23-29	30-6	7-13	14-20	21-27	28-3	4-10	11-17	18-24	25-31	1-7	8-14	15-21
Design questionnaires / sample frame																
Finalize questionnaire and workbook content																
Program, test and launch online/ telephone rep residential / business / First Nations					Aiming for June 2 or 6 launch											
Post online open-link survey					Aiming for June 2 or 6 launch and open for 6 weeks											
Email online C&1. LDC, LDA survey link to Hydro One					Aiming for June 6 launch											
Tabulate and analyze survey results																
Recruit participants																
Design discussion guide																
Conduct focus groups/workshops																
Synthesize/analyze qualitative results																
Prepare Final Report for both qual/quant																

Interim Report July 17

Final Report Aug. 10

Phase 1 – Costs

The costing assumptions have been outlined below. Should the assumptions or parameters (such as survey length, field period, or sample size etc.) change the costs may need to be revised. Analysis and report writing has been included in the costs. These costs exclude HST and exclude travel which will be billed at cost.

Task	Cost Per Unit	TOTAL
15 min. online panel survey (n=1500 rep sample of residential customers) with workbook (device agnostic, French/English with up to 5,000 words translated, Not AODA compliant)	N/A	$
15 min. online open-link with workbook (device agnostic, French/English, Not AODA compliant)with inbound call line for those wishing to complete the survey by phone or mail. Ipsos will host telephone survey and re-direct those with questions or wishing for a mail survey to Hydro One for 6 week period. Costs are based on in-bound survey up to n=100 completes and mail completion up to n=50. Costs for online open-link assume that the coding of open-ends and cleaning of verbatim comments are based on a cap of n=5000 completed surveys. If > 5000 completes are received, a random sample of n=5000 completed surveys will be coded/cleaned.		$
15 min. online large customer survey: LDA, LDC, C&I (sent out by HO) (n= unknown) Costs assume cleaning of verbatim comments and coding of open-ends will be capped at 200. If >200 completes are received a sampling will be cleaned/coded.		$
20 min max. telephone representative sample: residential (n=500), general service (n=200), First Nations (n=300). French/English. MAX DIFF ANALYSIS that will be included in each R&SB survey component is included here.		$
Focus Groups x 8	$	$
Workshops x 10	$	$*
Note taking (per one-on-one, estimate 10 at the moment)	$	$
	TOTAL	$+ HST

OEB Staff Interrogatory # 75

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.1: Distribution System Plan Overview, Section 1.1.1 (5.2.1 A) Key Elements of the DSP, pg 23 of 2930.

> *"A top priority for Large Customers is to improve power quality. To address this, Hydro One has created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue they are experiencing. Furthermore, a capital power quality program has been incorporated into the plan. Hydro One has also increased the funding for reliability enhancement projects to specifically target Large Distribution Account ("LDA") and mid-size industrial customers."*

Interrogatory:

a) What percentage of the incremental costs of these programs are borne by the Large Distribution Account and mid-size industrial customer classes?

b) Has Hydro One considered directly allocating the incremental cost of these programs to these customer classes?

Response:

a) It is not possible to determine the percentage of incremental costs for the referenced programs borne by the Large Distribution Account and mid-size industrial customers. However, these customers typically fall within the Sub-Transmission and Demand-billed General Service rate classes. Based on the USofAs in which these capital and OM&A costs are included, and how the Cost Allocation Model allocates the costs in these USofAs, Hydro One estimates that about 20% of the total incremental costs of the programs referenced in this interrogatory are allocated to the Sub-Transmission and General Service Demand-billed rate classes.

b) The incremental changes to these programs will help the LDA accounts and mid-size industrial customers but will also provide broader benefits to all customers connected to the same distribution circuits impacted by these programs. As such, Hydro One submits it is appropriate that all distribution customers share the cost of these programs. This approach is consistent with the OEB's cost allocation model methodology, which allocates these types of costs to all customer classes based on each rate class' peak demands and number of customers.

OEB Staff Interrogatory # 76

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 1.3 (5.2.2) Page: 1449
Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.3 Summary of Customer Needs and Preferences

The Ipsos Report showed the following:

- *"Customer service improvements above existing levels are not something for which customers are willing to pay higher rates."*

Interrogatory:
Considering the above statement regarding customer preference, please explain why Hydro One is pursuing programs that are intended to improve customer service, but will contribute to higher rates, such as the new complaint system "GP-16 Customer Self-Service Technology" 16 or "GP-33 Customer Service Complaint Management Tool".

Response:
GP-16 Self-Service Technology

This investment is required to upgrade and enhance Hydro One's self-service technology, including the MyAccount self-service website and mobile app. Some of the underlying technology supporting these applications is out of date, no longer supported by the vendor, and needs to be updated to simply maintain the existing level of functionality. In addition, there are some features which customers are requesting, such as the ability to report power outages online or via the mobile app, which will improve customer service and reduce operational cost. Customers are requesting additional capabilities in self-service technology that are conveniently available 24/7. The increased use and adoption of these services clearly demonstrates this trend.

Implementing new self-serve technologies in the Customer Service area will ensure that existing services continue to be maintained and new functionality will be delivered to customers. This investment will provide incremental value to ratepayers in the following ways:

- Improve customer engagement by providing a mechanism for customers to conveniently interact with the company;
- Better educate and inform customers about their electricity usage;
- Increase enrolment in support programs such as Ontario Electricity Support Program and the First Nations Delivery Credit;
- Provide customers a streamlined online and mobile experience; and
- Promote consumers easy access to information and interactive portals.

GP-33 Customer Service Complaint Management Tool

Hydro One does not have an effective way to manage, monitor, and provide visibility to customer complaints. As a result, complete and robust customer information is often not available to assist the employee handling the complaint. As such, an investment is required to develop a complaint management tool. Workflows can help customer service employees by routing the complaint to the appropriate group(s) that is in the best position to address the customer's complaint. Other customer-centric workflows include reminders designed to alert staff if they are lagging on tasks that impact the resolution of a customer's complaint.

The centralization of complaints will also ensure issues are addressed quickly and will provide analytics to conduct trending of the root causes of customer's complaints so that the company can handle these issues pro-actively and in turn, reduce the number of complaints going forward.

OEB Staff Interrogatory # 77

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3 (5.2.2) Page: 1450

Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.3 SUMMARY OF CUSTOMER NEEDS AND PREFERENCES

The Ipsos Report showed the following:

- *"Large Customers want improved outage customer communications with more accurate estimates of power restoration."*

Interrogatory:

a) Please identify if any of the proposed projects or changes in operating practices are intended to address this customer preference.

b) If so, are costs related to those projects or changes assigned to large customer classes or is Hydro One proposing that they be allocated to all customers?

c) If those costs would be allocated to all customers, please explain the rational for that approach.

Response:

a) Customers can receive information on outages through a variety of mechanisms. Hydro One's outage map provides details on any planned and unplanned outages in its service territory. Some large customers also have direct access to Hydro One's Ontario Grid Control Centre should an outage occur.

To improve outage communication, Operating developed an alert system within the Outage Response Management System ("ORMS") that sends a direct notification to the local Customer Operations Manager if a large customer is affected by an outage. This enables the Customer Operations Manager to have direct contact with their large customers.

To improve the accuracy of estimated timing of power restoration ("ETR"), Operating is exploring ORMS enhancements that will enable the field to update outage restoration information in real-time via mobile devices, which will provide customers real-time information that is more reflective of dynamic field conditions.

Furthermore, Operating is exploring enhancements to the customer portal, allowing large customers to directly input their own incidents or directly view restoration information in real-time of outages affecting them. This is included in the upgrade for the Network Outage Management System ("NOMS"); please refer to section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD-GP-20.

b) Hydro One proposes that customers share the associated costs according to the cost allocation method described in Exhibit G.

c) The improvements identified in a) represent only a small incremental cost to the total cost of operating ORMS and NOMS, which provides benefits to all customers. As such, the total costs for these outage management and restorations tools are shared among all customer classes per the OEB's cost allocation principles.

OEB Staff Interrogatory # 78

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3 (5.2.2) Page: 1451
Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.4 (5.4.1 F) How the Plan Reflects Customer Needs and Preferences

The evidence indicates:
"2. Customers asked that Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases.
Response: Hydro One has implemented a number of productivity initiatives to reduce unit and operational costs and the associated rate impacts. These productivity initiatives are detailed in Section 1.5."

Interrogatory:

a) Please describe how Hydro One intends to track the results of these productivity initiatives.

b) Will the proposed tracking method enable Hydro One to quantitatively demonstrate that it has successfully achieved the expected results set out in this filing?

Response:

Please refer to Exhibit I-25-Staff-123, parts b) and c).

CEB Staff Interrogatory # 79

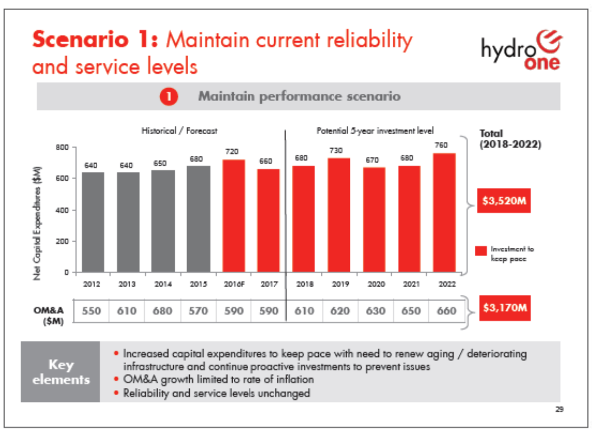
Issue:

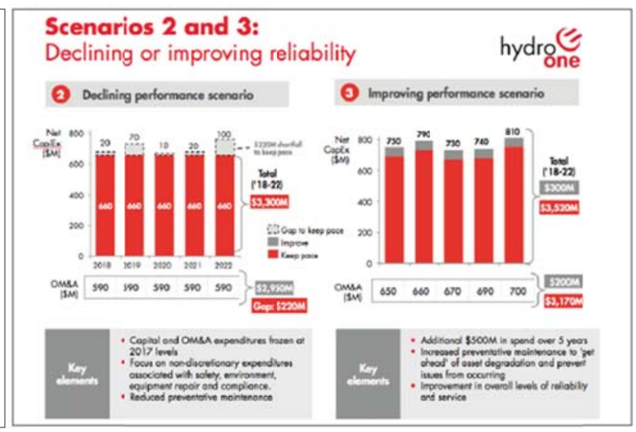
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.3 (5.2.2) Page: 1696-1697

Coordinated Planning with Third Parties - Customer Engagement, Workshop Materials: Customer Reaction to Illustrative Investment Scenarios





Interrogatory:

a) What is the precise definition of "reliability" used as the basis for the illustrative investment scenarios displayed above?

b) Does Hydro One have a quantitative basis for its confidence in declaring the relative reliability performance outcomes associated with each of the different investment scenarios? If yes, please provide details of the associated calculations.

c) When seeking opinions of the general public about matters such as tree cutting program expenditure levels, does the public have understandable information regarding the trade-offs between the various choices?

   i. How has Hydro One explained to the public the trade-offs between the various choices and is it always relative to cost?

ii. In what forum does the public have to challenge the information as provided to them in the public forums? Has there been any challenge in the past? If so, please provide the correspondence.

Response:

a) Reliability in this context is defined by the two following measures found in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.3, Attachment 1, p. 1697:
   - Average number of outages
   - Average duration of each outage

b) Based on a draft 2016 Investment Plan available at the time, Hydro One developed additional scenarios to present a spectrum of investment and associated outcomes for the purpose of facilitating discussion with customers. Those additional scenarios were not developed with specific investments or cuts in mind. Therefore, the associated reliability quantitative outcomes were illustrative only. For clarity, the scenarios were not presented to customers as a menu of investment plan options to choose from, as they did not represent fully developed plans. They were intended only as a discussion tool to determine needs and preferences.

c) Hydro One employs many methods to educate members of the general public about its products and services, including but not limited to publishing information on the Hydro One website, responding to enquiries, and through community engagement events. These educational opportunities provide insight into why Hydro One does what it does, which is helpful in the understanding of the rates that Hydro One charges.

   i. The Hydro One website has a page (link below) dedicated to explaining electricity charges that are on our statements. The link between cost and services is explained in these educational materials. https://www.hydroone.com/rates-and-billing/rates-and-charges/residential

   ii. Members of the public use several communication channels to express concerns related to Hydro One's existing rates, and proposed rate increases. Members of the public can share their opinions by telephone, website and written correspondence. The public also has the ability to attend the rate hearing to challenge Hydro One evidence. They also have the ability to review materials after they are filed on our website. The public can and does ask questions of Hydro One by e-mail, through their key account managers, through the call centre, or through open houses and community events across the province.

OEB Staff Interrogatory # 80

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.4-A01 (5.2.3) Page: 1948
Performance Measurement and Outcome Measures, Section 1.4.3.1 Customer Focused Projects

"Customer Self Service Technology ISD GP 16.
This investment addresses the need to enhance customer experience through additional self-service tools and functionality. This investment is expected to improve customer engagement by providing a convenient mechanism through which customers can interact with Hydro One. This investment also provides customers with a streamlined online experience that allows them to better understand their bills. This investment is expected to improve the My Account Customer Satisfaction and Customer Satisfaction Survey Results measures."

Interrogatory:

a) Have customers requested that Hydro One make additional capital investments to improve their self-service experience and interactions with Hydro One?

b) Please explain why this investment represents value to ratepayers.

Response:

a) Please refer to Exhibit I-23-Staff-76.

b) Please refer to Exhibit I-23-Staff-76.

OEB Staff Interrogatory # 81

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.4-A01 (5.2.3) Page: 1948
Performance Measurement and Outcome Measures, Section 1.4.3.1 Customer Focused Projects

"Call Centre Technology ISD GP 28.
This investment addresses the need to replace a system that has reached end-of-life. The investment also addresses the need to improve customer satisfaction and operational efficiencies at the call center, especially for commercial and Industrial customers. This investment is expected to positively impact the Customer Satisfaction Survey Results, Call Centre Customer Satisfaction, First Contact Resolution and Telephone Call Answered on Time measures."

Interrogatory:

a) Please explain in detail how Hydro One concluded that the call center "system ... has reached end-of-life".

b) How does this proposed investment provide additional value to ratepayers, given that ratepayers have expressed limited interest in enhanced communications, as per the ISPOS survey?

c) Are commercial and industrial customers expected to bear the cost of this project, given its focus on improving satisfaction and operational efficiencies directed at them?

Response:

a) Hydro One's Computer Telephony Integration (CTI) and Interactive Voice Response (IVR) systems were last replaced in 2004. Some of the software components are no longer supported by the vendors, and Hydro One has challenges finding replacement hardware for other components. Thus, Hydro One has concluded that the system has reached end of life. This represents an operational risk should a component fail, as Hydro One's contact centre currently handles 2.4 million calls per year.

b) The majority of the cost associated with this investment is to replace end-of-life technology that is critical to customer operations and enables Hydro One's continued communications with customers. Since 2004, vendor options have improved, and enhanced solutions are available. There are some opportunities for operational efficiencies, which over the long term, will result in cost reductions.

c) As detailed in Section 3.8 of the DSP (ISD GP 28), this investment provides benefits to all customers that use contact centre services, the majority of which are residential customers. As such, Hydro One submits it is appropriate that all customers bear the cost of this project consistent with the OEB's cost allocation model methodology that allocates these costs to all customer classes based on the "NFA-ECC" (net fixed assets excluding capital contribution) allocator appropriate to the General Plant USofA accounts 1920 and 1925 applicable to this investment.

OEB Staff Interrogatory # 82

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 1.4-A01 (5.2.3) Page: 1948
Performance Measurement and Outcome Measures, Section 1.4.3.1 Customer Focused Projects

"Customer Data and Analytics ISD GP 32.
This investment will upgrade several customer analytic tools provided by Hydro One. This investment is required to improve customer satisfaction through implementing alerts and analytics functionality. This investment is expected to improve Customer Satisfaction Survey Results as customers would have access to tools to help them manage energy usage."

Interrogatory:

a) Will improved data analytics save ratepayers money? If yes, please provide examples.

b) What other concrete benefits will this expenditure deliver to ratepayers?

Response:

This investment can save ratepayers money and provide other benefits. In December 2016, Hydro One introduced new tools to help customers manage their electricity usage and cost of their electricity bill. The new tools include: ebilling, e-mail notification if the customer's bill is ready, payment due-date reminders, payment over-due reminders, high usage alerts, and an enhanced web portal to monitor electricity usage. The investment outlined in ISD GP 32 is required to maintain and enhance analytical capabilities and implement the next generation of notifications and high usage alert services in 2020 and 2021.

Hydro One seeks to become a trusted advisor by helping customers understand their energy usage. These investments will provide Hydro One's customer service agents greater insights into customer operations, thus facilitating a more effective response to customer needs. High usage alerts provide customers with greater insight and visibility into their electricity consumption and allow them to better proactively manage their electricity use. These investments also provide customers with specific insights and savings tips that they need to more effectively manage their energy consumption and electricity bill. These customer benefits may also reduce the number of high bill calls into the contact centre since customers will no longer be surprised with their usage.

As of December 31, 2017, the solution has resulted in the following enrolments. Enrolments are expected to increase throughout the 2018-2022 rate term.

- Over 110,000 customers have enrolled in the new eBilling solution.
- 99,000 customers enrolled in “payment due soon” reminders.
- 98,000 customers enrolled in “payment overdue” reminders.
- 30,500 customers enrolled for “high usage alert” notifications.

OEB Staff Interrogatory # 83

Issue:
Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:
B1-01-01 Section 3.8 (5.4.5.2) Page: 2618

Attachments: Material Investments, ISD: SR-07 Distribution Lines Trouble Call and Storm Damage Response Program.

"Investment Need:
Service interruptions associated with distribution lines invariably occur that require immediate response by Hydro One personnel. Extreme weather or asset failures may result in a service interruption that requires restoration of power to customers. Regular patrols and inspections may also identify damaged or failed distribution line assets that pose a safety hazard or customers may report power quality issues. Hydro One personnel must be dispatched to assess and resolve any urgent deficiency in accordance with good utility practice and the requirements of the Distribution System Code."

Interrogatory:
Please provide the historical estimated and actual capital spend for this investment grouped by the following subcategories.

- Emergency pole and line equipment replacements.
- Emergency submarine and underground cable replacements.
- Storm damage response and resolving service interruptions caused by adverse weather conditions.
- Post trouble-call response and providing permanent solutions to any temporary repairs that were required during an emergency or a service interruption.
- Power quality response requiring modifications to the system to resolve unacceptable voltage or frequency levels.
- Damage claims, including payment for third party damage that Hydro One cannot recover.

Response:

Please see table below for the capital spend data grouped by the categories requested.

	2015		2016		2017	
	Board Approved ($M)	**Actual ($M)**	**Board Approved ($M)**	**Actual ($M)**	**Board Approved ($M)**	**Forecast ($M)**
Emergency pole and line equipment replacements.	16.7	21.7	17.4	19.0	17.3	23.5
Emergency submarine and underground cable replacements.	4.0	4.6	4.2	3.7	4.3	4.9
Storm damage response and resolve service interruptions caused by adverse weather conditions.	28.9	39.9	30.3	35.9	30.9	43.1
Post trouble-call response (*including permanent solutions to temporary repairs*) and Power quality response.	6.7	9.2	6.8	15.1	7.0	6.9
Damage claims (*including payment for third party damage that Hydro One cannot recover*).	2.0	2.0	2.1	2.2	2.2	2.6

OEB Staff Interrogatory # 84

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 3.8 (5.4.5.2) Page: 2675

Attachments: Material Investments, ISD: SS-03 Reliability Improvements,

Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-06 Reliability Improvements

"Alternative 2: Targeted Reliability Improvements (Recommended)
Implement targeted projects to improve reliability in areas where customer concerns have been raised and where practical system development opportunities exist to meaningfully improve system capability and performance."

Interrogatory:

a) Please explain for project RI-3 why no capital contribution was provided by customer when the feeder is a dedicated supply to the customer.

b) Is a business case available for each of the projects listed? If no, please provide an explanation to why not. If yes, please provide the business case(s). It is expected the business case(s) will address the following items:
   - List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
   - Reliability metrics for stations and feeders involved in each project and the expected improvement
   - Station and feeder capacity
   - Number of customers affected
   - Proposed options, including scope of work, benefits, costs, and expected efficiency savings.

c) Projects RI-4 and RI-5 in investment SS-03 Reliability Improvements were repeated from D-06. Please explain why these projects were not completed and where the approved capital was redirected.

Response:

a) Investment RI-3 is not a dedicated supply for one customer. The feeder is being built to improve reliability for multiple customers.

b) No. A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. At this point in time, all of the Reliability Improvement projects listed in exhibit ISD SS-03 are planned to be in service at a future date, beyond which necessitates the production of a Business Case for the purpose of authorizing the expenditure of funds for execution.

c) These projects were not completed as capital was redirected to other higher priority capital investments through Hydro One's Investment Planning Process. DSP Section 2.1 explains Hydro One's Investment Planning Process in detail. As described in DSP Section 2.1 this process occurs on an annual basis, "Hydro One's planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board's filing requirement of a consolidated five-year capital plan. All investments follow this same process." The redirected capital for these projects funded part of Hydro One's total 2016 actual and 2017 forecast capital expenditures. DSP Section 3.6 summarizes the result of implementing the cyclical investment planning process. DSP section 3.6.1 summarizes the variances between forecast and historical budgets by OEB Investment Category.

OEB Staff Interrogatory # 85

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 3.8 (5.4.5.2) Page: 2687
Attachments: Material Investments, ISD: SS-06 Worst Performing Feeders

"Alternative 2: Initiate Program to Modernize Worst Performing Feeders (Recommended)
This alternative specifically targets those feeders whose contribution to SAIFI/CAIDI is three times the average feeder's contribution.

The program will invest in communication to open point switches, installed sectionalizers, and feeder breakers. These investments will allow the grid control room to more quickly identify the origin of a fault and perform operational actions in order to improve reliability. Also, this program will address those feeders where an asset-based approach or vegetation management programs cannot eliminate high numbers of momentary outages.
Initial estimates suggest that this program itself could, over time, increase the reliability of the distribution network by approximately one percent."

Interrogatory:

a) Hydro One stated that this program is estimated to increase reliability by approximately one percent. Please provide the study that justifies this statement.

b) Please provide in practical terms what a residential customer on an upgraded feeder is expected to experience. Does this align with residential customer's concern of rising distribution costs?

c) Please provide the list of projects expected to be completed under this investment over the five years.

d) Is a business case available for each project? If no, please provide an explanation as to why not. If yes, please provide the business cases. It is expected the business case will address the following items:

- List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
- Reliability metrics for stations and feeders involved in each project and the expected improvement
- Station and feeder capacity
- Number of customers affected
- Proposed options, including scope of work, benefits, costs, and expected efficiency savings.

e) Please explain the operational philosophy of a "self-healing-grid". Is each of the listed projects capable of self-healing on a standalone basis?

f) This system is expected to be integrated into the Distribution Management System. What is the status of this functionality? What are the capabilities of this system with the self-healing-grid?

Response:

a) The initial estimated improvement is SAIDI was for 1%, however Hydro One has now performed a more detailed analysis of potential improvement on the 43 worst performing feeders. This detailed analysis indicates that with the implementation of the proposed plans, system SAIDI could be reduced by 0.48 hours (please see Table 1 below). As outlined in DSP Section 1.4, Table 10 the 2016 SAIDI excluding LOS but including FM is 12.6 hours, which translates to a system SAIDI improvement of 3.8% (0.48 / 12.6 = 3.8%).

Table 1 – Analyzed Worst Performing feeder list

Project Name	2014-2016 Average SAIDI Contribution	Expected SAIDI Improvement	Expected system SAIDI reduction
HONEY HARBOUR DS F1	0.1372	5%	0.0069
DORSET DS F2	0.1161	7%	0.0081
EMSDALE DS F3	0.0765	12%	0.0092
MUSKOKA TS M1	0.0751	32%	0.0240
PORT ARTHUR TS M6	0.0682	21%	0.0143
SMITHS FALLS TS M26	0.0657	35%	0.0230
TROUT CREEK DS F1	0.0573	16%	0.0092
MANITOULIN TS M25	0.0548	16%	0.0088
COE HILL DS F2	0.0505	14%	0.0071

MINDEN TS M2	0.0492	55%	0.0270
MANITOULIN TS M26	0.0481	2%	0.0010
ORANGEVILLE M45	0.0470	27%	0.0127
ORILLIA M2	0.0467	64%	0.0299
PALMERSTON TS M3	0.0451	61%	0.0275
TROUT LAKE TS M7	0.0441	5%	0.0022
SHINNING TREE DS F3	0.0430	13%	0.0056
MUSKOKA TS M2	0.0424	57%	0.0242
MUSKOKA TS M4	0.0403	44%	0.0178
MURILLO DS F1	0.0403	23%	0.0093
WALLACE TS M6	0.0394	38%	0.0150
WALLACE TS M4	0.0362	47%	0.0170
SMITHS FALLS TS M25	0.0353	53%	0.0187
GRAND BEND EAST DS F2	0.0337	18%	0.0061
OTONABEE TS M27	0.0333	24%	0.0080
WOLVERTON F1	0.0315	42%	0.0132
ARNPRIOR TS M2	0.0290	37%	0.0107
BROCKVILLE M6	0.0288	22%	0.0063
MURILLO DS F3	0.0288	30%	0.0086
COMBERMERE DS F3	0.0285	13%	0.0037
SCHOMBERG DS F3	0.0282	21%	0.0059
TILSONBURG TS M10	0.0265	11%	0.0029
MUSKOKA TS M10	0.0263	61%	0.0161
MARTINDALE TS M5	0.0262	12%	0.0031
PICTON TS M5	0.0250	56%	0.0140
WAUBAUSHENE TS M7	0.0247	51%	0.0126
SNOW ROAD DS F2	0.0241	18%	0.0043
CLARABELLE TS M8	0.0233	35%	0.0081
CHESTERVILLE TS M1	0.0231	27%	0.0062
ALMONTE TS M28	0.0219	7%	0.0015
HAVELOCK TS M1	0.0210	23%	0.0048
COBDEN TS M6	0.0210	42%	0.0088
OWEN SOUND TS M25	0.0206	14%	0.0029
WAUBAUSHENE TS M1	0.0199	64%	0.0127
	Total		0.4792

b) The customers supplied by these feeders currently experience outages that are significantly longer than average compared to the rest of Hydro One's customers, in some cases more than 200 hours a year. A residential customer on an upgraded feeder is expected to experience an average outage reduction of 30%. See Table1 above for the expected SAIDI improvement for each feeder.

c) The types of solutions that could be implemented under the Worst Performing Feeders investment are outlined in DSP ISD SS-06. Presently, 43 feeders have been reviewed for execution in 2018 and 2019. Please refer to Table 1 above for a list of these projects. The list of projects for future years will be produced as reliability data for those years becomes available.

d) A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. Please refer to I-23-Staff-85 Attachment 1 for available business case summaries of projects planned for execution in 2018.

e) Self-healing grid is a "modern grid that will perform continuous self-assessments to detect, analyze and respond to disturbances, and as needed restore grid components or network sections". Projects covered under the Worst Performing feeder program can include self-healing network capabilities that will be under the control of the DMS system.

f) The DMS has self-healing grid functionality as part of its Fault Location, Isolation and Service Restoration (FLISR) power system application. The DMS is able to identify the likely location of the fault based on signals received from deployed devices, create a switching plan that isolates the faulted section, and create an additional switching plan that will restore power to customers in non-faulted sections. This can be provided to the operator to act on or the system can be put in autonomous mode and take actions without manual intervention. This functionality will be implemented and tested as part of the DMS Enhancement project described in DSP ISD SS-07.

Business Case Summaries

Exhibit I Tab 23 Schedule Staff-85

Attachment 1

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

Investment Name: WPF Wallace TS M6 REMOTE OPERABLE SWITCHES		
AIP #: AIP005826	Subject ID: 81733	Claim #: 51003049
AR: 25241	Investment Driver: N.D.C.2.02	In-service Date: Oct 31, 2018
This Approval: $790k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 790

Investment Summary:

Wallace TS M6 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3.3 million. The feeder has 103 km of right of way and supplies 5724 customers.

This investment will install 3 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser. According to defect reports there are roughly 100 cross arms needing replacement in an off road section right outside the station for a 6 km stretch that are scheduled to be replaced also.

The cost for the project is based on a unit cost per switch ($120k), a recloser upgrade ($30k) and cross arm replacement ($4K). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 3 remote operable switches, upgrading the recloser and the cross arm replacement on the Wallace TS M6 is expected to provide a 38% reliability improvement which translates to an estimated average of 1,236k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	790		790
OM&A and removals			
Gross Investment Cost	790		790
Recoverable			
Net Investment Cost			

Note: Not for use for projects $1 Million or greater. Include all previous approvals

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 29 18

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

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

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

Author: Barry Evans
Date: Jan 25, 2018

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

hydro one

Investment Name: WPF Wallace TS M4 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81698	Claim #: 51002952
AR:25235	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $480k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 480

Investment Summary:

Wallace TS M4 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of ~3 million. The feeder has 50.2 km of right of way and supplies 4280 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

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

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches to Wallace TS M4 is expected to provide a 47% reliability improvement which translates to an estimated average of 1,425k of CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	480		480
OM&A and removals			
Gross Investment Cost	480		480
Recoverable			
Net Investment Cost	480		480

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 29 '18

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

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

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

Author: Barry Evans
Date: Jan 24, 2018

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

Investment Name: WPF Trout Creek DS F1 Fault Indicators and OCR Upgrade		
AIP #: AIP005826	Subject ID: 81702	Claim #:51002963
AR: 25220	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $96k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 96

Investment Summary:

Trout Creek DS F1 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 4.5 million. The feeder has 214km of right of way and supplies 1950 customers. The average outage duration was 4.5 hrs and average time from outage notification to arrival at the outage site is 1.6 hrs.

This investment will upgrade an inline switch to an electronic Hubbel Versa-Tech recloser, and install 22 Communicating Fault Current Indicators (CFCI) at 10 strategic locations. The CFCIs will give Operations real time information when the fault occurs. This information will improve reliability by using the information provided by the CFCIs to reduce the area to be searched in order to locate the fault. The upgrade of an existing switch to electronic recloser will improve sectionalizing capability. When a fault occurrs downstream of the existing switch, the electronic recloser will eliminate the outage time for customers that are not in the faulted section, improving the reliability to these customers.

The cost for the project is based on a unit cost per CFCI ($3k), and unit cost for Hubbel Versa Tech recloser ($30k). The unit costs were developed based on historical costs and known material costs and estimated labour costs agreed upon with the service provider.

Other Alternatives Considered

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

Benefits

Adding 22 CFCI devices and upgrade of an existing line switch to a Hubbel Versa Tech recloser on the Trout Creek DS F1 is expected to provide a 16% reliability improvement which translates to 712k CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	96		96
OM&A and removals			
Gross Investment Cost	96		96
Recoverable			
Net Investment Cost	96		96

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: Konrad Witkowski	Date: Jan 29th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature: Peter Faltaous	Date: Jan 29, 2018

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

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

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

Author: Janet Canale
Date: January 25, 2018

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

hydro one

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

Investment Summary:

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

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

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

Other Alternatives Considered

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

Benefits

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

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

Project Risk Assessment

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

Signature Block

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

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

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

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

Author: Nathan Cox
Date: January 5, 2018

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

hydro one

Investment Name: WPF Schomberg DS F3 Communicating Faulted Circuit Indicators		
AIP #: 005826	Subject ID: 81726	Claim #: 51003033
AR:25248	Investment Driver: N.D.C.2.02	In-service Date: October 31,2018
This Approval: $45k	Previous Approval: 0($k)	Total Approval: (Gross Inv. in $K):45

Investment Summary:

Schomberg DS F3 was identified as one of the worst performing feeders between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.16 million. The feeder is 135 km in length and supplies 2090 customers. The average outage duration was calculated at 3 hours per customer.

This investment will install 15 Communicating Fault Current Indicators (CFCI) at 5 strategic locations to give Operations real time information when the fault occurs. This information will improve reliability by using the CFCIs to reduce the area to be searched in order to locate the source of the fault.

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

Other Alternatives Considered

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

Benefits

Adding 15 CFCI devices to Schomberg DS F3 is expected to provide a 21% reliability improvement which translates to 445k CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	45		45
OM&A and removals			
Gross Investment Cost	45		45
Recoverable			
Net Investment Cost	45		45

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: January 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 25, 2018

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

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

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

Author: Murxmur Ola
Date: January623rd, 2018

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

hydro one

Investment Name: WPF – Port Arthur TS M6 Regs, CFCIs and OCR Upgrade		
AIP #: AIP005826	Subject ID: 81715	Claim #:51003013
AR:25221	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $390k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 390

Investment Summary:

Port Arthur TS M6 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 5.4 million. The feeder has 214km of overhead and 26.2km of underground lines and supplies 3,637 customers. The average outage duration was 7.5 hours with almost 2 hours of that time spent searching for the location of the outage.

This investment will install 20 Communicating Fault Current Indicators (CFCI) at 8 strategic locations, upgrade two hydraulic reclosers to G & W Viper reclosers, and install 3 sets of regulators at 3 identified locations. The CFCIs and reclosers will give Operations real time information when the fault occurs. This information will improve reliability by reducing the area to be searched in order to locate the fault. When an outage occurs on the feeder, a portion of the feeder will be transferred to an alternate supply. This will significantly reduce the outage time for customers that are not on the faulted section. The regulators will provide the necessary voltage support to enable the load transfer.

The cost for the project is based on a unit cost per CFCI ($3k), unit cost per G & W Viper ($120K), and unit cost for1 set of regulators ($30K). The unit costs were developed based on historical costs and known material costs and estimated labour costs agreed upon with the service provider.

Other Alternatives Considered

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

Benefits

Adding 20 CFCI devices, three (3) sets of regulators and upgrading of two (2) sets of OCRs to G&W reclosers on Port Arthur M6 is expected to provide a 21% reliability improvement which translates to 1.16M CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	390		390
OM&A and removals			
Gross Investment Cost	390		390
Recoverable			
Net Investment Cost	390		390

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 29, 2018

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

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

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

Author: Janet Canale
Date: January 24, 2018

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

hydro one

Investment Name: WPF Orillia TS M2 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81687	Claim #: 51002920
AR: 25183	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $960k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 960

Investment Summary:

Orillia TS M2 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3.7 million. The feeder has 48 km of right of way and supplies 6908 customers.

This investment will install 8 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

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

Other Alternatives Considered

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

Benefits

Adding 8 remote operable switches to Orillia TS M2 is expected to provide a 64% reliability improvement which translates to an estimated average of 2.5M CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	960		960
OM&A and removals			
Gross Investment Cost	960		960
Recoverable			
Net Investment Cost	960		960

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Jan 22nd/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature: [signature]	Date: Jan 23, 2018

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

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

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

Author: Mark van Tol
Date: January 12, 2018

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

hydro one

Investment Name: WPF Muskoka TS M4 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81710	Claim #: 51003017
AR: 25226	Investment Driver: N.D.C.2.02	In-service Date: November 30, 2018
This Approval: $270k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 270

Investment Summary:

Muskoka TS M4 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3.18 million. The feeder has 43 km of right of way and supplies 4304 customers.

This investment will install 2 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. The switch locations sectionalize the line so Operations can restore power to a section of the feeder from an alternate supply (Minden TS M2). When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will add telemetry and control to the existing in-line recloser M4RCS.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 2 remote operable switches and upgrading the recloser M4RCS on Muskoka TS M4 is expected to provide a 44% reliability improvement which translates to an estimated average of 1.394 million of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	270		270
OM&A and removals			
Gross Investment Cost	270		270
Recoverable			
Net Investment Cost	270		270

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Janu 25/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature: [signature]	Date: Jan 25, 2018

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

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

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

Author: Betty Savoie
Date: January 22, 2018

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

hydro one

Investment Name: WPF Muskoka TS M10 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81713	Claim #: 51003009
AR: 25228	Investment Driver: N.D.C.2.02	In-service Date: November 30, 2018
This Approval: $510k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 510

Investment Summary:

Muskoka TS M10 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.066 million. The feeder has 73.7 km of right of way and supplies 4661 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section of the feeder from an alternate supply. The other two locations provide sectionalizing on the feeder. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will add telemetry and control to the existing in-line recloser CLR.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches, and upgrading CLR on Muskoka TS M10 is expected to provide a 61% reliability improvement which translates to an estimated average of 1.254 million of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	510		510
OM&A and removals			
Gross Investment Cost	510		510
Recoverable			
Net Investment Cost	510		510

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: January 25/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 25, 2018

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

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

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

Author: Betty Savoie
Date: January 22, 2018

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

hydro one

Investment Name: WPF Muskoka TS M1 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81718	Claim #: 51003021
AR:25229	Investment Driver: N.D.C.2.02	In-service Date: November 30, 2018
This Approval: $870k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 870

Investment Summary:

Muskoka TS M1 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 5.9 million. The feeder has 105 km of right of way and supplies 9960 customers.

This investment will install 7 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. Two of the switch locations is a tie point to adjacent feeders (Waubaushene TS M1 & Parry Sound TS M2) and will allow Operations to restore power to different sections near the end of the feeder from an alternate supply. The other locations provide sectionalizing, so when an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser M1RCS.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 7 remote operable switches and upgrading recloser M1RCS on Muskoka TS M1 is expected to provide a 32% reliability improvement which translates to an estimated average of 1.878 million of CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	870		870
OM&A and removals			
Gross Investment Cost	870		870
Recoverable			
Net Investment Cost	870		870

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: January 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature: [signature]	Date: Jan 25, 2018

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

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

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

Author: Betty Savoie
Date: January 22, 2018

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

Investment Name: WPF Murillo DS F3 Remote Operable SW + CFCIs + OCR		
AIP #: AIP005826	Subject ID:81709	Claim #:51002996
AR:25212	Investment Driver:N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $483k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K):483

Investment Summary:

Murillo DS F3 was identified as a worst performing feeder between 2014 and 2016 with average Customer Minutes of Interruption (CMI) of 3.0 million. The feeder has 143.6 km of right of way and supplies 1073 customers. The average outage duration was 5.5 hrs and average time from outage notification to arrival at the outage site is 1.3 hrs.

This investment will upgrade a hydraulic recloser and a fuse to electronic G&W Viper reclosers, upgrade two tie switches to electronic G&W Viper reclosers with six voltage sensors, and install 1 Communicating Fault Current Indicator (CFCI) at a strategic location. All new equipment installed will give Operations real time information when a fault occurs. This information will improve reliability by reducing the area to be searched in order to locate a fault. In addition, the G&W Viper reclosers installed at tie points will allow Operations to restore power to a section of the feeder from an alternate supply. When an outage occurs on the feeder, this will significantly reduce the outage time for customers that are not on the faulted section, improving the reliability of these customers.

The cost for the project is based on a unit cost of $120k per G&W Viper, and a unit cost of $3k per CFCI. The unit costs were developed based on known material costs and estimated labour costs agreed upon with the service provider.

Other Alternatives Considered

Status Quo: The Do Nothing alternative would lead to similar search times and no improvement in operation flexibility, with no expected improvement in reliability on this feeder.

Benefits

Upgrade a hydraulic recloser, a fuse, and two tie switches to electronic G&W Viper reclosers, and adding a CFCI device on Murillo DS F3 is expected to provide a 30% reliability improvement which translates to 906k CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	483		483
OM&A and removals			
Gross Investment Cost	483		483
Recoverable			
Net Investment Cost	483		483

Project Risk Assessment

This project was not specifically included in the approved 2018-2023 business plan however funds will be redirected from the Worst Performing Feeder Program (AR 24301) that has $7M in 2018.

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: January 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 25, 2018

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

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

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

Author: Cecilia Pang
Date: January 25, 2018

hydro one

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

Investment Name: WPF Murillo DS F1 Remote Operable SW + CFCIs + OCR		
AIP #: AIP005826	Subject ID:81708	Claim #:51002994
AR:25211	Investment Driver:N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $285k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K):285

Investment Summary:

Murillo DS F1 was identified as a worst performing feeder between 2014 and 2016 with average Customer Minutes of Interruption (CMI) of 3.9 million. The feeder has 416.4 km of right of way and supplies 1543 customers. The average outage duration was 5.4 hrs and average time from outage notification to arrival at the outage site is 1.5 hrs.

This investment will upgrade a hydraulic recloser to electronic G&W Viper recloser, upgrade a tie switch to electronic G&W Viper recloser with six voltage sensors, and install 15 Communicating Fault Current Indicators (CFCI) at 7 strategic locations. All new equipment installed will give Operations real time information when a fault occurs. This information will improve reliability by reducing the area to be searched in order to locate a fault. In addition, the G&W Viper recloser installed at the tie point will allow Operations to restore power to a section of the feeder from an alternate supply. When an outage occurs on the feeder, this will significantly reduce the outage time for customers that are not on the faulted section, improving the reliability of these customers.

The cost for the project is based on a unit cost of $120k per G&W Viper, and a unit cost of $3k per CFCI. The unit costs were developed based on known material costs and estimated labour costs agreed upon with the service provider.

Other Alternatives Considered

Status Quo: The Do Nothing alternative would lead to similar search times and no improvement in operation flexibility, with no expected improvement in reliability on this feeder.

Benefits

Upgrading a hydraulic recloser and tie switch to electronic G&W Viper reclosers, and adding 15 CFCI devices on Murillo DS F1 is expected to provide a 23% reliability improvement which translates to 871k CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	285		285
OM&A and removals			
Gross Investment Cost	285		285
Recoverable			
Net Investment Cost	285		285

Project Risk Assessment

This project was not specifically included in the approved 2018-2023 business plan however funds will be redirected from the Worst Performing Feeder Program (AR 24301) that has $7M in 2018.

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 25, 2018

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

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

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

Author: Cecilia Pang
Date: January 25, 2018

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

hydro one

Investment Name: WPF Minden TS M2 Remote Operable Switches and Recloser Upgrade		
AIP #:005826	Subject ID: 81711	Claim #: 51003000
AR: 25223	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $510k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 510

Investment Summary:

Minden TS M2 was identified as one of the worst performing feeders between 2014 and 2016; with average annual Customer Minutes of Interruption (CMI) of 2,066k. The feeder length is 51.5 km and it supplies 5635 customers. The feeder is characterized by long sections of line with difficult off road access.

The scope of this investment will be limited to the installation of four (4) remote operable switches and the upgrade of an existing recloser installation to provide telemetry and remote operating capability. Switches are to be installed at strategic locations and recloser functionality will be optimized to give Operations the ability to sectionalize the faulted portion of the feeder and to restore power from the feeder breaker. One of the remote switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding the four (4) remote operable switches and upgrading the recloser on the Minden TS M2 is expected to provide a 55% reliability improvement which translates to an estimated average of 1,136k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	510		510
OM&A and removals			
Gross Investment Cost	510		510
Recoverable			
Net Investment Cost	510		510

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 25, 2018

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

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

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

Author: Murxmur Ola
Date: January 18, 2018

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

hydro one

Investment Name: WPF Havelock TS M1 REMOTE OPERABLE SWITCHES		
AIP #: AIP005826	Subject ID: 81735	Claim #: 51003061
AR: 25238	Investment Driver: N.D.C.2.02	In-service Date: Oct 31 '18
This Approval: $510k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 510

Investment Summary:

Havelock TS M1 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2 million. The feeder has 115 km of right of way and supplies 8050 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches and upgrading the recloser on the Havelock TS M1 is expected to provide a 23% reliability improvement which translates to an estimated average of 460k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	510		510
OM&A and removals			
Gross Investment Cost	510		510
Recoverable			
Net Investment Cost			

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Jan 29th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature: [signature]	Date: Jan 2?/18

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

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

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

Author: Barry Evans
Date: Jan 25, 2018

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

hydro one

Investment Name: WPF Emsdale DS F3 Line Relocates		
AIP #: AIP005826	Subject ID: 81688	Claim #: 51002922
AR: 25206	Investment Driver: N.D.C.2.02	In-service Date: Oct 31, 2018
This Approval: $700k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 700

Investment Summary:

Emsdale DS F3 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 5.9 million. The feeder has 167 km of right of way and supplies 1553 customers.

This investment will relocate two (2) 1-km sections of offroad line, which have been identified as being a major contributor to outages on this feeder. Relocating these offroad sections to road allowance will reduce the impact of forestry-related outages, and will also improve the ability of Lines staff to identify / repair outages.

The cost for the project is based on field input and historical averages.

Other Alternatives Considered

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

Benefits

Relocating two (2) 1-km sections of offroad line is expected to provide a 12% improvement on reliability which translates to an estimated average of 992k CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	700		700
OM&A and removals			
Gross Investment Cost	700		700
Recoverable			
Net Investment Cost	700		700

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: Konrad Witkowski	Date: Jan 22nd 2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature: Peter Faltaous	Date: Jan 23, 2018

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

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

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

Author: Mark van Tol
Date: January 12, 2018

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

hydro one

Investment Name: WPF Combermere DS F3 Communicating FCIs		
AIP #: AIP005826	Subject ID: 81696	Claim #: 51002944
AR: 25230	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $48k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 48

Investment Summary:

Combermere DS F3 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.7 million. The feeder has 119km of right of way and supplies 970 customers. The average outage duration was 3.2 hours with over 1 hour of that time spent searching for the location of the outage.

This investment will install 16 Communicating Fault Current Indicators (CFCI) at 6 strategic locations to give Operations real time information when the fault occurs. This information will improve reliability by using the information provided by the CFCIs to reduce the area to be searched in order to locate the fault.

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

Other Alternatives Considered

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

Benefits

Adding 16 CFCI devices to Combermere DS F3 is expected to provide a 13% reliability improvement which translates to 350k CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	48		48
OM&A and removals			
Gross Investment Cost	48		48
Recoverable			
Net Investment Cost	48		48

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Jan 29th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature: [signature]	Date: Jan 29 '18

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

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

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

Author: Barry Evans
Date: January 16, 2018

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

hydro one

Investment Name: WPF Coe Hill DS F2 Communicating FCIs		
AIP #: AIP005826	Subject ID: 81667	Claim #:51002834
AR: 25159	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $54k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 54

Investment Summary:

Coe Hill DS F2 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 4.2 million. The feeder has 235km of right of way and supplies 1988 customers. The average outage duration was 3.9 hours with about 2 hours of that time spent searching for the location of the outage.

This investment will install 18 Communicating Fault Current Indicators (CFCI) at 6 strategic locations to give Operations real time information when the fault occurs. This information will improve reliability by using the information provided by the CFCIs to reduce the area to be searched in order to locate the fault.

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

Other Alternatives Considered

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

Benefits

Adding 18 CFCI devices to Coe Hill DS F2 is expected to provide a 14% reliability improvement which translates to 583k CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	54		54
OM&A and removals			
Gross Investment Cost	54		54
Recoverable			
Net Investment Cost	54		54

Note: Not for use for projects $1 Million or greater. Include all previous approvals

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 24th 18

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

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

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

Author: Barry Evans
Date: Jan 24, 2018

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

hydro one

Investment Name: WPF Cobden TS M6 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81699	Claim #: 51002954
AR: 25219	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $360k	Previous Approval: ($k)	Total Approval: (Gross Inv. in $K): 360

Investment Summary:

Cobden TS M6 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.0 million. The feeder has 65 km of right of way and supplies 5383 customers.

This investment will install 3 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

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

Other Alternatives Considered

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

Benefits

Adding 3 remote operable switches to Cobden TS M6 is expected to provide a 42% reliability improvement which translates to an estimated average of 831k of CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	360		360
OM&A and removals			
Gross Investment Cost	360		360
Recoverable			
Net Investment Cost	360		360

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: Konrad Witkowski	Date: January 24th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature: TW Lyberogiannis	Date: Jan 24/18

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

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

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

Author: Barry Evans
Date: Jan 23, 2018

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

hydro one

Investment Name: WPF Chesterville TS M1 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81670	Claim #: 51002843
AR: 25188	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $510k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 510

Investment Summary:

Chesterville TS M1 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.4 million. The feeder has 55 km of right of way and supplies 6014 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches to Chesterville TS M1 is expected to provide a 27% reliability improvement which translates to an estimated average of 647k of CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	510		510
OM&A and removals			
Gross Investment Cost	510		510
Recoverable			
Net Investment Cost	510		510

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 11th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 12 '18

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

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

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

Author: Nathan Cox
Date: January 5, 2018

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

Investment Name: WPF Almonte TS M28 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81672	Claim #: 51002853
AR: 25185	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $129k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 129

Investment Summary:

Almonte TS M28 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 1.7 million. The feeder has 27 km of right of way and supplies 6153 customers.

This investment will install 1 remote operable load break switches and 3 Communicating Fault Current Indicators (CFCI) at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

The cost for the project is based on a unit cost per switch ($120k) and a unit cost per CFCI ($3k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 1 remote operable switches to Almonte TS M28 is expected to provide a [illegible]7% reliability improvement which translates to an estimated average of [illegible] of CMI avoided annually.
128K

Cost			
(in $K)	2018	2019	Total
Capital & MFA	129		129
OM&A and removals			
Gross Investment Cost	129		129
Recoverable			
Net Investment Cost	129		129

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Jan 29'18

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

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

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

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

hydro one

Investment Name: 25209 - BCS - WPF - Trout Lake TS M7 - Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81691	Claim #: 51002930
AR:25209	Investment Driver: N.D.C.2.02	In-service Date: December 31, 2018
This Approval: $270k	Previous Approval: 0 ($k)	Total Approval: (Gross Inv. in $K): 270

Investment Summary:

Trout Lake TS M7 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.6 million. The feeder has 118 km of right of way and supplies 6981 customers.

This investment will install 2 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switches will reduce the outage time for customers that are not supplied by the faulted section. The investment will also add telemetry and control to an existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 2 remote operable switches to Trout Creek TS M7 is expected to provide a 5% reliability improvement which translates to an estimated average of 186k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	270		270
OM&A and removals			
Gross Investment Cost	270		270
Recoverable			
Net Investment Cost	270		270

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: Konrad Witkowski	Date: January 25/2018
Approved by: Peter Faltaous	Manager, Distribution Investment Planning	Signature: Peter Faltaous	Date: Jan 29, 2018

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

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

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

Author: Daniel Boutros
Date: January 12, 2018

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

Investment Name: WPF Palmerston TS M3 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81685	Claim #: 51002912
AR: 25189	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $390k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): $390k

Investment Summary:

Palmerston TS M3 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3.62 million. The feeder has 74.9 km of right of way and supplies 3,350 customers.

This investment will install 3 new remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker and up to three feeder tie points. One 44 kV electronic recloser (M3RCS1) will be upgraded for remote operation. When an outage occurs on the feeder, the switches and recloser will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches to Palmerston TS M3 is expected to provide a 61% reliability improvement which translates to an estimated average of 2,207k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	390		390
OM&A and Removals			
Gross Investment Cost	390		390
Recoverable			
Net Investment Cost	390		390

Project Risk Assessment

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

Signature Block

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

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

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

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

Author: Jerry Vo
Date: January 29, 2018

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

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

Investment Summary:

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

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

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

Other Alternatives Considered

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

Benefits

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

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

Project Risk Assessment

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

Signature Block

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

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

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

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

Author: Jerry Vo
Date: January 29, 2018

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

hydro one

Investment Name: WPF - Martindale TS M5 - Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81740	Claim #: 51003083
AR: 25239	Investment Driver: N.D.C.2.02	In-service Date: Oct 31, 2018
This Approval: $270k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 270

Investment Summary:

Martindale TS M5 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.06 million. The feeder has 92 km of right of way and supplies 4537 customers.

This investment will install 2 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 2 remote operable switches to Martindale TS M5 is expected to provide a 12% reliability improvement which translates to an estimated average of 250k of CMI avoided annually.

Cost

(in $K)	2017	2018	Total
Capital & MFA		270	270
OM&A and removals			
Gross Investment Cost		270	270
Recoverable			
Net Investment Cost		270	270

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Ja 29/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 29, 2018

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

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

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

Author: Soheil Babaei
Date: January 29, 2018

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

Investment Name: WPF – Manitoulin TS M26 – Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81690	Claim #: 51002928
AR: 25208	Investment Driver: N.D.C.2.02	In-service Date: November 30, 2018
This Approval: $150k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K):150

Investment Summary:

Manitoulin TS M26 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3 million. The feeder has 53 km of right of way and supplies 5773 customers.

This investment will install 1 remote operable load break switch at a strategic location to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switch will reduce the outage time for customers that are not supplied by the faulted section. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 1 remote operable switch to Manitoulin TS M26 is expected to provide a 2% reliability improvement which translates to an estimated average of 58k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	150		150
OM&A and removals			
Gross Investment Cost	150		150
Recoverable			
Net Investment Cost	150		150

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Jan 29th/2018
Approved by: Peter Faltaous	Manager, Distribution Investment Planning	Signature: [signature]	Date: Jan 29, 2018

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

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

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

Author: Daniel Boutros
Date: January 12, 2018

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

hydro one

Investment Name: WPF – Manitoulin TS M25 – Remote Operable Switches		
AIP #: AIP005826	Subject ID:81689	Claim #:51002926
AR:25207	Investment Driver:N.D.C.2.02	In-service Date: November 30, 2018
This Approval: $630k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K):630

Investment Summary:

Manitoulin TS M25 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 4.3 million. The feeder has 90 km of right of way and supplies 4770 customers.

This investment will install 5 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 5 remote operable switches to Manitoulin TS M25 is expected to provide a 16% reliability improvement which translates to an estimated average of 700k of CMI avoided annually.

Cost (in $K)	2018	2019	Total
Capital & MFA	630		630
OM&A and removals			
Gross Investment Cost	630		630
Recoverable			
Net Investment Cost	630		630

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: January 25th/2018
Approved by: Peter Faltaous	Manager, Distribution Investment Planning	Signature: [signature]	Date: Jan 29, 2018

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

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

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

Author: Daniel Boutros
Date: January 12, 2018

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

Investment Name: WPF - Clarabelle TS M8 - Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81704	Claim #: 51002978
AR: 25233	Investment Driver: N.D.C.2.02	In-service Date: Oct 31, 2018
This Approval: $360k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 360

Investment Summary:

Clarabelle TS M8 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 1.8 million. The feeder has 32 km of right of way and supplies 5526 customers.

This investment will install 3 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

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

Other Alternatives Considered

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

Benefits

Adding 3 remote operable switches to Clarabelle TS M8 is expected to provide a 35% reliability improvement which translates to an estimated average of 1.187 million of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	360		360
OM&A and removals			
Gross Investment Cost	360		360
Recoverable			
Net Investment Cost	360		360

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Jan 29/2018
Approved by: Peter Faltaous	Manager, Distribution Asset Management	Signature:	Date: Jan 29, 2018

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

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

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

Author: Soheil Babaei
Date: January 29, 2018

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

hydro one

Investment Name: WPF Arnprior TS M2 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81727	Claim #: 51003035
AR: 25186	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $750k	Previous Approval: 0($k)	Total Approval: (Gross Inv. in $K): 750

Investment Summary:

Arnprior TS M2 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.3 million. The feeder has 44 km of right of way and supplies 5120 customers.

This investment will install 6 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 6 remote operable switches and upgrade existing recloser on Arnprior TS M2 is expected to provide a 37% reliability improvement which translates to an estimated average of 843k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	750		750
OM&A and removals			
Gross Investment Cost	750		750
Recoverable			
Net Investment Cost	750		750

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Feb 6th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Feb 1 '18

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

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

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

Author: Charles Wong
Date: Jan 23, 2018

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

hydro one

Investment Name: WPF Smiths Falls TS M26 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81730	Claim #: 51003040
AR: 25178	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $750k	Previous Approval: 0($k)	Total Approval: (Gross Inv. in $K): 750

Investment Summary:

Smiths Falls TS M26 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 5.1 million. The feeder has 86 km of right of way and supplies 8991 customers.

This investment will install 6 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 6 remote operable switches and upgrade existing recloser on Smiths Falls TS M26 is expected to provide a 35% reliability improvement which translates to an estimated average of 1,826k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	750		750
OM&A and removals			
Gross Investment Cost	750		750
Recoverable			
Net Investment Cost	750		750

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Feb 6th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Feb 6 '18

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

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

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

Author: Charles Wong
Date: Jan, 23, 2018

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

Investment Name: WPF Brockville TS M6 Remote Operable Switches and Recloser Upgrade		
AIP #: AIP005826	Subject ID: 81731	Claim #: 51003042
AR: 25187	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $510k	Previous Approval: 0($k)	Total Approval: (Gross Inv. in $K): 510

Investment Summary:

Brockville TS M6 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.3 million. The feeder has 58 km of right of way and supplies 5608 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply. The investment will also add telemetry and control to the existing in-line recloser.

The cost for the project is based on a unit cost per switch ($120k) and recloser upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches and upgrade existing recloser on Brockville TS M6 is expected to provide a 22% reliability improvement which translates to an estimated average of 509k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	510		510
OM&A and removals			
Gross Investment Cost	510		510
Recoverable			
Net Investment Cost	510		510

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature: [signature]	Date: Feb 6th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature: [signature]	Date: Feb 6 '18

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

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

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

Author: Charles Wong
Date: Jan 30, 2018

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

hydro one

Investment Name: WPF Smiths Falls TS M25 Remote Operable Switches		
AIP #: AIP005826	Subject ID: 81669	Claim #: 51002836
AR: 25177	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $480k	Previous Approval: 0($k)	Total Approval: (Gross Inv. in $K):480

Investment Summary:

Smiths Falls TS M25 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 2.8 million. The feeder has 41 km of right of way and supplies 6926 customers.

This investment will install 4 remote operable load break switches at strategic locations to give Operations the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. One of the switch locations is a tie point to an adjacent feeder and will allow Operations to restore power to a section near the end of the feeder from an alternate supply. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section and customers that have an alternate supply.

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

Other Alternatives Considered

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

Benefits

Adding 4 remote operable switches on Smiths Falls TS M25 is expected to provide a 53% reliability improvement which translates to an estimated average of 1,476k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	480		480
OM&A and removals			
Gross Investment Cost	480		480
Recoverable			
Net Investment Cost	480		480

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Feb 6th/2018
Approved by: Ted Lyberogiannis	Manager, Distribution Asset Management	Signature:	Date: Feb 6 18

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

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

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

Author: Charles Wong
Date: Jan 23, 2018

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

Investment Name: WPF – Shiningtree DS F1 – Remote Operable G&W Vipers and Fault Indicators		
AIP #: AIP005826	Subject ID: 81744	Claim #: 51003102
AR: 25243	Investment Driver: N.D.C.2.02	In-service Date: October 31, 2018
This Approval: $288k	Previous Approval: $0k	Total Approval: (Gross Inv. in $K): 288

Investment Summary:

Shiningtree DS F1 was identified as a worst performing feeder between 2014 and 2016 with average annual Customer Minutes of Interruption (CMI) of 3.9 million. The feeder has 179 km of right of way and supplies 700 customers.

This investment will install 2 sets of remotely operable G&W Viper reclosers and 6 Communicating Fault Current Indicators (CFCIs) at strategic locations. The CFCIs will give Operations real time information when the fault occurs. This information will improve reliability by using the information provided by the CFCIs to reduce the area to be searched in order to locate the fault. The G&W reclosers will provide the ability to sectionalize the faulted portion of the feeder and restore power from the feeder breaker. When an outage occurs on the feeder, the switches will significantly reduce the outage time for customers that are not supplied by the faulted section. The investment will also add telemetry and control to the existing station recloser.

The cost for the project is based on a unit cost per CFCI ($3k), a unit cost per G&W Viper recloser ($120k), and the recloser telemetry upgrade ($30k). The unit costs were developed based on historical costs and were agreed to with the service provider.

Other Alternatives Considered

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

Benefits

Adding 6 CFCIs, 2 remote operable G&W viper reclosers and telemetry to the station recloser at Shiningtree DS F1 is expected to provide a 13% reliability improvement which translates to an estimated average of 510k of CMI avoided annually.

Cost

(in $K)	2018	2019	Total
Capital & MFA	288		288
OM&A and removals			
Gross Investment Cost	288		288
Recoverable			
Net Investment Cost	288		288

Project Risk Assessment

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

Signature Block

Approved by: Konrad Witkowski	Senior Financial Advisor, Decision Support	Signature:	Date: Feb 6th/2018
Approved by: Peter Faltaous	Manager, Distribution Investment Planning	Signature:	Date: February 6, 2018

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

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

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

Author: Soheil Babaei
Date: February 6, 2018

OEB Staff Interrogatory # 86

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 3.8 (5.4.5.2) Page: 2691

Attachments: Material Investments, ISD: SS-06 Worst Performing Feeders

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	7.1	10.1	10.5	10.9	11.3	49.9
Operations, Maintenance & Administration and Removals	-	-	-	-	-	-
Gross Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**

**Includes Overhead at current rates.*

Interrogatory:

a) Please explain the reason for the jump in 2019 followed by an annual increase at a rate that is higher than CPI?

b) Please provide Hydro One's historic plan and actual spend on this program.

Response:

a) This program is a new initiative to improve the reliability of the worst performing feeders in the province with a plan to ramp up the investments in 2019, followed by an annual increase of 2% per year. The reflected increase from 2019 to 2022 at a rate higher than CPI is an input error.

b) As this is a new program, no historical spend is available.

OEB Staff Interrogatory # 87

Issue:

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

B1-01-01 Section 3.8 (5.4.5.2) Page: 2692
Attachments: Material Investments, ISD: SS-07 Advance Distribution System, Page 2692 of 2930.
Ref: EB-2013-0416 Exhibit D2/Tab3/Schedule5 2.0 Smart Grid Pilot Project Table 2

"Investment Need:
The ADS investments were part of the smart grid investments outlined in Exhibit D1, Tab 3, Schedule 5 (Customer Services Capital) of EB-2013-0416. They were originally planned for completion within the last approved rate period. Investments were delayed due to a later than anticipated release of a version of software that incorporated more functions into one platform.

The current Distribution Management System ("DMS") went in service in 2012. A lifecycle system refresh is planned to replace hardware and software system components. Specifically, two key sub-projects were delayed: (1) the "DMS Upgrade" project; and (2) the Demand Response for Operations project. The DMS Upgrade project will provide the functionality of the following projects identified on pages 5 to 7 of Exhibit D1, Tab 3, Schedule 5 in Hydro One's last distribution application (EB-2013-0416): DMS Enhancements, Selective Load Shedding, Infrastructure Support, Mobility Solutions and Online Operating Diagrams projects."

Interrogatory:

a) Please provide the pilot project results for each Smart Grid Pilot Project in Table 2.

b) Please provide Hydro One's overall strategy on Smart Grid including all capital investments expected in the short-term and long-term, operational philosophy, scope of work, and cost-to-benefit analysis for the total expected investment.

Response:

a)

Project	Scope of Work	Pilot Results / Expected Benefits
Consumer Research	Perform customer research to understand customer preferences and determine which smart grid technologies would be most beneficial for customers.	Hydro One has participated in an annual consumer research initiative with SmartGrid Canada since 2013. The objective of the research is to understand customer perceptions of smart grid and how utilities can engage customers to participate. Some key findings and trends found are: • Customers do understand time of use rates and say they change their behaviour to accommodate the new rates. • Customers are looking for alerts from the utility when they are trending above normal usage. • About 20% of customers are very likely, with a further 30% being somewhat likely, to participate in demand response programs. • Residential demand response programs do not need to be limited to summer air conditioning programs but could be used in winter demand response schemes on both space heating and water heating. • Customer interest in solar has grown significantly over the last few years, with ~15% very likely to invest even when told the cost.
Demand Response	Enable home energy management systems for Hydro One customers and make customer data securely available to third party applications (i.e. smart phone apps)	• Hydro One conducted a Smart Thermostat pilot program that let customers “bring their own thermostat” into a Hydro One demand response (DR) program. By leveraging the customer’s existing connected smart thermostat, we were able to substantially reduce the cost of load reduction, offering a $100 enrolment incentive compared to the costs of a comparable direct-install DR program such as *peaksaver* PLUS. • From load reduction perspective, smart thermostats offered a viable alternative to *peaksaver* PLUS. Over the 2015 summer period, the pilot achieved average ex ante demand reductions of 0.72kW compared with *peaskaver* PLUS’ maximum of 0.57kW (evaluated according to IESO’s Demand Response Load Impact Protocols). • Customer satisfaction and engagement with the smart thermostats was very high. 96% of participants reported satisfaction with their thermostat and 72% tended to feel more comfortable in their homes after installing the device. • Hydro One also conducted an AutoSave Electric Water Heater pilot program that leveraged existing *peaksaver* PLUS water heater switches to help customers achieve bill savings. The pilot enabled participants to choose a savings schedule to reduce their electric water heating load during peak and mid-peak time-of-use hours. • Based on an internal evaluation conforming with the IESO’s Evaluation Protocols and Requirements, the AutoSave pilot helped customers save $66 (4.5%) off their annual electricity costs. • Hydro One is currently investigating use of intelligent/communicating electric hot water heaters to lower customer bills as well as provide grid-side benefits (i.e. frequency response, soak up surplus base load generation, etc.)
Distribution Management Systems Enhancements	Enable new functionality of the DMS system by upgrading the system to version 3.5. This includes functionality for the power line maintainers (mobile DMS functionality), network operators and management of complex distribution network changes.	• Hydro One is upgrading its Distribution Management System to including the ability to integrate with a Distributed Energy Resource Management System – please see Investment Summary Document SS-07 for details.

Energy Storage Integration	Pilot both battery and flywheel energy storage technologies and integrate into DMS.	• The cost of fully installed energy storage is beginning to approach the cost-effective range for grid investments. • Hydro One is investigating the use of energy storage as a way to defer asset expansions to supply customers with new load that exceeds current asset capacity. • Energy storage is being utilized in the Demand Response for Operations project – please see Investment Summary Document SS-07 for details.

Network Model Build	Accurately model the distribution system in the Geographic Information System and other source systems to support smart grid applications.	• The project successfully delivered a network model for use in the Distribution Management System.
		• There were ancillary benefits from the build of the Network Model for other systems:
		  o Increased accuracy of Geographic Information System data by performing electrical tracing of all network elements and identifying any breaks/inaccuracies in the model.
		  o Established the substation internals for Distribution Substations in the Geographic Information System for use by other systems in the future.
		  o Digitized data and stored them in the source systems.

Distributed Generation Dispatch	Pilot dispatch (on/off/up/down) of both small and large distributed generators (“DGs”).	• Utilizing Distribution Generation Dispatch during planned outages will avoid the use of field crews in executing outages that involve distributed generators. • Hydro One is investigating the use of Distributed Generation Dispatch to increase the hosting capacity of distribution assets.
Selective Load Shedding	Upgrade the Distribution Management Software to enable load shedding at the Distribution Station and feeder section level.	• This project has been incorporated into the upgrade of the Distribution Management System – please see Investment Summary Document SS-07 for details.
Validation of Smart Grid Technologies and Processes	Conduct technical, operational and economic validation of all of the Phase 1 delivered technologies.	The results of the Distribution Management System validation showed that: • Use of the Distribution Management System along with fault location and remote sectionalization can significantly improve reliability. • Case studies from the Owen Sound pilot area showed reliability improvements of 50% on outages that occurred on the feeder trunks through remote sectionalization. • Fault location technology was found to be of significant benefit in getting crews onsite to faulted sections, with case studies showing a 30 minute improvement.
Advanced Metering Infrastructure for Operations	Enhance outage management system to utilize the real time power outage notifications from customer smart meters and provide the ability to confirm outages to the control centre.	• The project delivered the ability to use meters to verify the scope of outages. This has resulted in the Distribution Operations Management Centre being able to increase the number of calls that Hydro One has been able to avoid sending unnecessary crew dispatches from 14% to 23%. • The Advanced Metering Infrastructure is able to return more than 50% of the Real Time Power Outage notifications (i.e. “last gasps”) to enable the Distribution Operations Management Centre to better verify the scope of outages.
Conservation Voltage Reduction	Pilot flattening and lowering voltage profiles on feeders to reduce losses on lines and energy use by consumers.	• Studies on the target feeders for the pilot have found approximately 3% headroom of voltage that could be reduced during Conservation Voltage Reduction to yield about 1.5% energy savings. • Only feeders with high customer counts will be cost effective when applying a Total Resource Cost approach.

Energy Theft & Analytics	Build an analytical system that examines meter and operational data to identify energy theft.	Hydro One implemented a prototype to evaluate the business case before making significant investments. The key findings were: 1. Models were developed to identify data anomalies. While effective in finding anomalies, they were not conclusive for identifying theft of power. 2. Energy balancing, while desirable, is not possible at this time due to the accuracy of aggregating meters, connectivity issues, sentinel lighting accuracy and other factors. 3. Preliminary analysis of the network in the pilot area did not indicate systemic energy theft. 4. A combination of variables is required to predict theft with a high level of accuracy: usage, voltage and meter events. 5. Limited success was found during the prototype with one theft being successfully confirmed. 6. Due to the lack of quantifiable benefits, the broad application of the solution was not supported
Operational Data Store & Analytics	Build a system that relates operational data with other data (meter, asset, customer, etc.) and provides an ability to perform analytics against the integrated "big data" set.	Hydro One implemented an operational data store that relates meter, asset, network and customer data into a single big data store. The use cases this enabled are: • Home Energy Dashboards – providing customers insights into their electricity usage • High Bill Alerts – alerting customers when they are consuming above normal electricity • Customer Load Profile – creating accurate load profiles for customers as inputs to the Distribution Management System and other analytic system.
Online Operating Diagrams	Upgrade the Distribution Management System with the application to produce operating maps and diagrams.	• Hydro One has transitioned its Distribution Operating Maps from being drafted in a Computer Aided Design & Drafting (CADD) to utilizing the Geographic Information System. • The Network Model in the Distribution Management System is based on the Geographic Information System and will be available to users from both the control room as well as in the field through mobile computers.
Mobile Systems	Upgrade the Distribution Management System with new functionalities to enable mobile work forces.	• Hydro One is establishing the Distribution Management System Mobile Field Client that field crews will be able to access from the computers in their trucks – please see Investment Summary Document SS-07 for details. • Hydro One expects that the real-time situational awareness for field crews will aid in storm restorations by reducing the need for pinning paper operating maps.
Demand Response for Operations	Pilot a system that optimizes electricity load and supply on a local basis leveraging all of the variable load (electric vehicle, energy storage, residential/commercial demand response) and generation (dispatchable renewable, energy storage) available.	• Hydro One has selected and is building a Distributed Energy Resource Management System that it will manage the various resources on the grid (e.g. demand response, electric vehicle, energy storage, distributed generation, etc.) – please see Investment Summary Document SS-07. • The most promising use case for the project is the use of demand response to defer asset investments while accommodating growing load requests from large customers.

b) The infrastructure put in place and findings from these Smart Grid pilots will be applied to the overall 10-year Distribution strategy that is currently in development. This strategy will drive specific investment decisions and operational philosophy to optimize and innovate our core over the next 10 years, to meet our customers' needs for reliability, cost effectiveness and customer choice. The Distribution strategy includes advancing our distribution grid capabilities through Distribution Management System (DMS) enablement, advanced metering analytics, and communications infrastructure. With these investments in place, we will continue to modernize our grid through our system renewal programs and through our Worst Performing Feeder program by replacing end of life equipment with smart equipment capable of automation.

Association of Major Power Consumers in Ontario Interrogatory # 1

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:

A-03-01-01
Hydro One Distribution Business Plan 2017-2022

Interrogatory:

a) Page 13: please provide the start and end date for each of the seven planning process stages.

b) Page 12: Please provide the level of investment and number of projects at each of the following stages:

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

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

d) Please provide the % of plans that were optimizable in this business cycle compared to the previous two business cycles.

Response:

a) Please refer to Exhibit I-24-SEC-36.

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.

Association of Major Power Consumers in Ontario Interrogatory # 5

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: 15

Interrogatory:

a) For how long will the Acquired Utilities be kept separate from Hydro One for rate making purposes?

b) When will the DSP for the Acquired Utilities be combined with the DSP for Hydro One?

Response:

a) As was written in the above reference the three Acquired Utilities are now fully integrated into Hydro One's operations. As part of the MAAD approval, each was approved a 5-year deferred rebasing period. Effective January 1, 2021 the Acquired Utilities will also be integrated into Hydro One for rate making purposes. Hydro One has proposed new permanent "Acquired" rate classes to serve these customers.

b) The DSP filed in the application applies to both Hydro One and the Acquired Utilities. As the acquired utilities have been operationally integrated with Hydro One, the planning process described in Section 2.1 of the DSP for Hydro One also applies to them. This is also true for the Asset registry information and the Asset Strategies employed to monitor and maintain the Acquired Utilities' assets (provided in Sections 2.2 and 2.3 of the DSP).

   However, as the acquired utilities will not be integrated for rate making purposes until 2021, Hydro One has provided Appendix A of the DSP, which contains historical information on each of the utilities as well as proposed spending for years 2018 - 2020. For years 2021 and 2022, the acquired utilities have been integrated with Hydro One's proposed plan, and the capital (and OM&A) forecasts provided in the DSP combine the Acquired Utilities with Hydro One's for these two years. Appendix A will no longer be necessary after 2021 when the utilities are integrated for rate making purposes.

Association of Major Power Consumers in Ontario Interrogatory # 6

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 1.1 Page: 1

Interrogatory:

a) Page 2: Please provide a citation for the Study that draws the affordability line at 4-6% of household net income.
b) Is Hydro One aware of any studies that responds to the affordability line for commercial and industrial customers? If yes, please provide.
c) Page 3: Please provide the documented feedback from executive management that resulted in the production of alternative investment Plan B.
d) Page 3: Please provide the documented feedback from the Executive Leadership Team and Board of Directors in its review of the investment plan.
e) Page 3: Where in the investment planning process was it decided the Plan C scenario was not viable? Please provide the investment level of Plan C.
f) Page 3: Please provide the analysis that reflects an estimated degradation of approximately 2% in both SAIDI and SAIFI for Plan C.
g) Page 8: Please provide a listing of the capital investment projects and amounts deliberately deferred.
h) Page 8: Please confirm the total number of distribution stations to be refurbished over the test period.
i) Page 11: Please discuss Hydro One's view of the optimal time to extend the life of an asset through maintenance compared to replacing the asset.
j) Page 12: Please complete the following table:

Investments	2012 $	2013 $	2014 $	2015 $	2016 $	2017 $	2018 $	2019 $	2020 $	2021 $	2022 $
Proactive Programs											
Maintenance Programs											
Demand-Driven Programs											

k) Page 23: Please provide a list of the General Plant investments in this application that are common to both Hydro One's transmission and distribution businesses that were not approved in Hydro One's transmission application EB-2016-0160.

Response:

a) The study was published in November 2008. See the OEB Consultation on Energy Issues Relating to Low-Income Consumers (EB-2008-0150), *Comments of the Low-Income Energy Network (LIEN), Canadian Environmental Law Association (CELA), Advocacy Centre for Tenants Ontario (ACTO), Income Security Advocacy Centre (ISAC) and Toronto Environmental Alliance (TEA).*

b) No, Hydro One is not aware of any studies that address the affordability line for commercial and industrial customers.

c) Hydro One assumes that "alternative investment Plan B" refers to Plan B-modified. Please refer to Exhibit I-3-SEC-4 for the Board of Director materials prepared by executive management. These materials incorporate feedback from the executive management team and the Board of Directors.

d) Please see part c) above.

e) Please see the November 2016 Board of Directors materials provided in Exhibit I-3-SEC-4.

f) The 2% degradation is calculated based on the Plan C forecasted impact on SAIDI for each of the line items in the table multiplied by the contribution to SAIDI of that line item as follows;

Poles: (-18% * 3%) = -0.54% degradation
Stations: (-4% * 4%) = -0.16% degradation
Other Line Components: (-10% * 23%) = -2.3% degradation
Vegetation: (4% * 27%) = +1.08% improvement
Net Impact = -0.54-0.16-2.3+1.08 = -1.92% = 2% degradation

g) Please see Exhibit I-7-CCC-11.

h) From 2018 to 2022, 73 total stations are planned for refurbishment. See section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD SR-06 (Distribution Station Refurbishments) for further details.

i) By definition, maintenance activities are not performed to extend the life of an asset but rather to allow an asset to reach its expected service life. Investments made to extend the life of an asset are capital investments. The optimal time to make a capital investment to extend the life of an asset (for example, by replacement) is when the risk of failure and the consequence of that failure indicate the need.

j) Hydro One does not characterize investments as "proactive" so it is not possible to provide actual or planned funding levels for proactive investments.

For "Maintenance Programs" it is assumed that the funds spent on maintaining existing components of the distribution system is requested. Please see Exhibit C1, Tab 1, Schedule 2 (Sustaining OM&A) for this funding.

For "Demand-Driven Programs", Hydro One assumed this refers to capital funding that is prioritized as demand. Please see Exhibit I-24-AMPCO-34 for a listing of all material capital investments provided in a MS Excel file. See section 3.7 of the DSP (Exhibit B1, Tab 1, Schedule 1) for the requested funding levels for all material capital investments.

k) The table below displays ISDs containing common capital investments in this Application that were not approved within Hydro One's 2017-2018 transmission application (EB-2016-0160). Note: EB-2016-0160 approval was for two years, 2017 and 2018 only, which is not reflective of the scope of investments contained within this Application.

ISD	**Name**
GP03	MFA Servers and Storage
GP05	Hardware/Software Refresh and Maintenance
GP08	PCMIS Modernization and Optimization
GP09	ECM Phase C
GP10	Work Management & Mobility
GP12	Business Process Consolidation
GP13	HR & Pay Related Technology Investments
GP14	Warehouse Scanning Device Replacement
GP15	SAP Treasury Implementation
GP21	Data Centre Remediation
GP22	OGCC Office Remediation
GP23	Integrated Voice Communications and Telephony Refresh
GP	*Investments below the $1M threshold*

Association of Major Power Consumers in Ontario Interrogatory # 8

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 1.1 Page: 21

Interrogatory:

a) Please explain Hydro One's past investment data quality issues.

b) Please provide any internal audits in the last 5 years of HONI's Asset Management Process.

c) Please provide any internal audits in the last 5 years of HONI's Investment Planning process.

d) Please provide any internal audits in the last 5 years of HONI's Asset Data Quality.

Response:

a) Distribution GIS and SAP linkage had some inconsistent data between the two systems. In the past, greater focus was on addressing the data quality issues within transmission data. Now there are plans to update the distribution GIS model, to make the linkage between GIS and SAP-ECC more accurate.

SAP data had completeness issues which stemmed from outdated data needs, unclear accountability of data, and unmonitored data issues and changes. The transmission stations team has fully reviewed the data needs, accountability and has an ongoing process of reviewing data completeness with monitoring and remediation of data issues.

The transmission lines and distribution stations teams have fully reviewed the data needs and accountabilities and plan to complete the activities to address ongoing monitoring and processes in 2018.

The distribution lines team is in the preliminary review phase in 2018.

Please refer to Section 3.7 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD GP-35 on the Asset Analytics Risk Factor project which will improve the quality of the asset risk model.

b) – d) Please refer to Exhibit I-3-SEC-6.

Association of Major Power Consumers in Ontario Interrogatory # 13

Issue:

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

Reference:

B1-01-01 Section 1.4

Interrogatory:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Response:

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

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

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

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

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

e) Hydro One does not track MAIFI and MAIDI.

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

Table 10 - Historical SAIDI Summary

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

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

Table 11 - Historical SAIFI Summary

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

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

Table 12 - Historical CAIDI Summary

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

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

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

Table 13 - SAIDI by Outage Cause, Excluding FM

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

Table 14 - SAIFI by Outage Cause, Excluding FM

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

Table 15 - CAIDI by Outage Cause, Excluding FM

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

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

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

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

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

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

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

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

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

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

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

Customer Interruption Hours

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

Customer Interruption

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

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

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

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

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

Witness: JESUS Bruno

s) The following are classifications of outages/interruptions:

a. Adverse Environment: Customer outages/interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

b. Defective Equipment: Customer outages/interruptions resulting from equipment failures.

c. Tree Contacts: Customer outages/interruptions caused by faults due to trees or tree limbs contacting energized circuits.

Association of Major Power Consumers in Ontario Interrogatory # 16

Issue:

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

Reference:

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

Interrogatory:

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

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

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

Response:

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

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

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

Association of Major Power Consumers in Ontario Interrogatory # 20

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: 12 and 28

Interrogatory:

a) Page 12: Does Hydro One track the age an asset fails for every asset failure?

b) Page 28: Please provide the dates of the Operational Stakeholder Engagement.

c) Page 28: Please provide the dates of the Executive Leadership Team review and Board of Directors review and approval of the draft investment plan.

Response:

a) No. Hydro One does not track the age an asset fails for every asset failure.

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

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

Association of Major Power Consumers in Ontario Interrogatory # 21

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: 30

Preamble: Hydro One indicates if an investment has a material change to scope, schedule or cost from the approved plan, a variance proposal is prepared.

Interrogatory:

a) Please provide the threshold of change in scope, schedule and cost that triggers the need for a variance proposal.

b) Please provide the number of variance proposals prepared in each of the years 2012 to 2017 and the total cost and schedule impact for each year due to variance approvals.

Response:

a) The variance policy thresholds are described below:

Cost Variance Threshold:

- >10% of currently approved expenditures and >$500,000

OR

- >$5 million (2018), previously $4 million (2016-2017), and $2 million (2012 to 2015).

Schedule Variance Threshold:

- Business impactive
  - Materially impacts value (>$10 million (2018)) or benefit of the scope of work; previously: "Materially impacts value or benefit of the scope of work" (up to 2018)

Scope Variance Threshold:

- Project deliverables are modified

OR

- Planning specifications at the functional or performance levels are modified

b) Please refer to Exhibit I-25-EnergyProbe-38 in addition to the below variance proposals.

Year	Number of Variance Proposals (excluding EnergyProbe-038)	Cost Impact at EOY (Excluding EnergyProbe-038)
2012	0	N/A
2013	0	N/A
2014	1	$725,000
2015	3	$85,000
2016	0	$0
2017	1	$710,000

Hydro One cannot provide the total “schedule impact” on a per year basis, as each investment has a different timeline and the sum of the total schedule change is not indicative of the impact of the variance.

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.)

Table 1

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

b) For the 2013-2017 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. Note that 2012 was an IRM year, so no proposed figure is available.

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		NA	NA	NA		NA	NA	NA		NA	NA	NA
	Submersible transformers	NA	NA	NA	NA	54,193	NA	NA	NA	57,066	NA	NA	NA	59,089	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

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

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

Association of Major Power Consumers in Ontario Interrogatory # 25

Issue:

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

Reference:

B1-01-01 Section 2.3 Planned Replacements

Interrogatory:

a) Please complete the attached excel spreadsheet.

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

Response:

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

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

Asset Replacment - Planned

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

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

Association of Major Power Consumers in Ontario Interrogatory # 26

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: - Unplanned Replacements

Interrogatory:

a) Please complete the attached excel spreadsheet.

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

Response:

a, b) Please refer to Attachment 1 to this response for details on unplanned replacements. Hydro One replaces failed components through unplanned replacements.

D24-AMPCO-26
Ref: B1-1-1 Section 2.3

Asset Replacment - On an unplanned basis

Asset Category		Population	# Asset Units											
			# Replaced 2011	# Replaced 2012	# Replaced 2013	# Replaced 2014	# Replaced 2015	# Replaced 2016	# Replaced 2017	# Forecast to be Replaced 2018*	# Forecast to be Replaced 2019*	# Forecast to be Replaced 2020*	# Forecast to be Replaced 2021*	# Forecast to be Replaced 2022*
Station Transformers **(Note 4)**	All		8	5	11	12	5	7	13	9	9	9	9	9
	In Service		8	5	11	12	5	7	13	9	9	9	9	9
	Spares		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mobile Unit Substations			0	0	0	0	0	0	0	2	0	0	0	0
MUS Structures			1	2	1	1	0	1	2	1	1	1	1	1
Reclosers	All		**Note 2**							**Note 3**				
	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														
Poles	All													
	Wood	**Note 1**												
	Steel													
	Concrete													
	Composite													
	Red Pine Wood													
Rights of Way														
Line Transformers	All													
	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													
	Retails Meters													
	Collectors													
	Repeaters													

** The forecast for 2018 to 2022 represents the quantity of unplanned replacements forecast in budget*

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 undertakes unplanned repairs/replacement for these assets categories in order to address the equipment failures as noted in Exhibit I-24-AMPCO-24.
Note 3	A forecast of future unplanned replacements is not available.
Note 4	Station transformer unplanned replacements lag failures as the station load is temporarily supplied by an MUS or transferred to an alternate source until a transformer replacement can occur.

Association of Major Power Consumers in Ontario Interrogatory # 33

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 3.6 Page: 1-3

Interrogatory:

a) Page 1 Table 63: Please update the table to reflect 2017 actuals and evidence updates and provide an excel version of the table.

b) Page 2: Please provide Hydro One's definition of end-of-life compared to expected service life.

c) Page 2: Please provide the annual amount ($) of System Access work: (1) deferred; (2) cancelled; and (3) advanced for each of the years 2012 to 2017.

d) Page 3: Please provide the annual amount ($) of System Service work: (1) deferred; (2) cancelled; and (3) advanced for each of the years 2012 to 2017.

Response:

a) Audited 2017 actuals are unavailable at this time. An update will be filed once they become available. An excel version of Table 63 can be found in Exhibit I-24-AMPCO-33 Attachment 1.

b) Broadly speaking, end-of-life means that the asset's condition has deteriorated to the point that there is a significant probability of failure in the near term. Expected service life is how long an asset would be reasonably expected to remain in service from the time it is placed in service.

c) The majority of System Access investments are non-discretionary and Hydro One completes this work at a time specified by a third party (new customer, road authority, private land owner, etc.). Hydro One does not have discretion to advance, defer or cancel System Access spending.

d) OEB approved figures are not available for 2012-2014 as these were IRM years.

System Service work ($M)

	2015	2016	2017
Deferred	48.5	25.9	*
Cancelled	0	0	0
Advanced	0	0	0

*2017 Audited Actuals are not available and will be provided once they are available.

Category	Historical and Bridge (previous plan and actual)											Forecast (planned)				
	2013	2014	2015			2016			2017 Bridge			2018 Test	2019 Test	2020 Test	2021 Test	2022 Test
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var					
	$M	$M	$M	$M	%	$M	$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	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3	143.1	166.7	116.2	103.7	105.9
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)	628.1	736.4	699.3	711.0	796.5
System OM&A	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)	579.6	584.0	588.3	603.5	608.0

Association of Major Power Consumers in Ontario Interrogatory # 34

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 3.7 Page: 1-3 List of Material Capital Investments Proposed

Interrogatory:

a) Please provide an excel version of the project listing.
b) Please provide the priority ranking for each project and include in part (a).
c) Please provide a schedule that sets out the key asset units to be replaced under each material capital investment project based on Reference # and provide the proposed quantities for each asset group.
d) Please identify the new capital investment project names in EB-2017-0049 that were not included in EB-2013-0416.

Response:

a) Please see the enclosed MS Excel file.

b) Please see the enclosed MS Excel file.

c) Please see Exhibit I-29-SEC-52. For units not provided in Exhibit I-29-SEC-52, please refer to Section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1).

d) Please see the enclosed MS Excel file.

Association of Major Power Consumers in Ontario Interrogatory # 35

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:

B1-02-01 Page: - Executing Strategy

Interrogatory:

a) Please provide any internal audit documents undertaken in the past five years related to Hydro One's Work Execution Strategies.

b) Please provide the key internal performance metrics Hydro One relies on to measure and manage its work execution for (1) capital and (2) OM&A work programs.

c) Page 6: Does Hydro One track standby hours/down time due to circumstances that cause work to be halted or cancelled.

d) Page 7: For the years 2012 to 2017 please provide the number and duration of planned outages compared to actuals.

e) Please provide Hydro One's key performance metrics related to material and equipment availability, strategic sourcing and logistics.

f) Page 12: Please provide the % of work outsourced for Hydro One's (1) Capital Programs and (2) OM&A Programs for the years 2012 to 2017 and forecast for 2018 to 2022.

g) Page 13: Does Hydro One have an internal document that governs its Staffing Strategy. If yes, please provide.

h) Please provide Hydro One's job estimate to actual cost data for the material capital projects in EB-2013-0416.

i) Please provide Hydro One's schedule estimate to actual schedule for the material capital projects in EB-2013-0416.

Response:

a) Please refer to Exhibit I-3-SEC-006.

b) For all of our ongoing program type investments we track unit rates in terms of labour hours and costs. For our larger project type investments we track major milestones such as design completion, work activities, planned outages, and energization dates.

c) Yes, Hydro One tracks down time hours through various admin down time categories. Examples include, training, special projects, contractual time away, adverse weather and union business.

d) We monitor and determine the performance of our execution based on cost and system impact. Planned outages are tracked through their impact to reliability statistics for which we have performance targets and monthly tracking. The number and duration of planned outages vs. actual is not something that is currently being utilized as a performance metric.

e) Planning Index
Measures how well LOBs are planning for any material needs. This index compares the time between purchase requisition approval and requested delivery date against the contractual lead time. If the adequate lead time is not provided the planning index will fail.

Order Fill
Measures how often internal and external deliveries are made on time. If the requested delivery date is greater than the contractual lead time, deliveries are measured against the requested delivery date otherwise deliveries are held to the contractual lead time. Materials are considered delivered on the earlier of the invoice date or GR Document date for external deliveries and the goods issue date for internal deliveries. A three day leeway is given.

Receipting Index
Measures whether LOBs are receipting materials in a timely fashion. This index compares GR Document date to Goods Receipt Date for external deliveries and Goods Issue date to Goods Receipt Date for internal deliveries. Receipting index is marked pass if there is seven or less days between delivery and receipt.

f) We currently only outsource the Cable Locates as a dedicated externally delivered OM&A activity.

- 2014 = 0%
- 2015 = 0%
- 2016 = 1%
- 2017 = 1.2%

Forecast 2018– 2022

- 2018 = 1.4%
- 2019 = 1.3%
- 2020 = 1.3%
- 2021 = 1.3%
- 2022 = 1.2%

g) Please refer to Exhibit I-40-SEC-075.

h) Please refer to the following:

- Exhibit I-23-Staff-084
- Exhibit I-24-Staff-115
- Exhibit I-24-Staff-116
- Exhibit I-26-Staff-159
- Exhibit I-30-Staff-175

i) Please see response to part h) above.

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

Anwaatin Inc. Interrogatory # 8

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?

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

Reference:

A-04-02 Page: 7

> "*In the past year, Hydro One has mapped out all transmission lines and distribution stations and feeders serving First Nations communities and collected relevant system reliability data in order to make sound and targeted investments to improve system reliability for First Nations communities. First Nation communities served by Hydro One are supplied from 55 transmission lines and 89 distribution lines. Historically, approximately 77% of power failures on these transmission lines were caused by deteriorated equipment (e.g., insulators, wood poles, conductor, etc.) or caused by adverse weather (freezing rain, ice, lightning, etc.) Approximately 50% of power failures on distribution lines occur from tree contacts which lead to equipment failures (e.g., poles, transformers, lines failures, etc.).*

> "*Hydro One will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities. The strategy consists of: increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work.*"

Interrogatory:

a) Please provide maps of all the transmission lines, distribution stations and feeders serving First Nations communities referenced above and a description of each such asset, its age, useful life, and planned replacement date.

b) Please provide all system reliability data collected identifying what applies to distribution lines and highlight the relevant data, stations and feeders serving First Nations communities referenced above and the Anwaatin communities.

c) Please provide a chart comparing the reliability data in referred to in (b) with the data for Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

d) Please provide a chart delineating which power failures were on transmission lines, distribution lines/assets and the cause of the failure for each distribution asset or mixed distribution/transmission asset serving
(i) First Nations communities; and
(ii) the Anwaatin communities.

e) Please provide the same chart for Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

f) Please also provide system reliability averages and trends over the 2007-2017 and 2006-2016 10-year periods for each of the following: First Nations communities, the Anwaatin communities, Hydro One's R1 customers, Hydro One's R2 customers, and Hydro One's UR customers.

g) Please provide a chart comparing the percentage of power failures on distribution lines serving: (i) First Nations communities and (ii) the Anwaatin communities that were caused by or related to trees with the percentage of failures caused by or related to trees on distribution lines serving Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

Please also provide averages of these percentages over the 10-year period for each of the following: First Nations communities, Hydro One's R1 customers, Hydro One's R2 customers, and Hydro One's UR customers.

h) Please provide a detailed list of the causes of the power failures on distribution lines and assets serving: (i) First Nations communities and (ii) the Anwaatin communities that were not related to trees.

i) Please provide the percentage of the total power failures on distribution lines and assets serving: (i) First Nations communities, (ii) the Anwaatin communities, and (iii) the rest of Ontario that were attributable to the causes outlined in (h) above.

Response:

a) The maps that have been developed by Hydro One to show the supply to all First Nations reserve lands are shown in Attachments 1 and 2. Attachment 3 also provides a list of First Nations communities' assets, age, condition, and in-service dates (where available).

   The process Hydro Ones uses to identify assets in need of replacement is explained in section Exhibit B1-1-1, DSP Section 2.1 (5.3.1 B) Needs Assessment.

Note: For the analysis from 8b-8i, only 5-year data from 2012-2016 is available. Data prior to 2012 is not available because the data has not been extracted or validated at this time, and it is a timely process to do so. Given the strict timelines, we have reported with readily available 5-year data.

---

b) Figure B.1 illustrates the 5 year average SAIDI values for feeders serving First Nations communities. Anwaatin feeders are highlighted in yellow.

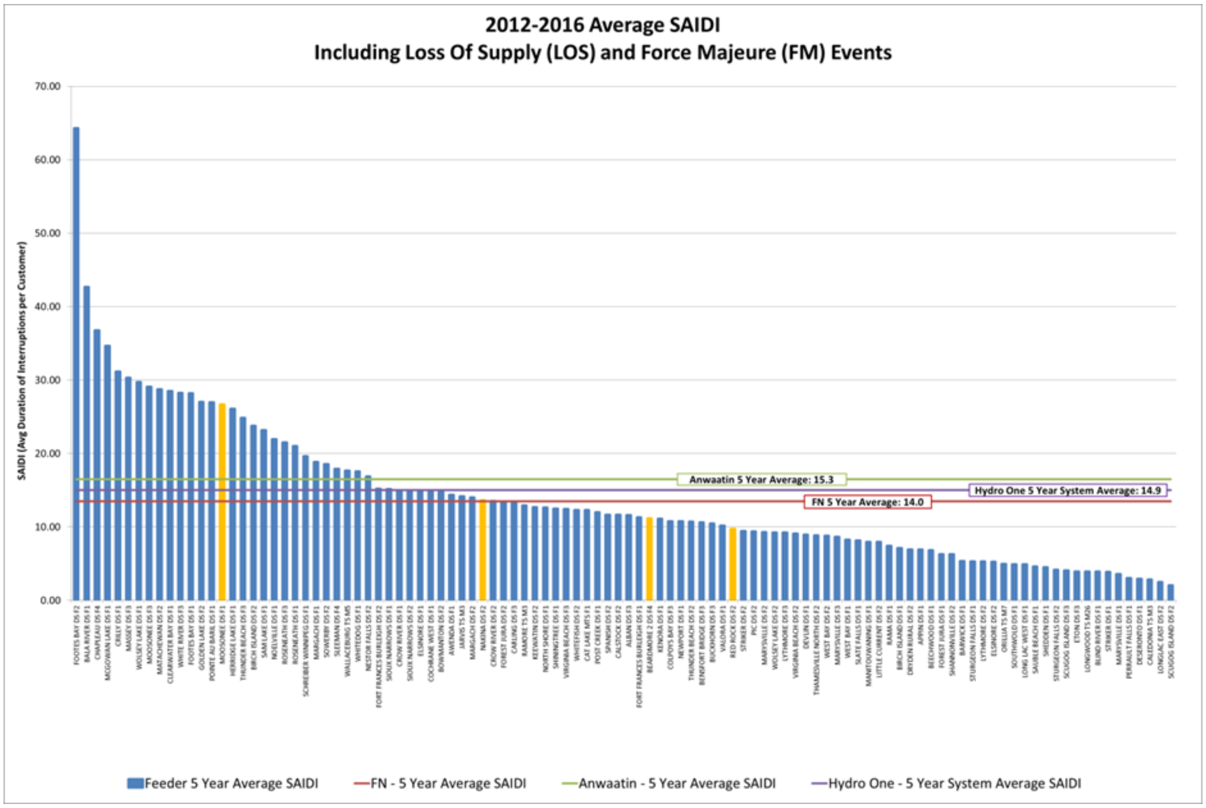


Figure B.1: 5 year average SAIDI for feeders supplying First Nations communities

Figure B.2 below, illustrates the 5 year average SAIFI values for feeders serving First Nations communities. Anwaatin feeders are highlighted in yellow.

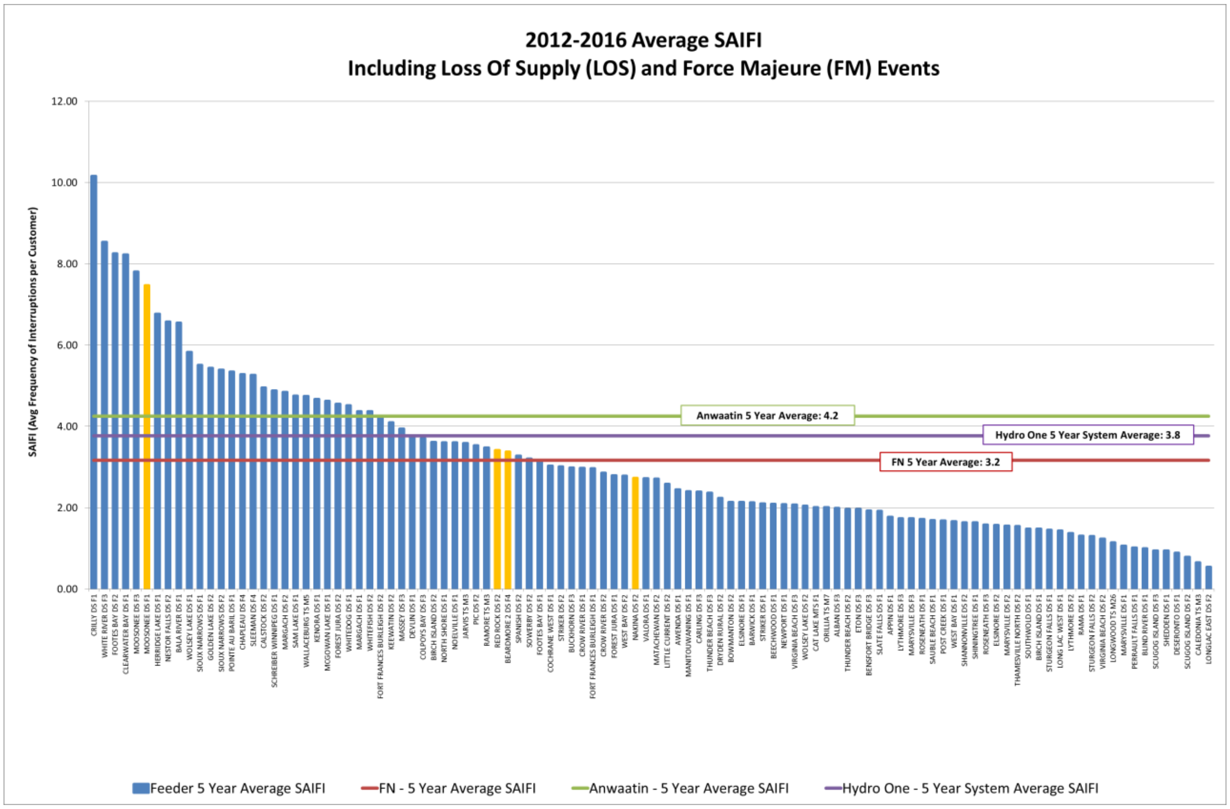


Figure B.2: 5 year average SAIFI for feeders supplying First Nations communities

c) Figures C.1 and C.2 compare the SAIDI and SAIFI values for feeders serving Anwaatin communities with Hydro One's Urban and Rural SAIDI and SAIFI on a year-by-year basis for the past five years.

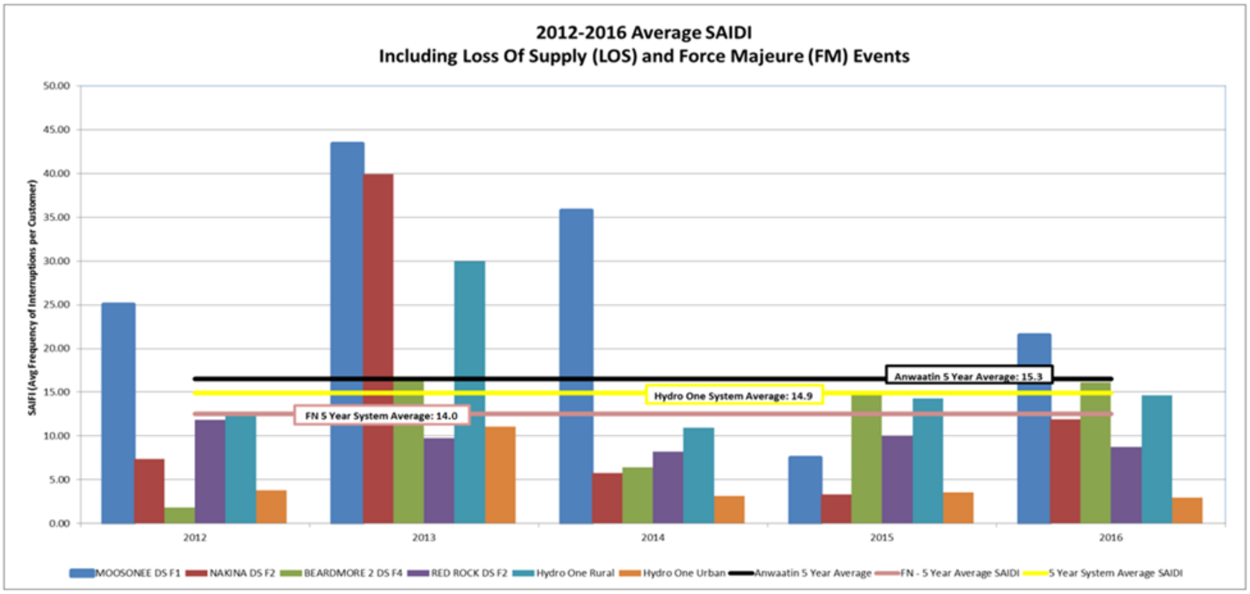


Figure C.1: Comparison of SAIDI from 2012-2016

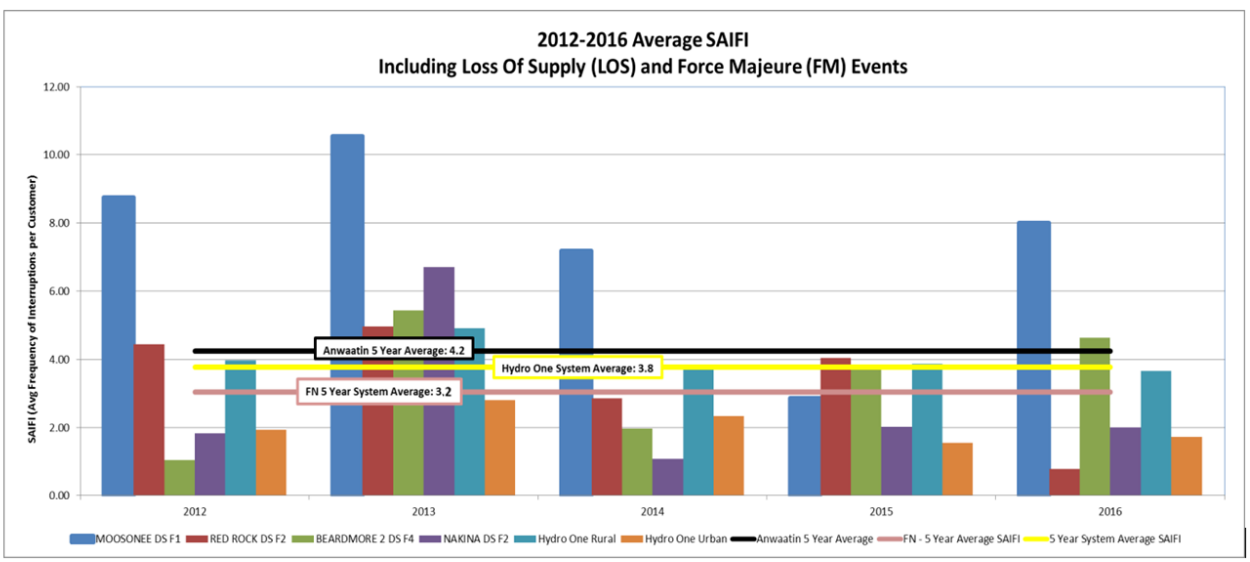


Figure C.2: Comparison of SAIFI from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

d) When customers connected to Hydro One's distribution line experience an interruption, it is due to one of these 8 causes: Adverse Environment, Defective Equipment, Foreign Interference, Human Element, Loss of Supply, Scheduled, Tree Contacts, and Unknown/Other. Loss of Supply refers to customers being interrupted due to a loss of supply on the distribution side as a result of the transmission side.

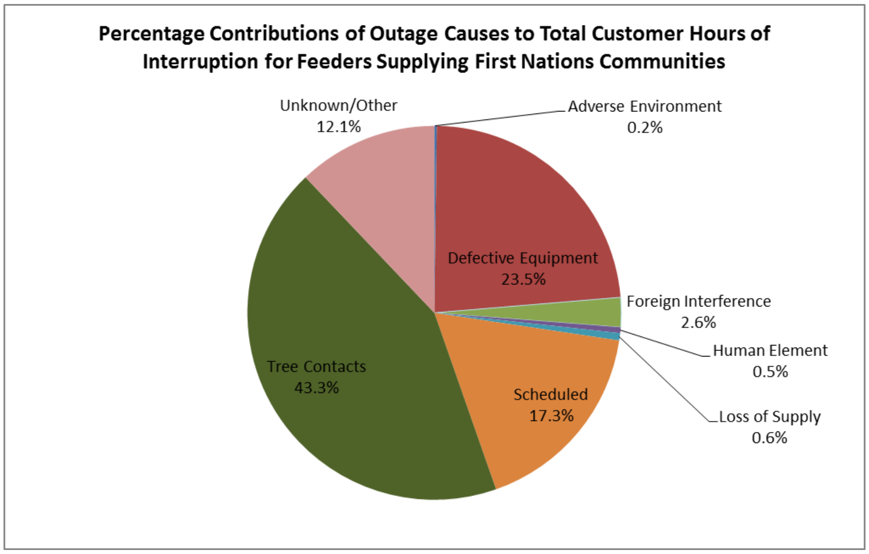


Figure D.1: Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

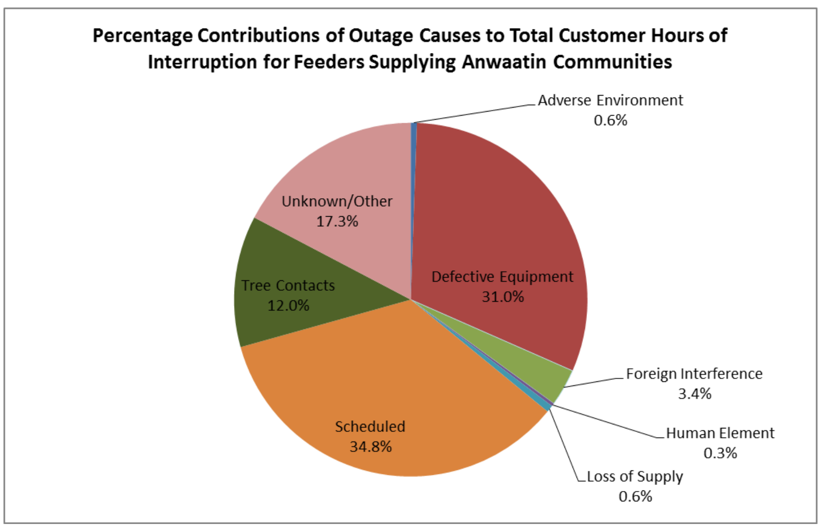


Figure D.2: Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Feeders Supplying Anwaatin Communities – based on data from 2012-2016 e)

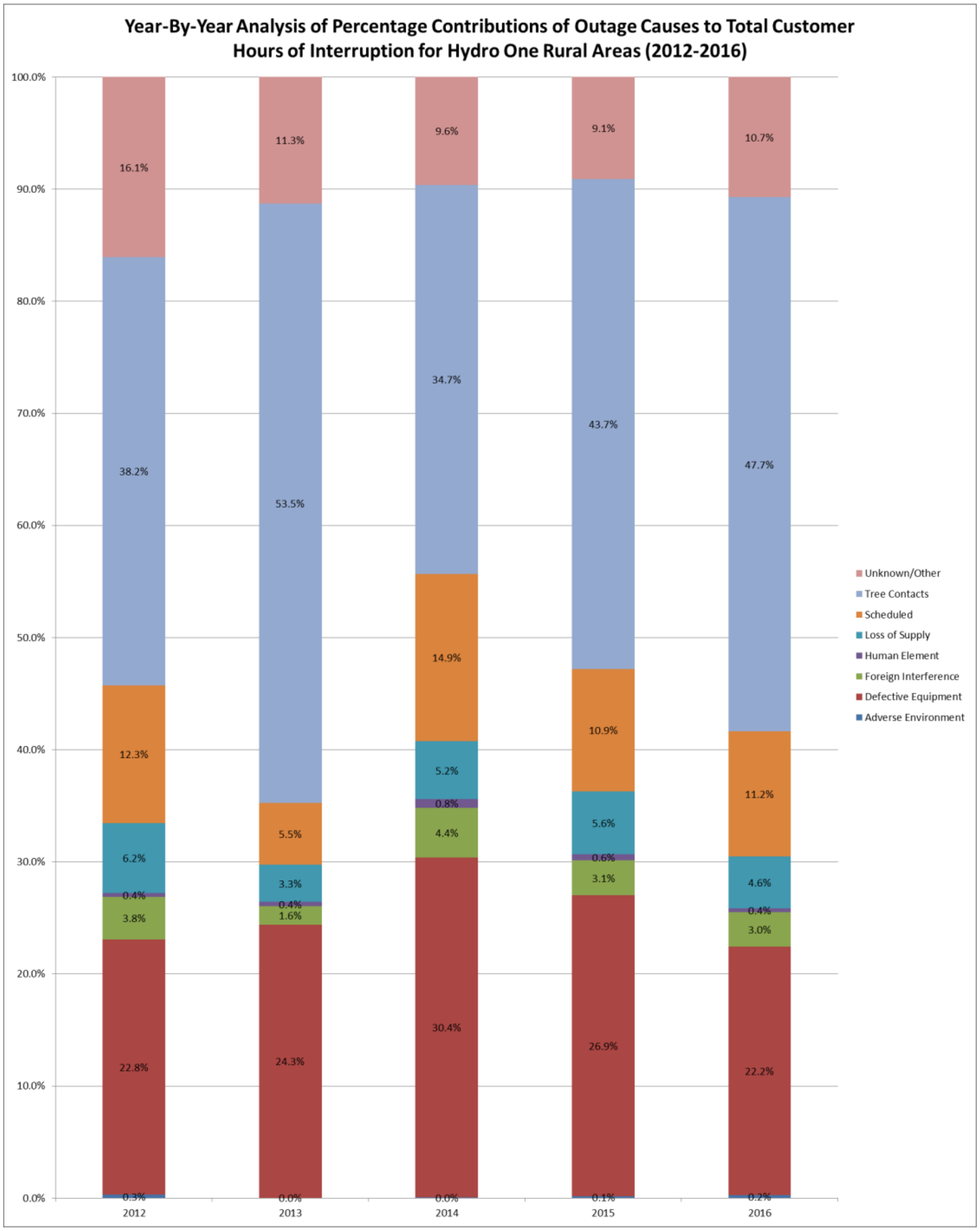


Figure E.1: Year-By-Year Analysis of Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Hydro One Rural Areas (R1 and R2 customers) – based on data from 2012-2016

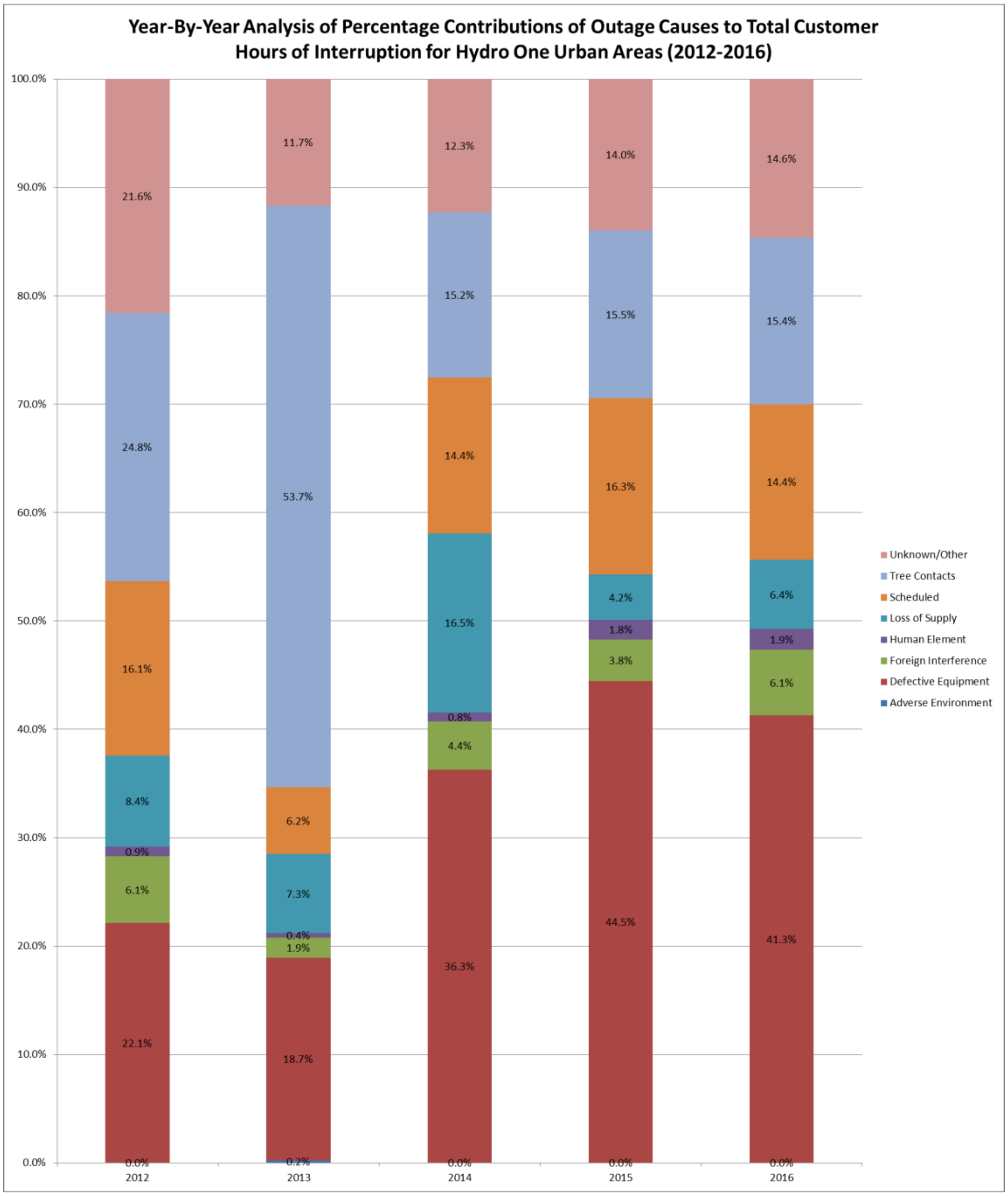


Figure E.2: Year-By-Year Analysis of Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Hydro One Urban Areas (UR Customers) – based on data from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

f) For system reliability averages and trends for feeders supplying First Nations communities and Anwaatin communities, please refer to part b) of this question.

For system reliability averages and trends for Hydro One's Urban and Rural areas, as well as averages and trends for the performance of First Nations communities and Anwaatin communities, please refer to part c of this question.

g)

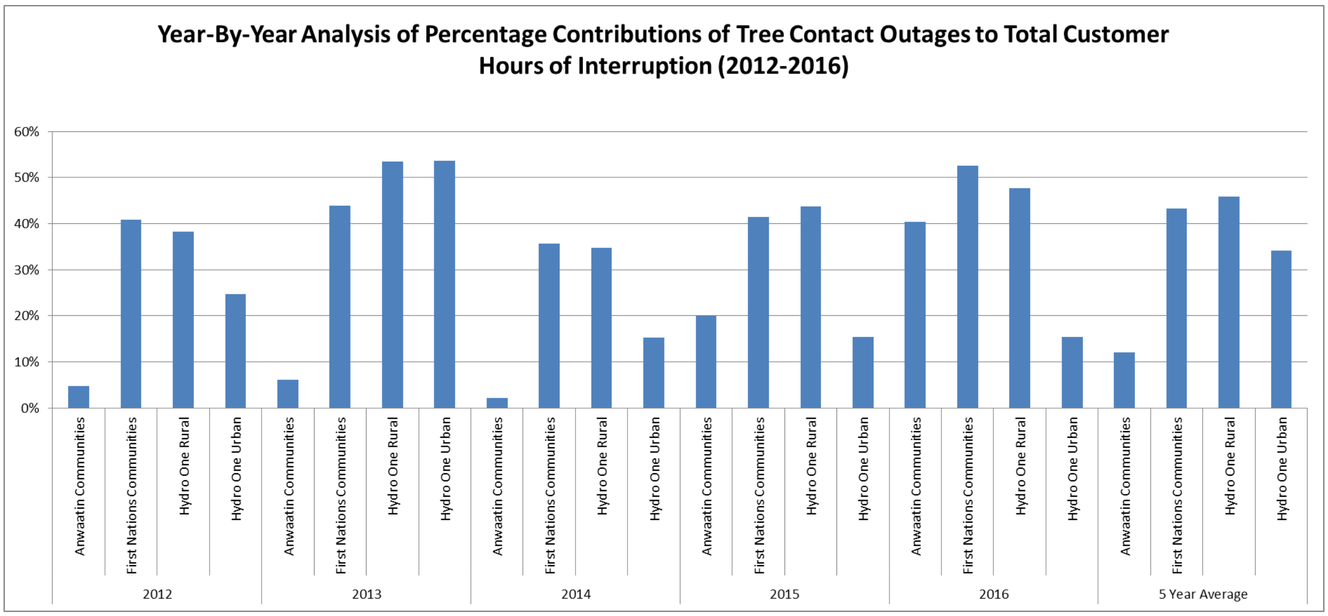


Figure G.1: Percentage Contributions of Tree Contact Outages to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

h) The causes of power failures, excluding Tree Contacts, on the distribution lines and assess are classified as follows:

a. Adverse Environment
b. Defective Equipment
c. Foreign Interference
d. Human Element
e. Loss of Supply
f. Scheduled
g. Unknown/Other

i) Illustrated below are the percentage contributions of each of the causes to the overall customer hours of interruption for First Nations communities (Figure I.1), Anwaatin Communities (Figure I.2), and all of Ontario (Figure I.3).

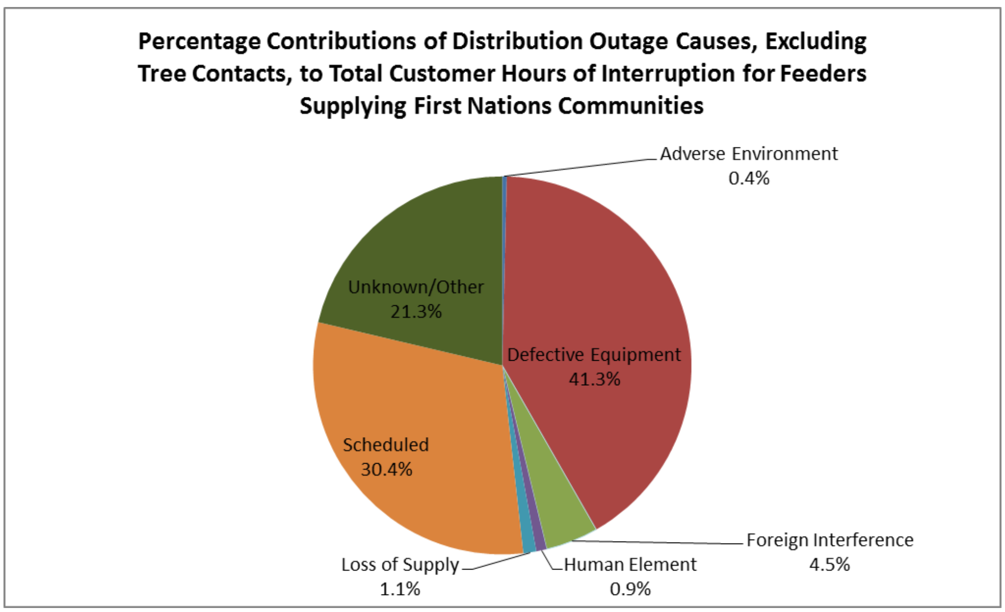


Figure I.1: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

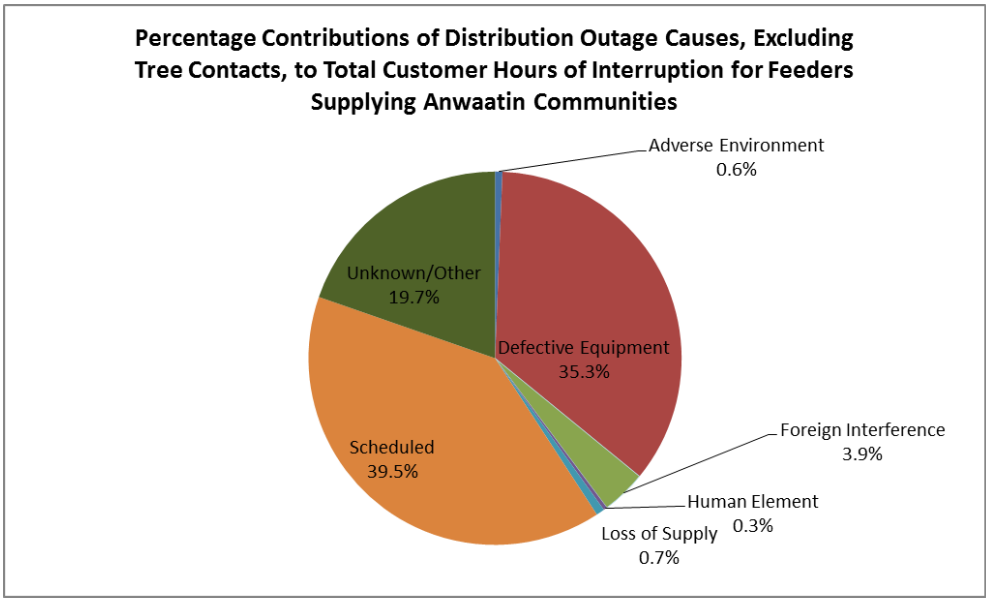


Figure 1.2: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for Feeders Supplying Anwaatin – based on data from 2012-2016

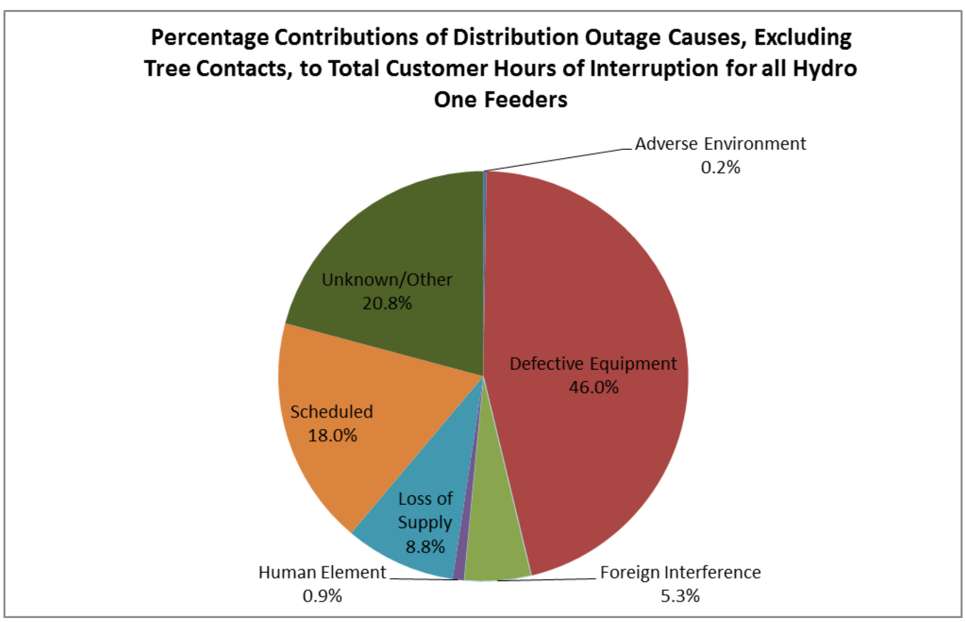


Figure 1.3: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for all Hydro One Feeders – based on data from 2012-2016

HYDRO ONE NETWORKS INC. TRANSMISSION SYSTEM & HIGH VOLTAGE STATIONS - NORTHERN ONTARIO -

Hydro Assets:

High Voltage Transmission Stations
Stations by Voltage

- 115 kV
- 230 kV
- 500 kV

High Voltage Transmission Lines
Lines by Voltage

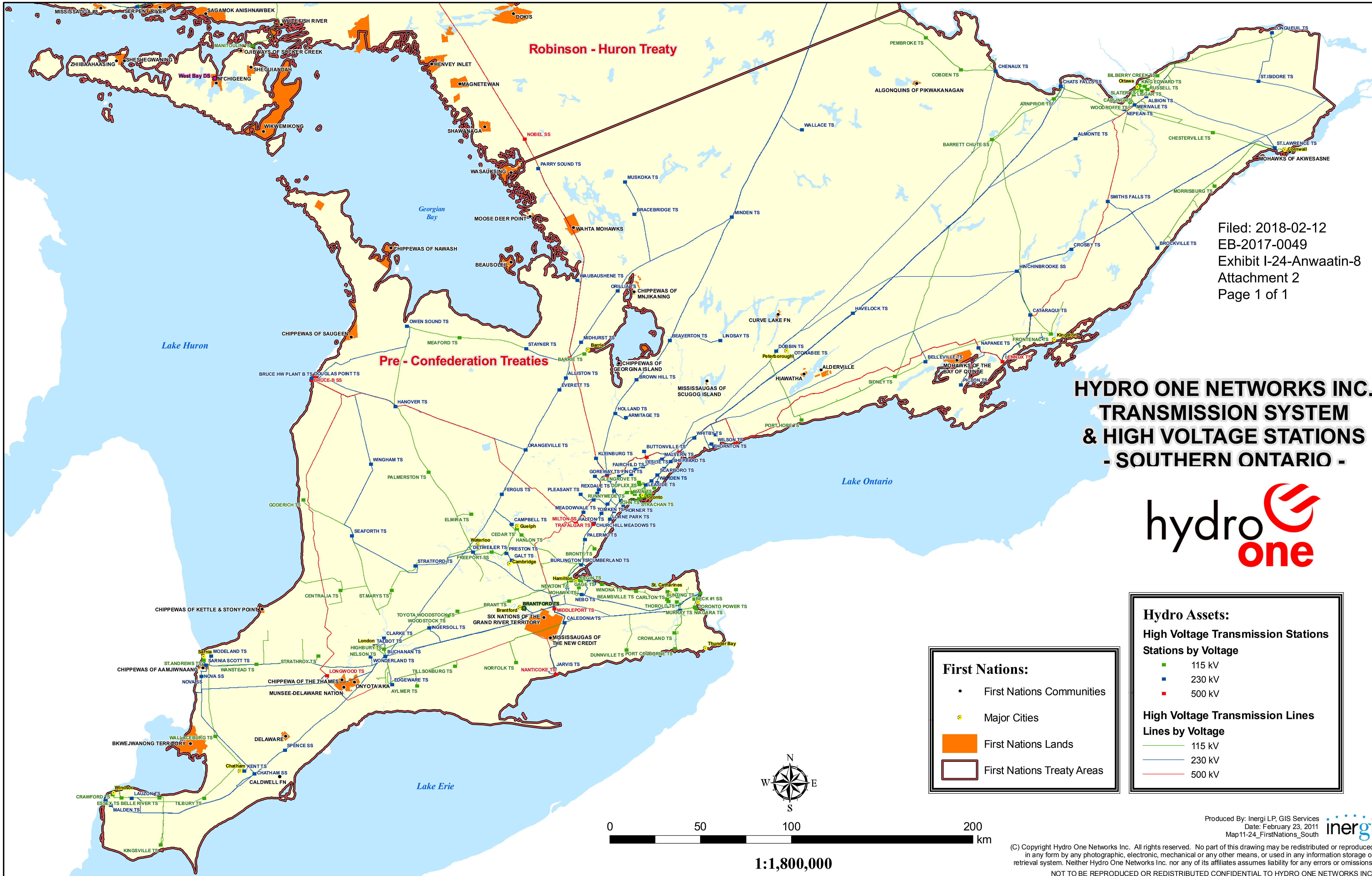
- 115 kV
- 230 kV
- 500 kV

First Nations:

- First Nations Communities
- Remote Communities
- Major Cities
- First Nations Lands
- First Nations Treaty Areas

Produced By: Inergi LP, GIS Services
Date: February 23, 2011
Map11-24_FirstNations_North

Filed: 2018-02-12
EB-2017-0049
Exhibit I-24-Anwaatin-8
Attachment 2
Page 1 of 1



Community	Supply Station	Feeder	Average Pole Age	Pole Count	GOOD	FAIR	POOR	Project	I/S Date
Alderville First Nation	Bowmanton DS	F2	41	665	563	22	80		
Alderville First Nation	Roseneath DS	F1	39	482	422	33	27		
Alderville First Nation	Roseneath DS	F3	42	1025	929	69	27		
Big Grassy First Nation	Sleeman DS	F4	42	2389	2089	270	30		
Chippewas of Nawash Unceded First Nation	Colpoys Bay DS	F3	45	2836	2053	738	45		
Constance Lake First Nation	Calstock DS	F2	35	335	64	269	2		
Couchiching First Nation	Burleigh DS	F1	30	726	592	113	21		
Wahta Mohawks First Nation	Bala River DS	F1	41	1902	263	832	807	WPF	2018/2019
Wahta Mohawks First Nation	Footes Bay DS	F1	39	1664	1524	122	18		
Wahta Mohawks First Nation	Footes Bay DS	F2	44	1281	1226	38	17		
Pic River First Nation (Biigtigong Nishnaabeg First Nation)	Pic DS	F2	32	1512	1335	73	104		
Lac Seul First Nation	Sam Lake DS	F1	26	711	568	128	15		
Magnetawan First Nation	Pointe Au Baril DS	F1	44	2361	1831	357	173		
Rainy River First Nation	Barwick DS	F1	35	1564	1367	174	23		
Moose Deer Point First Nation	Footes Bay DS	F2	44	1281	1226	38	17		
Anishinaabeg of Naongashiing	Sleeman DS	F4	42	2389	2089	270	30		
Eagle Lake	Eton DS	F3	27	1869	1709	125	35		
Asubspeeschoseewagong Netum Anishinabek (Grassy Narrows)	Margach DS	F2	27	2524	2130	319	75		
Lac La Croix	Crilly DS	F1	30	2103	2003	69	31		
Nipissing First Nation	Sturgeon Falls DS	F1	35	833	720	82	31		
Nipissing First Nation	Sturgeon Falls DS	F2	35	800	693	51	56		
Animakee Wa Zhing #37	Sioux Narrows DS	F2	37	833	766	54	13		
Ojibways of Onigaming First Nation	Nestor Falls DS	F2	36	923	722	167	34		
Mishkeegogamang	Crow River DS	F1	21	964	927	35	2		
Mishkeegogamang	Crow River DS	F2	35	454	411	37	6		
Wasauksing First Nation	McGowan Lake DS	F1	44	2314	1913	274	127		
Pays Plat	Schreiber Winnipeg DS	F1	31	1367	1273	68	26		
Naicatchewenin	Devlin DS	F1	41	1316	1174	109	33		
Nigigoonsiminikaaning First Nation	Burleigh DS	F2	35	1210	997	157	56		
Biinjitiwaabik Zaaging Anishinaabek (BZA) aka Rocky Bay First Nation	Beardmore DS #2	F4	30	860	734	96	30		
Mississaugas of Scugog Island First Nation	Scugog Island DS	F2	36	348	318	9	21		
Mississaugas of Scugog Island First Nation	Scugog Island DS	F3	40	399	390	9	0		
Seine River First Nation	Crilly DS	F1	30	2103	2003	69	31		
Iskatewizaagegan #39 Independent First Nation	Clearwater Bay DS	F1	32	1265	1038	146	81		
Shoal Lake No. 40	Clearwater Bay DS	F1	32	1265	1038	146	81		
Slate Falls First Nation	Slate Falls DS	F1	24	198	195	3	0		
Sagamok Anishnawbek	Massey DS	F3	40	2668	2050	590	28		
Mohawks of the Bay of Quinte	Deseronto DS	F1	32	187	113	69	5		
Mohawks of the Bay of Quinte	Shannonville DS	F2	35	821	748	72	1		
Mohawks of the Bay of Quinte	Marysville DS	F1	32	496	414	67	15		
Mohawks of the Bay of Quinte	Marysville DS	F2	33	2055	1394	325	336		
Mohawks of the Bay of Quinte	Marysville DS	F3	27	1009	851	128	30		
Mohawks of the Bay of Quinte	Beechwood DS	F1	32	404	327	46	31		
Wabaseemoong Independent Nations	Whitedog DS	F1	24	369	303	47	19		

Wabigoon Lake Ojibway Nation	Dryden Rural DS	F2	38	2268	1478	665	125		
Obashkaandagaang	Keewatin DS	F2	29	1326	1137	144	45		
Naotkamegwanning	Sioux Narrows DS	F1	35	862	770	87	5		
Naotkamegwanning	Sioux Narrows DS	F2	37	833	766	54	13		
Aroland	Nakina DS	F2	30	324	305	16	3		
Brunswick House, Chapleau Cree FN, Chapleau Ojibway FN	Chapleau DS	F4	43	1202	1027	122	53		
Chippewas of The Thames First Nation	Longwood TS	M26	40	946	904	38	4		
Chippewas of The Thames First Nation	Appin DS	F1	47	1796	1752	39	5		
Beausoloeil First Nation	Thunder Beach DS	F2	39	845	594	235	16	WPF	2018/2019
Beausoloeil First Nation	Thunder Beach DS	F3	38	418	95	305	18	WPF	2018/2019
Beausoloeil First Nation	Awenda DS	F1	30	1306	1079	195	32	WPF	2018/2019
Zhiibaahaasing First Nation	Wolsey Lake DS	F1	36	2360	2180	98	82		
Curve Lake First Nation	Buckhorn DS	F3	37	1577	1483	73	21	WPF	2018/2019
Ochiichagwe'babigo'ining First Nation	Kenora DS	F1	31	1811	1473	256	82		
Dokis	Noelville DS	F1	44	1333	1093	218	22	WPF	2018/2019
Chippewas of Georgina Island First Nation	Virginia Beach DS	F2	47	545	517	16	12		
Chippewas of Georgina Island First Nation	Virginia Beach DS	F3	35	727	685	31	11		
Algonquins of Pikwakanagan	Golden Lake DS	F2	35	2193	496	1622	75	WPF	2018/2019
Red Rock (aka Lake Helen First Nation)	Red Rock DS	F2	32	1328	1126	183	19		
Henvey Inlet	Alban DS	F3	41	1409	1381	25	3	WPF	2018/2019
Hiawatha First Nation	Bensfort Bridge DS	F3	40	1179	854	299	26		
Temagami First Nation	Herridge Lake DS	F1	42	543	425	55	63		
Chippewas of Kettle and Stony Point First Nation	Forest Jura DS	F1	34	1540	1193	290	57		
Chippewas of Kettle and Stony Point First Nation	Forest Jura DS	F2	38	1166	777	36	353		
Long Lake No. 58 First Nation	Longlac West DS	F1	34	369	331	28	10		
Ginoogaming First Nation	Longlac East DS	F2	37	258	227	17	14		
Matachewan	Matachewan DS	F2	18	230	182	3	45		
Mattagami	Shiningtree DS	F1	30	2229	1030	1194	5		
Mississauga	North Shore DS	F1	36	1423	1275	105	43		
Mississauga	Blind River DS	F1	39	82	77	4	1		
Mississauga	Striker DS	F1	36	770	708	45	17		
Mississauga	Striker DS	F2	35	1949	1839	81	29		
Pic Mobert	White River DS	F3	25	587	455	11	121		
Moose Cree First Nation	Moosonee DS	F1	30	665	265	351	49		
Moose Cree First Nation	Moosonee DS	F3	33	515	388	67	60		
Delaware Nation	Thamesville North DS	F2	47	1541	1489	46	6		
Munsee-Delaware Nation	Appin DS	F1	47	1796	1752	39	5		
Munsee-Delaware Nation	Longwood TS	M26	40	946	904	38	4		
Mississaugas of The New Credit First Nation	Lythmore DS	F2	33	1095	60	1017	18		
Mississaugas of The New Credit First Nation	Lythmore DS	F3	35	1119	597	496	26		
Mississaugas of The New Credit First Nation	Jarvis TS	M3	31	3399	3276	106	17		
Taykwa Tagmou Nation	Cochrane West DS	F1	47	3602	1185	2335	82		
Northwest Angle No. 33 / Whitefish Bay 33A	Sioux Narrows DS	F2	37	833	766	54	13		
Oneida Nation of the Thames	Southwold DS	F1	37	921	901	12	8		
Oneida Nation of the Thames	Shedden DS	F1	45	2538	2469	56	13		
Stanjikoming/Mitaanjigamiing First Nation	Burleigh DS	F1	30	726	592	113	21		

Chippewas of Rama First Nation	Rama DS	F1	42	650	631	11	8		
Chippewas of Rama First Nation	Orillia TS	M7	26	859	578	240	41		
Anishinabe of Wauzhushk Onigum (Rat Portage)	Margach DS	F1	35	916	809	89	18		
Saugeen First Nation	Elsinore DS	F1	44	1031	639	328	64	WPF	2018/2019
Saugeen First Nation	Elsinore DS	F2	43	748	674	25	49	WPF	2018/2019
Saugeen First Nation	Sauble Beach DS	F1	44	496	453	40	3	WPF	2018/2019
Ojibway Nation of the Saugeen	Valora DS	F1	37	1476	1376	95	5		
Serpent River	Spanish DS	F2	38	1195	1028	147	20		
Shawanaga First Nation	Carling DS	F3	34	770	686	75	9		
Sheguiandah	Little Current DS	F2	39	2314	2087	178	49		
Sheshegwaning	Wolsey Lake DS	F1	36	2360	2180	98	82		
Sheshegwaning	Manitouwaning DS	F1	35	1738	1561	164	13	WPF	2018/2019
Sheshegwaning	West Bay DS	F2	35	1023	612	279	132		
Six Nations of the Grand River	Lythmore DS	F2	33	1095	60	1017	18		
Six Nations of the Grand River	Lythmore DS	F3	35	1119	597	496	26		
Six Nations of the Grand River	Jarvis TS	M3	31	3399	3276	106	17		
Six Nations of the Grand River	Caledonia TS	M3	34	456	36	411	9		
Six Nations of the Grand River	Newport DS	F1	35	1535	677	804	54		
Aundeck-Omni-Kaning	Little Current DS	F2	39	2314	2087	178	49	WPF	2018/2019
Thessalon	Sowerby DS	F2	46	1113	911	170	32		
Wabauskang First Nation	Perrault Falls DS	F1	34	883	685	172	26		
Wahgoshig	Ramore TS	M3	37	1342	1249	62	31		
Wahnapitae	Post Creek DS	F1	19	113	112	1	0		
Walpole Island	Wallaceburg TS	M5	38	2409	2345	61	3		
M'Chigeeng First Nation	West Bay DS	F1	34	695	477	210	8		
M'Chigeeng First Nation	West Bay DS	F2	35	1023	612	279	132		
Whitefish Lake (Atikameksheng Anishnawbek)	Whitefish DS	F2	48	929	841	77	11		
Whitefish River	Birch Island DS	F1	38	1008	732	205	71	WPF	2018/2019
Whitefish River	Birch Island DS	F2	33	834	703	103	28	WPF	2018/2019
Wikwemikong	Manitouwaning DS	F1	35	1738	1561	164	13		
Wikwemikong	Wolsey Lake DS	F2	34	697	611	60	26		
Caldwell First Nation	Kingsville TS	M1	44	2224	2126	93	5		
Animbigoo Zaagiigan Anishinaabek (AZA)	Jellicoe DS #3	F1	26	440	428	11	1		
MoCreebec Eeyoud aka Moose Cree FN	Moosonee DS	F1	30	665	265	351	49		

WPF = Worst Performing Feeder Investment

Refer to ISD: SR-06 for a list of Station Refurbishment Investments

Building Owners and Managers Association Toronto Interrogatory # 33

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?

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

A-03-01-01 Page: 19

Interrogatory:

a) Are the productivity improvements already included in the applicant's capital and OM&A budget, or are they incremental to those numbers? Please explain fully.

b) Will each initiative be measured against budgeted savings, and how will this be reported to the Board and intervenors each year?

c) p20 – What were the 2017 savings achieved by third party reductions?

d) p19 – Please provide an explanation of the lines under capital in the table, and what the initial two lines mean. How are these numbers, operational and procurement, 11.3 and 14.2 million, respectively, in 2018, differ from the capital and OM&A numbers for 2018?

e) Please show the most recent forecast against the 2017 budget in the table, for all lines for 2017.

f) p20 – Please provide a more detailed description of the pension savings including a copy of the actuary's report as at 2015, and any update as of December 31, 2016.

g) What is meant by "offset by additional renewal cost"?

Witness: LOPEZ Chris

Response:

a) The productivity improvements identified in Exhibit A, Tab 3, Schedule 1, Attachment 1, Distribution Business Plan 2017-2022, p.19 have been updated Exhibit I-25-Staff-123, part a). These savings have been embedded into Hydro One's underlying business plan.

b) Each initiative will be measured against budgeted savings as described in part b) of Exhibit I-25-Staff-123. Hydro One will not be reporting back to the Board and interveners each year on the status of productivity initiatives.

c) Assuming the request is referring to 3rd Party Contract Rate Reductions under the heading 'Information Technology', the 2017 actual results are not yet available, however the forecast year end savings relative to Distribution is $0.33 million.

d) To provide clarity with respect to the table on page 19, Productivity Improvements in Business Plan 2017-2022:

- The initial two rows titled "Operations" and "Procurement" showing $11.3 million and $14.2 million in 2018 represents the Business unit contributing to the overall capital savings of $25.5 million (third row)

- The rows which are referenced above as 'under capital' (rows 4-7) are the Business Units contributing to the overall OM&A savings of $34.8 million which are totalled on row 8 in the table.

e) Please refer to Exhibit I-26-SEP-003, part a).

f) Please refer to Exhibit A, Schedule 3, Tab 1, Attachment 1, p. 20 for the details related to the pension savings. A copy of the December 31, 2015 Actuarial Valuation is attached. The December 31, 2016 Actuarial Valuation has been filed and can be found at Exhibit C1, Schedule 2, Tab 2, Attachment 1.

g) Based on the exhibit reference noted in the question, Hydro One interprets this question to read as follows: What is meant by "offset by additional reinvestment". The intent of this statement was to highlight that as per the 2017-2022 Distribution Business Plan, capital savings resulting from lower pension costs would be reinvested back into the capital work program by completing more work.

HYDRO ONE INC.

HYDRO ONE PENSION PLAN

Actuarial Valuation as at December 31, 2015

June 9, 2016

Registration Number: 1059104

Willis Towers Watson

Table of Contents

Introduction

Purpose

This report with respect to the Hydro One Pension Plan has been prepared for Hydro One Inc., the plan administrator, and presents the results of the actuarial valuation of the plan as at December 31, 2015.

The principal purposes of the report are:

- to present information on the financial position of the plan on both going concern and solvency bases;
- to review the hypothetical windup status of the plan;
- to provide the basis for employer contributions; and
- to provide certain additional information required for the administration of the plan.

This report outlines the changes in the plan's financial situation since the previous actuarial valuation at December 31, 2013, provides the information and the actuarial opinion required by the *Pension Benefits Act (Ontario)* and Regulation thereto and provides the information required to maintain plan registration under the *Income Tax Act (Canada)* and Regulations thereto.

This report summarizes the results of the actuarial valuation and contains an actuarial opinion as an integral part of the report. Supporting detailed information on the significant terms of engagement, assets, actuarial basis, membership data and plan provisions is contained in the Appendices.

The information contained in this report was prepared for Hydro One Inc., for its internal use and for filing with the Financial Services Commission of Ontario and the Canada Revenue Agency, in connection with the actuarial valuation of the plan prepared by Towers Watson Canada Inc. ("Willis Towers Watson"). This report is not intended, nor necessarily suitable, for other parties or for other purposes. Furthermore, some results in this report are based on assumptions mandated by legislation. These results may not be appropriate for purposes other than those for which they were prepared. Further distribution of all or part of this report to other parties (except where such distribution is required by applicable legislation or except in accordance with our written agreement with Hydro One Inc.) or other use of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

Significant Events Since Previous Actuarial Valuation

Actuarial Basis

Since the previous actuarial valuation, the assumptions used in the solvency and hypothetical windup valuations have been updated to reflect market conditions at the actuarial valuation date as outlined in Appendix D. In addition, there have been changes to the going concern actuarial basis, as outlined in Appendix C.

Plan Provisions

This actuarial valuation reflects the plan provisions as at December 31, 2015 and does not make any provision for the possibility that a change or action (retroactive or otherwise) may be imposed by order of a regulatory body or a court as we were not aware of any definitive events that would require such change or action at the time this actuarial valuation was completed.

Since the previous valuation, there have been changes to the plan provisions as follows:

- Management employees who were not eligible to elect to become a member of the plan by September 30, 2015 are no longer eligible to join the plan.

- Employee contribution rates were changed as outlined in Appendix F.

- Effective January 1, 2018, a temporary bridge benefit has been added for Society represented employees hired on or after November 17, 2005 as outlined in Appendix F.

These changes had no material impact on the valuation results at December 31, 2015.

Legislative and Actuarial Standards Updates

Since the previous actuarial valuation, the *Standards of Practice for Pension Commuted Values* published by the Canadian Institute of Actuaries effective February 1, 2011 were revised, effective February 1, 2014, to provide for updates to the mortality assumption as promulgated from time to time by the Actuarial Standards Board (ASB). On December 4, 2014 and April 27, 2015, the ASB proposed to promulgate the use of the mortality rates underlying the 2014 Canadian Pensioners Mortality Table (CPM2014) combined with the mortality improvement scale CPM Improvement Scale B (CPM-B) for calculations, effective October 1, 2015. The updated mortality rates have been reflected for purposes of the solvency and hypothetical windup valuations.

Subsequent Events

We completed this actuarial valuation on June 9, 2016.

To the best of our knowledge and on the basis of our discussions with Hydro One Inc., no events which would have a material financial effect on the actuarial valuation occurred between the actuarial valuation date and the date this actuarial valuation was completed.

Section 1: Going Concern Financial Position

1.1 Statement of Financial Position

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Going Concern Value of Assets	$ 6,071,094	$ 5,204,378
Actuarial Liability		
Active and disabled members	$ 2,208,495	$ 2,161,286
Retired members and beneficiaries	3,860,866	3,676,923
Terminated vested members	39,400	33,623
Total	$ 6,108,761	$ 5,871,832
Additional voluntary contribution	20	19
Total Actuarial Liability	$ 6,108,781	$ 5,871,851
Actuarial Surplus (Unfunded Actuarial Liability)	$ (37,687)	$ (667,473)
Prior Year Credit Balance	(48,000)	(48,000)
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance	$ (85,687)	$ (715,473)

Comments:

- The financial position of the plan on a going concern basis is determined by comparing the going concern value of assets to the actuarial liability and is a reflection of the assets available for the benefits accrued in respect of credited service prior to the actuarial valuation date assuming the plan continues indefinitely.

- The prior year credit balance is employer contributions made prior to the actuarial valuation date that are in excess of the minimum required and are set aside as a reserve for application towards future contribution requirements.

- The increase in the defined benefit actuarial liability as at December 31, 2015 that would result from a 1% decrease in the assumed liability discount rate is $953,459,000. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

1.2 Reconciliation of Financial Position

(dollar amounts in thousands)

Actuarial surplus (unfunded actuarial liability) as at December, 2013 before prior year credit balance		$ (667,473)
Net special payments		177,330
Application of:		
• Actuarial surplus	$ 0	
• Prior year credit balance	0	0
Expected interest on:		
• Actuarial surplus (unfunded actuarial liability)	$ (79,672)	
• Net special payments	10,360	
• Application of actuarial surplus	0	
• Application of prior year credit balance	0	(69,312)
Plan experience:		
• Investment gains (losses)	$ 483,373	
• Salary and YMPE gains (losses)	24,170	
• Cost-of-living adjustment gains (losses)	16,122	
• Retirement gains (losses)	6,603	
• Withdrawal gains (losses)	(17,534)	
• Mortality gains (losses)	6,360	
• Other miscellaneous sources gains (losses)	(8,185)	510,909
Change in actuarial assumptions		$ 10,859
Change in plan provisions		0
Actuarial surplus (unfunded actuarial liability) as at December 31, 2015 before prior year credit balance		$ (37,687)

Comment:

- Actual contributions do not include amounts which were reported as outstanding contributions at the current actuarial valuation date (nor any applicable interest on such outstanding amounts) but include amounts reported as outstanding contributions at the previous actuarial valuation date and contributed prior to the current actuarial valuation date.

1.3 Reconciliation of Prior Year Credit Balance

(dollar amounts in thousands)

Prior year credit balance as at December 31, 2013		$ 48,000
Actual employer contributions:		
• Defined benefit normal actuarial cost	$ 178,102	
• Going concern amortization payments	177,330	
• Solvency amortization payments	0	
• Transfer deficiency payments	0	
• Prior year credit balance	0	
• Other contributions	0	355,432
Minimum employer contributions required:		
• Defined benefit normal actuarial cost	$ (178,102)	
• Going concern amortization payments	(177,330)	
• Solvency amortization payments	0	
• Transfer deficiency payments	0	
• Other contributions	0	(355,432)
Application against unfunded actuarial liability		0
Prior year credit balance as at December 31, 2015		$ 48,000

Section 2: Solvency and Hypothetical Windup Financial Position

2.1 Statement of Solvency Financial Position

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Solvency Value of Assets		
Market value of assets	$ 6,743,615	$ 5,742,219
Provision for plan windup expenses	(16,859)	(14,356)
Total Solvency Value of Assets	$ 6,726,756	$ 5,727,863
Solvency Liability		
Active and disabled members	$ 2,434,330	$ 2,070,880
Retired members and beneficiaries	3,988,651	3,321,439
Terminated vested members	42,265	30,090
Total	$ 6,465,246	$ 5,422,409
Additional voluntary contribution	20	19
Total Solvency Liability	$ 6,465,266	$ 5,422,428
Solvency Surplus (Unfunded Solvency Liability)	$ 261,490	$ 305,435

Comments:

- The financial position of the plan on a solvency basis is determined by comparing the solvency value of assets to the solvency liability (the actuarial present value of benefits accrued in respect of credited service prior to the actuarial valuation date, calculated as if the plan were wound up on that date).

- The solvency actuarial valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.

- Under an amendment to the Regulation to the *Pension Benefits Act (Ontario)* effective November 26, 1992, the employer had the option to make an election to exclude from the solvency liability any benefits relating to plant closure and permanent layoff. This plan does not have any such benefits.

- In addition, the Regulation permits certain benefits to be excluded from the solvency liability, without requiring the employer to make an election. Pursuant to the directions from the plan administrator, the value of benefits attributable to future indexation of benefits have been excluded from the solvency valuation. The full defined benefit hypothetical windup liability, taking into account the benefits excluded under the Regulation, is $9,545,090,000 as at December 31, 2015.

- The increase in the defined benefit solvency liability as at December 31, 2015 that would result from a 1% decrease in the assumed liability discount rate is $937,161,000. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

2.2 Hypothetical Windup Financial Position

The hypothetical windup valuation results presented in this report are determined under the same scenario used for the solvency valuation.

If the plan were to be wound up on the actuarial valuation date, the hypothetical windup value of assets would be equal to the solvency value of assets. As permitted by the Regulation to the *Pension Benefits Act (Ontario),* the employer has elected to exclude certain benefits from the solvency liability. The full hypothetical windup liability, taking into account all of the benefits excluded under the Regulation, is $9,545,090,000 as at December 31, 2015. Consequently, the hypothetical windup surplus (unfunded hypothetical windup liability) as at the actuarial valuation date is $(2,818,334,000).

2.3 Solvency Incremental Cost

The solvency incremental cost for a given year represents the present value, at the actuarial valuation date, of the expected aggregate change in the defined benefit solvency liability during the year, increased for expected benefit payments during the year. The solvency incremental cost in respect of each year between December 31, 2015 and December 31, 2018, the next valuation date, are derived from the projection of the solvency liability, as follows:

(dollar amounts in thousands)	**2016**	**2017**	**2018**
Projected solvency liability as at beginning of year	$ 6,465,266	$ 6,544,378	$ 6,615,885
Solvency incremental cost for the year[1]	201,022	201,820	206,268
Interest on projected solvency liability, solvency incremental cost and expected benefit payments	188,686	190,970	193,189
Expected benefit payments during year	(310,596)	(321,283)	(330,710)
Projected solvency liability as at end of year	$ 6,544,378	$ 6,615,885	$ 6,684,633

Note:

[1] These amounts are as at the beginning of the year. The solvency incremental cost, adjusted with interest as at December 31, 2015, is $196,132,000 for 2017 and $194,805,000 for 2018.

2.4 Determination of the Statutory Solvency Excess (Statutory Solvency Deficiency)

The minimum funding requirements under the Regulation to the *Pension Benefits Act (Ontario)* are based on the statutory solvency excess (statutory solvency deficiency) as at the actuarial valuation date. In calculating the statutory solvency excess (statutory solvency deficiency), various adjustments can be made to the solvency financial position including:

- recognition of the present value of existing amortization payments, including any going concern amortization payments established at the actuarial valuation date, due to be paid within the periods prescribed by the Regulation;

- smoothing of the asset value by use of an averaging technique;

- adjustment to the solvency liability by use of an averaging technique in determining the discount rate used to value the liabilities; and

- removal of any prior year credit balance from the asset value.

To the extent that there exists a statutory solvency deficiency, after taking account of these adjustments, additional amortization payments must be made. If there is no statutory solvency deficiency, the statutory solvency excess may be used to reduce the period of any existing solvency amortization payments.

Statutory Solvency Excess (Statutory Solvency Deficiency)

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Solvency surplus (unfunded solvency liability)	$ 261,490	$ 305,435
Adjustments to solvency position:		
• Present value of existing amortization payments	$ 41,929	$ 404,773
• Smoothing of asset value	(672,521)	(537,841)
• Averaging of liability discount rate	345,438	(20,130)
• Prior year credit balance	(48,000)	(48,000)
• Total	$ (333,154)	$ (201,198)
Statutory solvency excess (statutory solvency deficiency)	$ (71,664)	$ 104,237

Comments:

- Further details on the present value of existing amortization payments at December 31, 2015 are provided below.

Details of Present Value of Existing Amortization Payments

(dollar amounts in thousands)

Type of payment	Effective date	Month of last payment recognized in calculation	Annual amortization payment	Present value as at December 31, 2015 (at 3.40% per annum)
Going Concern	Dec. 31, 2013	Dec. 2021	$ 9,119	$ 41,929

Section 3: Contribution Requirements

3.1 Contributions for Current Service (Ensuing Year)

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Employer Normal Actuarial Cost		
Estimated contribution	$ 85,632	$ 84,818
Estimated payroll	578,543	523,045
% of payroll	14.8%	16.2%
Estimated Member Contributions	$ 45,183	$ 34,798

Comments:

- The employer defined benefit normal actuarial cost rate changed by (1.3)% of payroll due to the changes in membership profile, by 1.0% of payroll due to changes in actuarial basis and by (1.1)% of payroll due to changes in the plan provisions since the previous actuarial valuation.

- The increase in the employer defined benefit normal actuarial cost rate between the actuarial valuation date and the next actuarial valuation date that would result from a 1% decrease in the assumed liability discount rate, is 7.2% of payroll. For purposes of this calculation, no changes were made to any of the other actuarial assumptions or actuarial methods.

3.2 Contributions for Past Service

Going Concern Amortization Payments

The unfunded actuarial liability, adjusted for the prior year credit balance, is $85,687,000. The going concern amortization payments from the previous actuarial valuation have been eliminated or reduced such that the present value of the remaining payment schedule is equal to the unfunded actuarial liability. The unfunded actuarial liability must be liquidated by employer amortization payments at least equal to the amounts, payable monthly in arrears, and for the periods set forth below in order to comply with the Regulation to the *Pension Benefits Act (Ontario).*

(dollar amounts in thousands)

Effective date	Month of last payment	Annual amortization payment	Present value as at December 31, 2015 (at 5.40% per annum)
Dec. 31, 2013	Dec. 2028	$ 9,119	$ 85,687

Solvency Amortization Payments

The statutory solvency deficiency revealed at this actuarial valuation is $71,664,000. This statutory solvency deficiency must be liquidated by employer amortization payments at least equal to the amounts, payable monthly in arrears, and for the periods set forth below in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

(dollar amounts in thousands)

Effective date	Month of last payment	Annual amortization payment	Present value as at December 31, 2015 (at 3.40% per annum)
Dec. 31, 2015	Dec. 2020	$ 15,586	$ 71,664

The employer may establish a letter of credit in order to cover all of or a portion of the above amortization payments, to the extent the letter(s) of credit does not exceed 15% of the solvency liabilities.

3.3 Estimated Minimum Employer Contribution (Ensuing Year)

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Employer Normal Actuarial Cost	$ 85,632	$ 84,818
Amortization Payments		
Going concern	$ 9,119	$ 88,665
Solvency	15,586	0
Total	$ 24,705	$ 88,665
Estimated Minimum Employer Contribution[1]	$ 110,337	$ 173,483

Note:

1 Prior to any application of the prior year credit balance.

3.4 Estimated Maximum Employer Contribution (Ensuing Year)

(dollar amounts in thousands)	**December 31, 2015**	**December 31, 2013**
Employer Normal Actuarial Cost	$ 85,632	$ 84,818
Greater of the Unfunded Actuarial Liability and the Unfunded Hypothetical Windup Liability	2,818,334	2,617,669
Estimated Maximum Employer Contribution	$ 2,903,966	$ 2,702,487

Comment:

- The *Income Tax Act (Canada)* permits the employer to make contributions up to the above amount less the amortization payments made in respect of periods since December 31, 2015, provided that all assumptions made for the purposes of the hypothetical windup valuation remain reasonable at the time each contribution is made. In addition, the maximum employer contribution is to be adjusted with interest for the period between the actuarial valuation date and the date each contribution is made.

3.5 Timing of Contributions

To satisfy the requirements of Ontario pension legislation, the employer normal actuarial cost must be paid monthly and within 30 days of the month to which it pertains while the amortization payments must also be paid monthly but within the period to which they are applicable. Members' contributions must be remitted to the fund monthly and within 30 days of the month to which they pertain.

In addition, within 60 days after this report is filed with the Financial Services Commission of Ontario, the employer must make a special contribution equal to the excess, if any, of:

- the amount of employer contributions (employer normal actuarial cost and amortization payments) that should have been paid after December 31, 2015 according to the minimum contribution requirements revealed by this report (determined with regard to any reported prior year credit balance available to meet these minimum contribution requirements), over

- the actual amount of employer contributions made in respect of periods after December 31, 2015.

Interest must be added to this excess, with such interest determined by reference to the going concern discount rate for payments in respect of employer normal actuarial cost or going concern amortization payments and the solvency discount rate for payments in respect of solvency amortization payments.

To satisfy the requirements of the *Income Tax Act (Canada)*, employer contributions that are remitted to the plan in the taxation year or within 120 days after the end of such taxation year are deductible in such taxation year provided they were made to fund benefits in respect of periods preceding the end of the taxation year.

3.6 Other Statutory Contributions

Additional contributions may be required in respect of the transfer values for members who terminate employment or active plan membership. Where applicable, such additional contributions must be remitted before the related transfer value may be paid in full to the terminated member. Details are provided in Appendix G.

3.7 Future Contribution Levels

Future contribution levels may change as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which have been anticipated at this time. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

Section 4: Actuarial Certification and Opinion

4.1 Actuarial Certification

Based on the results of these actuarial valuations, we hereby certify that, in our opinion, as at December 31, 2015:

- The plan has a prior year credit balance of $48,000,000. The employer may use this prior year credit balance to meet the future contribution requirements of the plan.

- The actuarial surplus (unfunded actuarial liability), determined by comparing the actuarial liability, the measure of obligations of the plan on a going concern basis, to the going concern value of assets, is $(37,687,000).

- The unfunded actuarial liability, adjusted for the prior year credit balance, is $85,687,000 and must be liquidated by employer amortization payments at least equal to the amounts and for the periods set forth in Section 3 in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

- The solvency surplus (unfunded solvency liability), determined by comparing the solvency liability, as defined in the Regulation to the *Pension Benefits Act (Ontario)*, to the solvency value of assets, is $261,490,000.

- The statutory solvency excess (statutory solvency deficiency) revealed at this actuarial valuation is $(71,664,000). This statutory solvency deficiency must be liquidated by employer amortization payments at least equal to the amounts and for the periods set forth in Section 3 in order to comply with the Regulation to the *Pension Benefits Act (Ontario)*.

- The hypothetical windup surplus (unfunded hypothetical windup liability), determined by comparing the hypothetical windup liability, the measure of the obligations of the plan on a hypothetical windup basis including the value of any potential obligations that may have been excluded for purposes of the solvency valuation, to the hypothetical windup value of assets, is $(2,818,334,000).

- The excess actuarial surplus, pursuant to section 147.2(2) of the *Income Tax Act (Canada)*, is $0.

- The rule for computing the employer defined benefit normal actuarial cost is outlined in the table below. Based on the plan membership used for this actuarial valuation (assuming no new entrants) and the scheduled increases in the employee contribution rates disclosed in the summary of plan provisions, the normal actuarial cost for the next three years is estimated to be:

(dollar amounts in thousands)		**2016**	**2017**	**2018**
Estimated employer normal actuarial cost	$	85,632	79,932	77,446
Estimated payroll		578,543	564,507	554,853
% of payroll		14.8%	14.2%	14.0%
Estimated member contributions	$	45,183	47,870	49,267

The employer is required to make normal actuarial cost contributions to the plan in accordance with the above rule until the effective date of the next actuarial opinion.

- The maximum employer contributions permissible under the *Income Tax Act (Canada)* are described in Section 3.

- The transfer ratio, as defined in the Regulation to the *Pension Benefits Act (Ontario)*, is 0.70. The solvency ratio, defined as the ratio of the solvency value of assets prior to deduction of the provision for plan windup expenses to the solvency liabilities, is not less than 1.00.

- The assessment base determined for the Pension Benefits Guarantee Fund (PBGF) is $0. The PBGF liabilities are $6,465,246,000. Additional liabilities for excluded plant closure benefits, in accordance with section 37(4)(a)(ii) of the Regulation to the *Pension Benefits Act (Ontario)*, are $0.

- In accordance with the Regulation to the *Pension Benefits Act (Ontario)*, the next actuarial valuation should be performed with an effective date not later than December 31, 2018. The basis for employer contributions presented in this report is effective until the next actuarial opinion is filed.

4.2 Actuarial Opinion

In our opinion:

- the membership data on which the actuarial valuations are based are sufficient and reliable for the purposes of the going concern, solvency and hypothetical windup valuations,

- the assumptions are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations, and

- the methods employed in the actuarial valuations are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations.

This report has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada. The actuarial valuations have been conducted in accordance with our understanding of the funding and solvency standards prescribed by the *Pension Benefits Act (Ontario)* and Regulation thereto, and in accordance with our understanding of the requirements of the *Income Tax Act (Canada)* and Regulations thereto. This actuarial opinion forms an integral part of the report.

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

Towers Watson Canada Inc.

David Kenny

David Kenny
Fellow of the Canadian Institute of Actuaries

Suzanne Jacques

Suzanne Jacques
Fellow of the Canadian Institute of Actuaries

Toronto, Ontario
June 9, 2016

Appendix A: Significant Terms of Engagement

For purposes of preparing this actuarial valuation report, the plan administrator has directed that:

- The actuarial valuation is to be prepared as at December 31, 2015.
- For purposes of the going concern valuation, the terms of engagement require the use of the margins for adverse deviations mentioned in Appendix C.
- For purposes of determining the going concern liability discount rate, the target asset class distribution is to be established in accordance with the investment policy dated November 12, 2015, which is the most up to date version. There are no expectations that this asset class distribution will be modified in the future.
- For purposes of determining the going concern financial position of the plan, the going concern value of assets is to be determined using the averaging technique described in the Asset Valuation Method section in Appendix C.
- For purposes of determining the solvency liabilities of the plan, the value of benefits arising from future indexation are to be excluded, as permitted by the Regulation to the *Pension Benefits Act (Ontario)*, without requiring an election from the employer.
- For purposes of determining the statutory solvency financial position of the plan, the asset value and liability discount rates are to be determined using the averaging techniques described in the Asset Valuation Method and Rationale for Actuarial Assumptions sections in Appendix D.
- Since to the best of the knowledge of the plan administrator, there is no partial plan windup with an effective date prior to the date of this actuarial valuation, involving members employed in Ontario, not yet completed where the partial windup portion of the plan is in a surplus position on the date of this actuarial valuation, this report is to be prepared on the basis that there will be no retroactive changes to previously filed partial windup reports, if any, and neither the applicable pension regulator nor the plan sponsor will order/declare any partial plan windup with an effective date prior to the actuarial valuation date.
- The solvency and hypothetical windup valuation results presented in this report are to be determined under a scenario where the employer continues to operate and certain expenses are paid from the pension fund (consistent with past practice) while the employer pays other plan expenses.

- This report is to be prepared on the basis that the employer is entitled to apply the actuarial surplus, if any, revealed in an actuarial valuation report to meet its contribution requirements under the plan while the plan remains a going concern, to the extent permitted by applicable pension legislation. (This report does not address the disposition of any surplus assets remaining in the event of plan windup.) If an applicable pension regulator or other entity with jurisdiction directs otherwise, certain financial measures contained in this report, including contribution requirements, may be affected.

Should these directions from the plan administrator be amended or withdrawn, Willis Towers Watson reserves the right to amend or withdraw this report.

Appendix B: Assets

Statement of Market Value

(dollar amounts in thousands)	December 31, 2015	December 31, 2013
Total assets	$ 6,745,869	$ 5,743,450
Net additional outstanding amounts:		
• Contributions receivable	$ 0	$ 0
• Benefits payable	(2,254)	(1,231)
• Investment income receivable	0	0
• Total net outstanding amounts	$ (2,254)	$ (1,231)
Total	$ 6,743,615	$ 5,742,219

Comments:

- The invested assets are held by CIBC Mellon under account OHSG10000000.

- The data relating to the invested assets are based on the financial statements issued by KPMG. The data relating to net outstanding amounts were furnished by Hydro One Inc. All such data have been relied upon by Willis Towers Watson following tests of reasonableness with respect to contributions, benefit payments and investment income. However, Willis Towers Watson has not independently audited or verified these data.

Asset Class Distribution

The following table shows the target asset allocation stipulated by the plan's defined benefit component investment policy in respect of various major asset classes and the actual asset allocation as at December 31, 2015.

	Target asset allocation [1]	**Asset allocation as at December 31, 2015** [2]
Canadian equities	12%	12%
Foreign equities	38%	47%
Bonds and debentures	33%	34%
Real estate and infrastructure	10%	1%
Cash and short-term investments	2%	4%
Private Equities	5%	2%
Total	100%	100%

Notes:

1 This information was obtained from the investment policy in effect for the plan as at December 31, 2015. The target asset allocation is expected to remain in effect indefinitely and there are no expectations that the allocation will change in the future.

2 This information was obtained from Hydro One Inc. All such data have been relied upon by Willis Towers Watson and compared against the target asset allocation to assess reasonableness. However, Willis Towers Watson has not independently audited or verified these data.

Reconciliation of Assets

(dollar amounts in thousands)

Assets as at December 31, 2013		$ 5,743,450
Receipts:		
• Contributions:		
– Employer normal actuarial cost	$ 178,102	
– Employer amortization payments	177,330	
– Employer transfer deficiency payments	0	
– Members' current service contributions	74,173	
– Past service contributions	842	
– Reciprocal transfers	267	
– Provision for non-investment expenses	0	$ 430,714
• Investment return, net of investment expenses		1,283,944
• Total receipts		$ 1,714,658
Disbursements:		
• Benefit payments:		
– Pension payments	$ (579,658)	
– Lump sum settlements	(75,173)	
– Other benefit payments	0	$ (654,831)
• Non-investment expenses		(57,408)
• Total disbursements		$ (712,239)
Assets as at December 31, 2015		$ 6,745,869

Comments:

- This reconciliation is based on the financial statements issued by KPMG. All such data have been relied upon by Willis Towers Watson following tests of reasonableness with respect to contributions, benefit payments and investment income. However, Willis Towers Watson has not independently audited or verified these data.

- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2013 to December 31, 2015 is approximately 10.4% per annum.

Development of the Going Concern Value of Assets

(dollar amounts in thousands)	Adjusted Market Value Beginning from: December 31, 2011	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
Adjusted market value as at December 31, 2011	$ 4,693,703				
Net cash flow for 2012	(98,786)				
Assumed investment return (5.5%)	255,473				
Adjusted market value as at December 31, 2012	4,850,390	$ 5,004,546			
Net cash flow for 2013	(126,979)	(126,979)			
Assumed investment return (5.5%)	263,326	271,805			
Adjusted market value as at December 31, 2013	4,986,737	5,149,372	$ 5,743,450		
Net cash flow for 2014	(106,744)	(106,744)	(106,744)		
Assumed investment return (5.8%)	286,179	295,612	330,068		
Adjusted market value as at December 31, 2014	5,166,172	5,338,240	5,966,774	$ 6,311,204	
Net cash flow for 2015	(117,373)	(117,373)	(117,373)	(117,373)	
Assumed investment return (5.8%)	296,282	306,262	342,717	362,695	
Adjusted market value as at December 31, 2015	$ 5,345,081	$ 5,527,129	$ 6,192,118	$ 6,556,545	$ 6,745,869
Going Concern Value of Assets					
Average of the five adjusted market values as at December 31, 2015					$ 6,073,348
Net outstanding amounts					(2,254)
Going concern value of assets as at December 31, 2015					$ 6,071,094

Comments:

- The asset valuation method is described in Appendix C.
- The rate of return earned on the going concern value of assets, net of all expenses, from December 31, 2013 to December 31, 2015 is approximately 10.2% per annum.

Appendix C: Actuarial Basis – Going Concern Valuation

Methods

Asset Valuation Method

The going concern value of assets was calculated as the average of the market value of assets at the valuation date and the four previous years' adjusted market values. To obtain these adjusted market values, the market values at December 31 of each of the four preceding years were accumulated to the valuation date with net cash flow (i.e., contributions less benefit payments) and assumed investment return. Net cash flow was assumed to occur uniformly throughout each year. Assumed investment return for a year was calculated assuming that each year, the assets earned interest at the going concern discount rate in effect for that year. Finally, this 5-year average of adjusted market values was then adjusted for net additional outstanding amounts.

The objective of the asset valuation method is to produce a smoother pattern of going-concern surplus (deficit) and hence a smoother pattern of contributions, consistent with the long-term nature of a going concern valuation.

Such smoothing is achieved by use of an averaging process which systematically recognizes investment returns different from expectations over a five-year period, with 20% recognized at the valuation date and the remainder at a rate of 20% per year. This method will be expected to average periods of outperformance with periods of underperformance.

The expected return of the going concern discount rate has been selected to equal the expected return on the assets over long periods of time, with a margin for adverse deviations. As such, it is anticipated that, on average, the asset valuation method will tend to produce a result that is somewhat less than the market value of assets.

Actuarial Cost Method

The actuarial liability and the normal actuarial cost were calculated using the projected unit credit cost method.

Prospective benefits were calculated for each active and disabled member according to the plan provisions and actuarial assumptions. The actuarial liability was calculated as the actuarial present value of the member's prospective benefits accrued for credited service to date (the benefit accrual method). The calculation of the actuarial present value of the member's prospective benefits reflects additional entitlements which may arise due to the application of the 50% employer cost-sharing rule, and is at least equal to the member's contributions with interest.

The actuarial liability for retired members and beneficiaries and terminated vested members was calculated as the actuarial present value of their respective benefits.

The employer normal cost for each active and disabled member was determined as the excess of the total normal cost over the member’s required contributions. The normal actuarial cost for each active and disabled member was calculated as the actuarial present value of the member's prospective benefits accruing in respect of credited service in the ensuing year, but not less than the member's required contributions. The employer normal actuarial cost for each active and disabled member was determined as the excess of the total normal actuarial cost over the member's required contributions. The normal actuarial cost rate determined by the projected unit credit cost method will be stable over time if the demographic characteristics of the active and disabled members remain stable from actuarial valuation to actuarial valuation. All other things being equal, a population of active and disabled members whose average age increases (decreases) between actuarial valuations will result in an increasing (decreasing) normal actuarial cost rate.

Additional Voluntary Contributions

For the purposes of the going concern valuation, the determination of the actuarial liability for the additional voluntary contributions does not involve the use of an actuarial cost method, nor does it involve actuarial assumptions. By definition, the actuarial liability under the additional voluntary contributions corresponds with the market value of the members' additional voluntary contribution accounts at the actuarial valuation date.

Actuarial Assumptions

	December 31, 2015	December 31, 2013
Economic Assumptions (per annum)		
Liability discount rate	5.40%	5.80%
Rate of salary increase	2.50% plus merit (see table 1)	2.75% plus merit (see table 1)
Escalation of YMPE under Canada/Québec Pension Plan [1]	3.00%	3.25%
Escalation of *Income Tax Act (Canada)* maximum pension limitation [2]	3.00%	3.25%
Rate of inflation	2.00%	2.25%
Interest on members' contributions	2.00%	Same
Demographic Assumptions		
Mortality	95% of the 2014 Private Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Public Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B, not adjusted for pension size
Withdrawal	Service-related rates (see Table 2a)	Age-related rates (see Table 2b)
Retirement/pension commencement	Age and service related rates (see Table 3a)	Age and service related rates (see Table 3b)
Disability rates	Age-related rates (see Table 4)	Same
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	4
Provision for non-investment expenses	None; return on plan assets is net of all expenses	Same

Notes:

[1] The YMPE of $54,900 for 2016 is the starting value for the YMPE projection as at the current actuarial valuation and is indexed starting in 2016.

[2] The *Income Tax Act (Canada)* maximum pension limit of $2,890 per year of service in 2016 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2016.

Table 1 — Salary Increases due to Movement within the Salary Structure

Age	First 4 Years of Employment	Subsequent Years
under 25	7.0%	1.0%
25 – 29	3.0%	1.0%
30 – 34	3.5%	1.5%
35 – 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 – 49	3.5%	1.5%
50 – 54	2.0%	1.5%
55 – 59	2.0%	1.5%
60 & over	2.0%	0.0%

Table 2a — Current Withdrawal Rates

Service (years)	Male & Female
Under 20	0.01
20 and over	0.00

Table 2b — Sample Prior Withdrawal Rates

Age	Male	Female
15 to 25	0.04	0.05
30 to 35	0.02	0.04
40 to 50	0.01	0.03
over 55	0.00	0.00

Table 3a — Current Retirement Rates

Age	Eligible for Unreduced Retirement: Based on points (82 or 85)	Eligible for Unreduced Retirement: 35 years of service and over	Not Eligible for Unreduced Retirement
under 55	0.10	0.30	0.00
55 to 59	0.15	0.30	0.05
60 to 64	0.12	0.30	0.07
65	0.50	0.30	0.20
66 to 69	0.25	0.30	0.15
70 and over	1.00	1.00	1.00

Table 3b — Prior Retirement Rates

Age	Eligible for Unreduced Retirement	Not Eligible for Unreduced Retirement: Male	Not Eligible for Unreduced Retirement: Female
under 55	0.15	0.00	0.00
55 to 60	0.25	0.02	0.05
61 to 64	0.25	0.07	0.10
65	1.00	1.00	1.00

Table 4 — Disability Rates

Age	Male and Female
under 30	0%
30 to 35	0.105%
35 to 40	0.110%
40 to 45	0.115%
45 to 50	0.120%
50 to 55	0.295%
55 to 59	1.000%
60 and above	1.878%

Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the going concern valuation is summarized below.

The going concern assumptions do not include margins for adverse deviations, except as noted below.

Liability discount rate

Actuarial valuation economic assumptions used for establishing the liability discount rate have been developed based on Willis Towers Watson's capital market model. The capital market model simulates economic variables (e.g. inflation and yields) and asset class returns, with the assumptions being developed through both the analysis of historical rates and returns, and the application of econometric theory. In modeling inflation and bond yields, current conditions and long term expectations are used and the serial correlation inherent in these parameters is recognized.

Our long term nominal rate of return assumption was determined using the expected long term asset mix for the plan, which is consistent with the target mix found in the investment policy in effect for the plan as at the actuarial valuation date.

Based on Willis Towers Watson's capital market model, a best estimate long term gross nominal rate of return as of December 31, 2015 of 6.05%. The following adjustments were subsequently made before selecting the discount rate assumption:

• Best estimate long term nominal rate of return before adjustments	6.05%
• Adjustment for investment expenses paid by the plan (excluding active management fees)	(0.04)
• Adjustment for non-investment expenses paid by the plan	(0.10)
• Best estimate long term nominal rate of return after adjustments	5.91%

In the selection of the discount rate, we have assumed that additional returns associated with employing an active investment management strategy would equal the additional expenses associated with employing such strategy. Consequently, we have disregarded any potential additional returns.

After allowing for a 0.54% margin for adverse deviations, we established the discount rate assumption for the plan as 5.40% (rate is rounded to the nearest 10 basis points).

Rate of salary increase and service

The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 0.50% per annum for the effect of real economic growth and productivity gains in the economy. In addition, an allowance has been made for individual employee merit and promotion based on a scale which varies by age and service as shown in this Appendix C. The merit/promotion assumption is based on discussions with Hydro One Inc. management concerning their future expectations.

Escalation of YMPE under Canada/Québec Pension Plan

The YMPE is indexed annually based on increases in the Industrial Aggregate Wage index for Canada. The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Escalation of Income Tax Act (Canada) maximum pension limitation

The maximum pension limitation under the *Income Tax Act (Canada)* is scheduled to be indexed annually based on assumed increases in the Industrial Aggregate Wage index. The assumption reflects an assumed rate of inflation of 2.00% per annum, plus an allowance of 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Rate of inflation

The assumption reflects an estimate of future rates of inflation considering economic and financial market conditions at the actuarial valuation date. For the current valuation, the assumed inflation rate is 2.00% per annum. This assumption has been updated since the last actuarial valuation (2.25% per annum) to reflect current long term expectation.

Mortality

The 2014 Private Sector Canadian Pensioners' Mortality Table (CPM2014Priv) is based on a mortality experience study for calendar years 1999 to 2008 conducted by the Canadian Institute of Actuaries on a sample of Canadian registered pension plans. The CPM2014Priv table allows for adjustments to the mortality rates based on pension size and/or industry classification. Improvement Scale B (CPM-B) is a two-dimensional scale developed by the Canadian Institute of Actuaries based primarily on the mortality experience of pensioners under the Canada Pension Plan (CPP) and the Québec Pension Plan (QPP) up to 2007 as well as the assumptions used in the 26th CPP Actuarial Report.

Base mortality rates from the CPM2014Priv table, with a multiplier of 95% based on the plan's actual mortality experience are considered reasonable for the actuarial valuation of the plan. Applying improvement scale CPM-B generationally provides an allowance for improvements in mortality after 2014 and is considered reasonable for projecting mortality experience into the future.

At the previous actuarial valuation, the 2014 Public Sector Canadian Pensioners' Mortality Table projected generationally using CPM-B was used. The mortality table was changed as a result of a review of the actual historical mortality of plan members over the period 2007-2015.

Withdrawal

The rates of withdrawal were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations.

The rates of withdrawal at the last actuarial valuation were developed based on a review of plan experience, performed by Mercer (Canada) Limited, for the years 2000 to 2006.

Percentage of involuntary terminations of employment

No allowance has been made for involuntary terminations of employment on the basis that the impact of including such an assumption and valuing statutory grow-in rights would not have a material impact on the actuarial valuation results.

Disability incidence/recovery

The rates of disability incidence/recovery are based on a prior assessment performed by Mercer (Canada) Limited. The use of a different assumption would not have a material impact on the actuarial valuation results.

Retirement from active membership

The rates of retirement were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations. All members are assumed to commence their pension at their retirement date.

The rates of retirement at the last actuarial valuation were developed based on a review of plan experience, performed by Mercer (Canada) Limited, for the years 2000 to 2006.

Pension commencement after termination of employment

All terminated members are assumed to commence their pension at the age that produces the highest liability value based on the plan’s subsidized early retirement reductions applicable to terminated members commencing their pension prior to normal retirement age.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

When provided, the actual data for the spouse and form of payment were used for retired members. For other members, the assumed percentage of members with a spouse is based on the percentages for the general population and an assessment of future expectations for members of the plan.

Years male spouse older than female spouse

When provided, the actual data for the spouse were used for retired members. For other members, the assumption is based on surveys of the age difference in the general population, a review of plan data for the years 2006 to 2015, and an assessment of future expectations for members of the plan.

This assumption has been updated from 4 years at the last valuation to 3 years at the current valuation.

Provision for non-investment expenses

The liability discount rate is net of all expenses. The assumed level of expenses reflected in the liability discount rate is based on recent experience of the plan and an assessment of future expectations.

Appendix D: Actuarial Basis – Solvency and Hypothetical Windup Valuations

Methods

Asset Valuation Method

The market value of assets, adjusted for net outstanding amounts, has been used for the solvency and hypothetical windup valuations. The resulting value has been reduced by a provision for plan windup expenses.

The adjustment in respect of the smoothing of solvency assets for purposes of determining the statutory solvency deficiency was calculated as the difference between the actuarial value of assets used for the going concern valuation and the market value of assets.

Liability Calculation Method

The solvency and hypothetical windup liabilities were calculated using the traditional unit credit cost method.

The solvency and hypothetical windup liabilities for active and disabled members were calculated as the actuarial present value of all benefits accrued up to the actuarial valuation date. This calculation reflects additional entitlements which may arise due to the application of the 50% employer cost-sharing rule, and is at least equal to the member's contributions with interest.

The solvency and hypothetical windup liabilities for retired members and beneficiaries and terminated vested members were calculated as the actuarial present value of their respective benefits.

Other Considerations

The solvency and hypothetical windup valuations have been prepared on a hypothetical basis. In the event of an actual plan windup, the plan assets may have to be allocated between various classes of plan members or beneficiaries as required by applicable pension legislation. Such potential allocation has not been performed as part of these solvency and hypothetical windup valuations.

Additional Voluntary Contribution

For the purposes of the solvency and hypothetical windup valuations, the determination of the liability for the additional voluntary contributions does not involve the use of a liability calculation method, nor does it involve actuarial assumptions. By definition, the solvency and hypothetical windup liability under the additional voluntary contributions corresponds with the market value of the members' additional voluntary contribution accounts at the actuarial valuation date.

Solvency Incremental Cost Actuarial Method

The solvency incremental cost for a given year represents the present value, at the actuarial valuation date, of the expected aggregate change in the defined benefit solvency liability during the year, increased for expected benefit payments during the year.

The solvency incremental cost reflects expected decrements and related changes in membership status, accrual of service, any expected changes in benefits, entitlements, members' contributions, pension formula or increases in the maximum pension limits, and projected pensionable earnings during the year.

The solvency incremental cost has been calculated for each year until the next actuarial valuation date as the projected solvency liability at the end of the year, minus the solvency liability at the beginning of the year, increased for expected benefit payments during the year. Each of these amounts is discounted to the actuarial valuation date using the projected solvency liability discount rate.

The method used to calculate the projected solvency liabilities at each projection year is the same as used in the solvency valuation.

Actuarial Assumptions

	December 31, 2015	December 31, 2013
Economic Assumptions (per annum)		
Liability discount rate (before averaging for solvency and for hypothetical windup)		
• Annuity purchase (non-indexed)	3.10%	3.90%
• Annuity purchase (fully-indexed)	-0.05%	0.15%
• Annuity purchase (partially-indexed) [1]	0.74%	1.10%
• Commuted value (non-indexed)	2.10% for 10 years, 3.70% thereafter	3.00% for 10 years, 4.60% thereafter
• Commuted value (fully-indexed)	1.30% for 10 years, 1.80% thereafter	1.70% for 10 years, 2.30% thereafter
• Commuted value (partially-indexed) [1]	1.50% for 10 years, 2.30% thereafter	2.00% for 10 years, 2.90% thereafter
Liability discount rate (after averaging for solvency)		
• Annuity purchase	3.58%	3.85%
• Commuted value	2.52% for 10 years, 3.96% thereafter	3.08% for 10 years, 4.54% thereafter
Discount rate for determining amortization payments [2]	3.40%	3.70%
Escalation of *Income Tax Act (Canada)* maximum pension limitation [3]	1.16% for 10 years, 2.20% thereafter	1.46% for 10 years, 2.43% thereafter
Demographic Assumptions		
Mortality	CPM2014 Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	1994 Uninsured Pensioner Mortality Table, projected generationally using Scale AA
Withdrawal	N/A	Same
Disability incidence/recovery	N/A	Same
Retirement/pension commencement	Described in detail on page D-8	Same

	December 31, 2015	December 31, 2013
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	4
Percentage of members receiving settlement by commuted value [4]	Retired members and beneficiaries: 0% Other members: ● not eligible for retirement: 70% ● eligible for retirement: 40%	Same
Provision for expenses		
● Solvency	0.25% of assets	Same
● Hypothetical windup	0.25% of assets	Same

Notes:

[1] Applicable to New Society and New Management members only.

[2] Equal to the liability-weighted average of the liability discount rates for settlements by commuted value transfer (rate in effect for the first 10 years) and annuity purchase.

[3] The *Income Tax Act (Canada)* maximum pension limit of $2,890 per year of service in 2016 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2016.

[4] The balance are assumed to receive settlement by annuity purchase.

Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the solvency and hypothetical windup valuations is summarized below.

The actuarial assumptions used in the solvency and hypothetical windup valuations do not include margins for adverse deviations.

Liability discount rate

Discount Rates for Solvency (before averaging) and Hypothetical Windup

In the event of a plan windup, it is expected that a portion of the liabilities will be settled by a group annuity purchase and the balance of the liabilities will be settled by commuted value transfers.

For the calculation of the portion of the solvency and hypothetical windup liabilities relating to the benefits that are expected to be settled by a group annuity purchase, the liability discount rate corresponds to an approximation of the annuity purchase rates as at the actuarial valuation date following application of the relevant guidance on assumptions for solvency and hypothetical windup valuations issued by the Canadian Institute of Actuaries' Committee on Pension Plan Financial Reporting. The guidance provides that the approximation of the annuity purchase rate varies in accordance with the duration of the liabilities for non-indexed benefits assumed to be settled by group annuity. The duration of the liabilities assumed to be settled through the purchase of non-indexed annuities is 11.8.

For the calculation of the portion of the solvency and hypothetical windup liabilities relating to the benefits that are expected to be settled by commuted value transfers, the liability discount rates have been determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the valuation date. For this actuarial valuation, the December 2015 rates have been used.

Discount Rates for Solvency (after averaging)

- The average discount rates for calculation of the statutory solvency deficiency are based on the following: Benefits that are expected to be settled by a group annuity purchase:

  The average of the annualized approximate annuity purchase rates at December 31, 2015 and the four previous year-ends [1], determined as follows:

December 31, 2011	3.79%
December 31, 2012	3.44%
December 31, 2013	4.38%
December 31, 2014	3.18%
December 31, 2015	3.10%
Average	3.58%

Note:

[1] The approximate annuity purchase interest rates prior to October 1, 2015 have been adjusted to reflect the change in the mortality table assumption applicable to the determination of liabilities settled by group annuity purchase.

- Benefits that are expected to be settled by commuted value transfers:

The average of the interest rates determined under the *Standards of Practice for Pension Commuted Values,* published by the Canadian Institute of Actuaries, at December 31, 2015 and the four previous year-ends[1], determined as follows:

	Rate for 10 years	**Rate after 10 years**
December 31, 2011	2.60%	4.10%
December 31, 2012	2.40%	3.60%
December 31, 2013	3.00%	4.60%
December 31, 2014	2.50%	3.80%
December 31, 2015	2.10%	3.70%
Average	2.52%	3.96%

Note:

[1] The *Standards of Practice for Pension Commuted Values* effective on December 31, 2015 are assumed to have always been in effect when determining the interest rates prior to October 1, 2015.

Escalation of Income Tax Act (Canada) maximum pension limitation

The maximum pension limitation under the *Income Tax Act (Canada)* is scheduled to be indexed annually based on assumed increases in the Industrial Aggregate Wage index. This assumption has been determined as the underlying inflation rates from the rates applicable to benefits expected to be settled by commuted value transfers (after averaging for solvency). For simplicity, this assumption has also been used for the benefits that are expected to be settled by a group annuity purchase.

Mortality

For the benefits that are expected to be settled by a group annuity purchase, the assumption has been set following application of the relevant guidance on assumptions for solvency and hypothetical windup valuations issued by the Canadian Institute of Actuaries' Committee on Pension Plan Financial Reporting.

For benefits that are expected to be settled by commuted value transfers, the assumption has been determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the valuation date. No pre-retirement mortality has been assumed in order to approximate the value of pre-retirement death benefits.

Retirement/pension commencement

For active and disabled members:

- Members eligible to retire: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).
- Members with age plus continuous service greater than or equal to 55 years and employed in Ontario or Nova Scotia: pension commences at the age that produces the highest actuarial value of pension (including statutory grow-in rights).
- Other members: pension commences at the age that produces the highest actuarial value

For deferred vested members:

- Members are assumed to retire at the earliest age at which they qualify for an unreduced pension.

For the benefits that are expected to be settled by a group annuity purchase, this is consistent with the expected assumption that will be used by insurers to price the group annuity. For benefits that are expected to be settled by commuted value transfers, this assumption is in accordance with the Canadian Institute of Actuaries' *Standards of Practice for Pension Commuted Values*.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

See rationale for going concern assumptions in Appendix C.

Years male spouse older than female spouse

See rationale for going concern assumptions in Appendix C.

Percentage of members receiving settlement by commuted value transfer

This assumption has been determined by considering the benefit provisions of the plan, legislative requirements to offer specific settlement options to various classes of members, and, in particular, the options to be provided to members upon plan windup.

The assumption also reflects the expectation that members further from retirement are more likely to elect to settle their pension benefit by a commuted value transfer, while members closer to retirement are more likely to elect to settle their pension benefit through a group annuity purchase where this option is available.

Provision for expenses

Allowance was made for normal administrative, actuarial, legal and other costs which would be incurred if the plan were to be wound up (excluding costs relating to the resolution of surplus or deficit issues). The actuarial valuation is premised on a scenario in which the employer continues to operate after the windup date. In establishing the allowance for plan windup costs, certain administrative costs were assumed to be paid from the pension fund (consistent with past practice) while other costs were assumed to be borne directly by the employer.

Solvency Incremental Cost Actuarial Assumptions

Demographic and Benefit Projection Actuarial Assumptions

Except as noted below, the projected population, benefits and members' contributions valued in the solvency liability projection are based on the demographic and benefit projection assumptions used for the going concern valuation described in Appendix C.

New entrants

An allowance has been made for new entrants for the Post-Society and PWU groups only, between the current actuarial valuation date and next actuarial valuation date. The new entrants profile is assumed to be similar to the profile of average new entrants in the plan over the years 2008-2012. We have assumed no new entrants under the management group as new management employees are not entitled to join this plan. Membership in the PWU and Society groups is assumed to remain stable over the projection period.

Solvency Liability Projection Actuarial Assumptions

The solvency liability projections for purposes of calculating the solvency incremental cost are based on the assumptions used for the solvency valuation described previously.

Appendix E: Membership Data

Summary of Membership Data

Active members

	December 31, 2015	December 31, 2013
● Number	5,355	5,360
● Average age	44.1	44.1
● Average credited service	13.3	13.5
● Annual payroll	$ 543,523,888	$ 512,892,395
● Average salary	$ 101,498	$ 95,689
● Accumulated contributions with interest	$ 367,013,623	$ 344,471,267

Disabled Members

	December 31, 2015	December 31, 2013
● Number	131	127
● Average age	54.9	55.4
● Average credited service	23.4	24.3
● Annual payroll	$ 11,169,636	$ 10,152,527
● Average salary	$ 85,264	$ 79,941
● Accumulated contributions with interest	$ 9,230,244	$ 9,175,783

Comment:

- The following distribution relates to active and disabled members. The following meanings have been assigned to age, credited service and earnings:

The following distribution relates to active and disabled members. The following meanings have been assigned to age, credited service and earnings:

- Age — Age as at December 31, 2015
- Credited Service — Credited service as at December 31, 2015
- Earnings — Annual rate of earnings as at December 31, 2015

Active and Disabled Members

		Credited Service								
Age		*0 - 4*	*5 - 9*	*10 - 14*	*15 - 19*	*20 - 24*	*25 - 29*	*30 - 34*	*35 +*	*Total*
< 25	Number	46								46
	Average Earnings	74,940								74,940
25 - 29	Number	415	172							587
	Average Earnings	85,769	90,794							87,241
30 - 34	Number	323	590	32						945
	Average Earnings	88,106	95,815	114,408						93,810
35 - 39	Number	143	335	142	20					640
	Average Earnings	92,827	97,906	107,524	102,732					99,056
40 - 44	Number	78	255	131	34	8	3			509
	Average Earnings	97,414	102,273	105,756	116,031	100,737	98,400			103,297
45 - 49	Number	40	191	97	26	76	146	1		577
	Average Earnings	106,298	102,621	108,600	**	108,667	108,173	**		106,603
50 - 54	Number	46	191	126	46	79	513	97	7	1,105
	Average Earnings	109,043	101,154	106,285	111,880	106,073	108,513	107,856	108,970	106,920
55 - 59	Number	32	116	78	23	43	174	138	75	679
	Average Earnings	92,248	101,065	104,731	127,487	105,011	106,521	115,495	114,327	108,011
60 - 64	Number	12	53	36	24	10	66	50	60	311
	Average Earnings	**	105,610	102,315	109,172	127,285	106,862	100,450	101,895	104,340
65 +	Number	2	16	16	2	3	16	19	13	87
	Average Earnings	**	113,429	98,493	**	171,735	114,443	**	119,733	114,551
Total	Number	1,137	1,919	658	175	219	918	305	155	5,486
	Average Earnings	89,603	98,532	106,592	113,393	108,438	108,033	110,891	109,726	101,111

Average Age = 44.3 Average Credited Service = 13.5

** For confidentiality

Retired members

	December 31, 2015	December 31, 2013
• Number	5,502	5,445
• Average age	71.5	71.1
• Total annual pension	$ 240,389,865	$ 215,558,746
• Average annual pension[1]	$ 43,691	$ 39,588
• Total temporary annual pension	$ 24,642,237	$ 25,163,484

Beneficiaries and survivors

	December 31, 2015	December 31, 2013
• Number	1,777	1,793
• Average age	80.4	79.9
• Total annual pension	$ 44,098,256	$ 41,483,088
• Average annual pension	$ 24,816	$ 23,136
• Total temporary annual pension	$ 460,627	$ 487,347

Terminated vested members

	December 31, 2015	December 31, 2013
• Number	294	292
• Average age	53.5	53.2
• Total annual pension[2]	$ 2,872,957	$ 2,543,201
• Average annual pension	$ 9,772	$ 8,710

Notes:

1 Excluding temporary annual pension.

2 Prior to application of Income Tax Act maximum pension limits.

Review of Membership Data

The membership data were supplied by Hydro One Inc.'s third-party administrator, Morneau Shepell, as at December 31, 2015.

The membership data have been relied upon by Willis Towers Watson following tests for reasonableness and found to be sufficient and reliable for the purposes of the actuarial valuation. Elements of the data review included the following:

- ensuring that the data were intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain whether the complete membership of the plan appeared to be accounted for;
- preparation and review of age and service distributions for active and disabled member for reasonableness;
- review of consistency of individual data items and statistical summaries between the current actuarial valuation and the previous actuarial valuation;
- review of reasonableness of individual data items, statistical summaries and changes in such information since the previous actuarial valuation date; and
- comparison of the membership data and the plan's financial statements for consistency.

However, the tests conducted as part of the membership data review may not have captured certain deficiencies in the data. We have also relied on the certification of the plan administrator as to the quality of the data.

Membership Reconciliation

	Actives	Disabled	Terminated vested	Retired	Beneficiaries and survivors	Total
As at December 31, 2013	5,360	127	292	5,445	1,793	13,017
• New entrants (including re-employed)	485	0	0	0	0	485
• From disabled	6	(6)	0	0	0	0
• To disabled	(34)	34	0	0	0	0
• Terminated (with lump sum payment)	(71)	(2)	(8)	0	0	(81)
• Termination (with vested pension entitlement)	(34)	0	34	0	0	0
• Retirement	(349)	(18)	(22)	389	0	0
• Deceased (without beneficiary)[1]	0	0	0	(148)	(215)	(363)
• Deceased (with beneficiary)	(7)	(4)	0	(184)	195	0
• New ex-spouse	0	0	0	0	4	4
• Data corrections	(1)	0	(2)	0	0	(3)
• Net change	(5)	4	2	57	(16)	42
As at December 31, 2015	5,355	131	294	5,502	1,777	13,059

[1] Includes pensioners whose guarantee period has expired.

Appendix F: Summary of Plan Provisions

The following is an outline of the principal features of the plan which are of financial significance to valuing the plan benefits. This summary is based on the most recently restated plan document as at January 1, 2000 and amendments up to and including the valuation date, as provided by Hydro One Inc., and does not make any provisions for the possibility that a change or action (retroactive or otherwise) could be imposed by order of a regulatory body or a court. It is not a complete description of the plan terms and should not be relied upon for administration or interpretation of benefits. For a detailed description of the benefits, please refer to the plan document.

Membership

The following categories of employees are members of the Pension Plan:

a) All regular employees (see Note 1a and Note 1b);

b) Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982;

c) Continuing construction employees who were members admitted to the Ontario Electricity Financial Corporation Pension Plan and its predecessors;

d) Employees who became continuing construction clerical employees after July 29,1982 and before August 8, 1984;

e) Employees who have completed three months of continuous employment as a probationary employee (see Note 1a and Note 1b).

Note 1a: Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 are eligible after completing three months of continuous employment but are not required to join the Pension Plan.

Note 1b: Management employees who were not eligible to elect to become a member of the Pension Plan on or after September 30, 2015 are no longer eligible to join the Pension Plan.

Any other employee who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the Year’s Maximum Pensionable Earnings (“YMPE”), as defined under the Canada Pension Plan in each of the two previous consecutive calendar years, may elect to become a member of the Pension Plan.

Normal Retirement Date

a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her 65th birthday.

b) All other members: The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

a) 2% of the member's "high three-year average" (see Note 5) for each year of credited service, subject to a maximum of 35 years (see Note 2).

Note 2: For Management employees hired on or after January 1, 2004, and Society represented employees hired on or after November 17, 2005 the reference to "high three-year average" is changed to "high five-year average" for pensionable service while a Management or Society-represented employee.

LESS

b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 5) for each year of credited service included in (a) above subsequent to December 31, 1965, subject to a maximum of 35 years – see Note 3.

Note 3: Effective July 1, 2001, for members of the PWU, and effective January 1, 2004, for Society represented members hired before November 17, 2005; the factor is reduced from 0.625% to 0.50%.

Bridge Pension (see Note 4)

0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 5) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

The bridge benefit is reduced for early retirement in accordance with the same early retirement reduction provision applicable to the early retirement life pension described below.

Note 4: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, no bridge pension is payable for pensionable service *while a Management or Society-represented employee. Effective January 1, 2018, Society represented employees hired on or after November 17, 2005 will be entitled to a bridge benefit equal to 0.625% up to the average YMPE for each year of service from January 1, 2018 onward while the member is earning a benefit under the basic formula.*

Note 5: "High three-year average"/ "high five-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the 36/60 consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the 60 consecutive months when the base earnings were highest.

Early Retirement

<u>Age Plus Service</u> (See Note 7)

A member may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the member's age and years of continuous employment is equal to or greater than 82 or the member has 35 years of continuous employment, whichever occurs first (see Note 6).

Note 6: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, retirement without reduction is available when the sum of the employee's age and years of pensionable service is equal to or greater than 85 or the employee has 35 years of pensionable service, whichever occurs first.

<u>25 or More Years of Continuous Employment</u> (see Note 7)

A member who does not qualify for the early retirement provisions above who is at least age 55 and has 25 or more years of continuous employment may retire prior to age 60, in which case the member's accrued pension is reduced by 3% for each year by which early retirement precedes age 60. These reductions also apply to members who elected a deferred pension when they left the Pension Plan and had 25 or more years of continuous employment.

<u>Female Members with More Than 15 Years or Other Members with 15 or More Years but Less than 25 Years of Continuous Employment</u> (see Note 7)

A female member whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other member with 15 or more years but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the member's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the member's normal retirement date.

These reductions apply with respect to a female member whose employment commenced prior to 1976 and who has a deferred pension and at least 25 years of continuous employment at retirement. For any other members who have a deferred vested pension and have fewer than 25 years of continuous employment and are at least age 55 when they request that the pension payments begin, the deferred vested pension will be actuarially reduced (unless the member was eligible for an unreduced early retirement provision in effect when the member terminated active employment).

Other Members

A member, who does not qualify under any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. If the retirement occurred prior to July 1, 2012, the member is also required to have at least two years of Pension Plan membership. In such a case, the pension is the actuarial equivalent of the member's deferred pension provided that the reduction shall not be less than the minimum early retirement reduction required under the *Income Tax Act* (Canada).

Terminated Members with Deferred Pensions

A terminated member with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination. In addition, if the member's employment is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the *Pension Benefits Act* (Ontario) ("PBA"), resulting in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination.

Note 7: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 all references to "continuous employment" are to be replaced with "pensionable service" for service while a Management or Society-represented employee.

Postponed Retirement

Members who work past their normal retirement date shall continue to accrue benefits until December 1st of the calendar year they reach age 71 (or the Income Tax Act age limit, if different), they reach the 35 year service limit, or they terminate employment, whichever occurs first. If a member reaches 35 years of service and ceases contributions to the Pension Plan, service after 35 years is not counted in the calculation of the member's pension, but the pension is calculated using the member's base earnings up to the date of postponed retirement. If the member works past age 71, the member's pension will commence to be paid not later than December 1st of the year in which the member turns age 71.

Pension Increases

Pension increases of 100% (see Note 8) of the increase in the Consumer Product Index ("CPI") (Ontario), for the 12-month period ending in June of the previous year , will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions to an annual maximum of 8% each year after 1999. Any excess will be carried forward to use in future years up to the 8% limit.

Note 8: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, pension increases of 75% CPI (Ontario) for the 12-month period ending in June of the previous year will be given every January 1, to an annual maximum increase of 5%, with no carry forward.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Employee Contributions

Members, not represented by the Society or PWU, contribute at the following rates until they complete 35 years of credited service:

On and after April 1, 2015,

i. 6.25% of base annual earnings up to the YMPE; and

ii. 8.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired on or after November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 9):

Up to and including March 31, 2016,

i. 6.50% of base annual earnings up to the YMPE; and

ii. 8.50% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

i. 7.00% of base annual earnings up to the YMPE; and

ii. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 7.75% of base annual earnings up to the YMPE; and

ii. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired before November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 9):

Up to and including March 31, 2016,

iii. 6.50% of base annual earnings up to the YMPE; and

iv. 8.50% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

iii. 7.00% of base annual earnings up to the YMPE; and

iv. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

iii. 7.75% of base annual earnings up to the YMPE; and

iv. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018

iii. 8.75% of base annual earnings up to the YMPE; and

iv. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Note 9: For Society represented members hired before November 17, 2005, contributions increase by 0.5% in the event that after January 1, 2004 a valuation report reveals that the solvency assets are lower than 106% of the solvency liabilities. Effective April 1, 2018 this clause is no longer applicable.

Members represented by the PWU contribute at the following rates until they complete 35 years of credited service:

Up to and including March 31, 2016,

i. 7.25% of base annual earnings up to the YMPE; and

ii. 9.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2016,

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 8.75% of base annual earnings up to the YMPE; and

ii. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Death Before Retirement

No Surviving Spouse or Eligible Dependent Children

Fewer than two years of Pension Plan membership (Deaths prior to July 1, 2012)

The member's beneficiary or estate receives a cash refund of the member's contributions plus interest.

Two or more years of Pension Plan membership

The beneficiary or estate will receive the following:

- For pre-1987 service: a cash refund of the member's contributions plus interest.
- For post-1986 service: a lump sum equal to the commuted value of the member's pension earned since 1986, plus a refund of any excess contributions.

For deaths occurring on or after July 1, 2012, the beneficiary or estate will be entitled to the death benefits described above regardless of the member's length of service.

Surviving Spouse (see Note 10)

Fewer than two years of Pension Plan membership and less than 10 years of continuous employment

The beneficiary or estate receives a cash refund of the member's contributions plus interest.

Fewer than two years of Pension Plan membership and more than 10 years of continuous employment

The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned to the date of death.

More than two years of Pension Plan membership, but less than 10 years of continuous employment

For pre-1987 service: The beneficiary or estate receives a cash refund of the member's contributions plus interest.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or
b. an immediate or deferred pension with a commuted value equal to pension earned after 1986.

More than two years of Pension Plan membership, and more than 10 years of continuous employment

For pre-1987 service: The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned prior to 1987.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or

b. an immediate or deferred pension with a commuted value equal to pension earned after 1986. The immediate pension will not be less than 66.67% of the pension earned after 1986.

Note 10: For deaths occurring on or after July 1, 2012, the surviving spouse's entitlement to death benefits for post-1986 service shall be determined without reference to whether the member had more or less than two years of Pension Plan membership. In addition, for deaths occurring on or after July 1, 2012, if the surviving spouse is entitled to the death benefits in respect of the member's post-1986 service, the surviving spouse is also entitled to an amount equal to the member's contributions, with interest, in respect of pre-1987 service, rather than the designated beneficiary or estate.

Dependent Children, No Surviving Spouse

If the member completed 10 years of continuous employment, the survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. A payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, being an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse, subject to other options chosen at the time of retirement. If the survivor spouse subsequently dies and is survived by the dependent children, or the member does not have a surviving spouse and is survived only by dependent children, the 66.67% survivor pension is split among the dependent children and is payable to age 18 (longer if disabled or in full-time attendance at a school or university).

If the member does not have a surviving spouse at retirement, the normal form of pension is a pension payable for life with a guarantee of 60 payments.

Optional forms of pension are available on an actuarially equivalent basis.

Termination of Employment (see Note 12)

Less Than One Year of Pension Plan Membership

A cash refund of the member's contributions plus interest.

More Than One Year But Fewer Than Two Years of Pension Plan Membership

The member is entitled to elect a cash refund of the member's contributions plus interest, or may leave the earned pension benefit in the Pension Plan to be paid upon retirement.

More Than Two Years but fewer than 10 Years of Pension Plan Membership and, either under Age 45, or Fewer Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to a cash refund of the member's contributions plus interest, or may leave all of the earned pension benefit in the Pension Plan until retirement.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More Than Two Years but fewer than 10 Years of Pension Plan Membership, and Age 45 or Older with More Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) 75% of the commuted value of the pension and receive a refund of 25% of the commuted value of your earned pension; or to leave 75% of the earned pension benefit in the Pension Plan until retirement, and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More Than 10 Years of Pension Plan Membership, But Younger Than Age 45

For service from 1965 to 1986: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 11) the commuted value of the earned pension.

More than 10 Years of Pension Plan Membership and Age 45 or Older

For pre-1965 service: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value.

For service from 1965 to 1986: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value; or to transfer (see Note 11) the greater of the commuted value of 75% of the earned pension or the member's contributions with interest and receive a refund of 25% of the commuted value of the earned pension.

For post 1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer the commuted value of the earned pension.

If a member is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the PBA, which could result in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination. If grow-in benefits apply, this may affect the value of the benefits the member is entitled to receive on termination of employment or retirement.

Note 11: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Note 12: In respect of terminations occurring on or after July 1, 2012, a member is entitled to the earned pension benefits for all service regardless of length of Pension Plan membership, continuous employment or age.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the vested deferred pension accrued after 1986 is refunded to the member (or to the spouse, beneficiary or estate, as applicable in the case of death before retirement).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987. (See Note 13)

Note 13: For terminations occurring on or after July 1, 2012, entitlement to excess contributions in respect of pre-1987 service shall be determined without reference to age or years of continuous employment.

Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act (Canada).

Appendix G: PBGF Assessment, Transfer Ratio and Solvency Ratio

PBGF Assessment

(dollar amounts in thousands)		**December 31, 2015**
PBGF Assessment		
Solvency liability:		
• Total	$	6,465,246
• Ontario PBGF liability		6,465,246
• Ontario additional PBGF liability		0
Solvency value of assets:		
• Total	$	6,743,595
• Ontario PBGF assets		6,743,595
PBGF assessment base	$	0
Plan membership (including inactive members):		
• Total		13,059
• Ontario		13,059

Comments:

- The solvency value of assets reflects net outstanding amounts. The solvency value of assets is prior to deduction of a provision for plan windup expenses.
- For the purposes of calculating the PBGF assessment base, the solvency value of assets and the solvency liability exclude the additional voluntary contribution provision.
- The Ontario PBGF liability used for purposes of calculating the PBGF assessment excludes the Ontario additional PBGF liability.
- As specified in the Regulation to the *Pension Benefits Act (Ontario)*, the additional PBGF liability is the additional solvency liability for plant closure and permanent layoff benefits excluded for those Ontario members who are immediately eligible for the benefit at the actuarial valuation date, if any.

Transfer Ratio and Solvency Ratio

(dollar amounts in thousands)		December 31, 2015
Transfer Ratio		
Solvency value of assets	$	6,743,615
Lesser of estimated employer contributions for the period until the next actuarial valuation and prior year credit balance	$	48,000
Hypothetical windup liability	$	9,545,090
Transfer ratio		0.70
Solvency Ratio		
Solvency value of assets	$	6,743,615
Solvency liability	$	6,465,266
Solvency ratio		Not less than 1.00

Comments:

- The solvency value of assets reflects net outstanding amounts. The solvency value of assets is prior to deduction of a provision for plan windup expenses.
- As the transfer ratio is less than 1.00, transfer deficiencies must be paid over a maximum period of five years unless the cumulative transfer deficiencies are within the limits prescribed by the Regulation to the *Pension Benefits Act (Ontario)* or the employer remits additional contributions in respect of the transfer deficiencies. Pursuant to Regulations 19(4) or 19(5) to the *Pension Benefits Act (Ontario)*, approval of the Superintendent will be required to make commuted value transfers if there has been a significant decline in the transfer ratio after the actuarial valuation date.
- Based on the solvency ratio defined as the ratio of solvency value of assets to solvency liabilities, the next actuarial valuation of the plan is due with an effective date not later than December 31, 2018.

Appendix H: Certificate of the Plan Administrator

I hereby certify that to the best of my knowledge and belief:

- the significant terms of engagement contained in Appendix A of this report are accurate and reflect the plan administrator's judgement of the plan provisions and/or an appropriate basis for the actuarial valuation of the plan;
- the information on plan assets, including the information on the investment policy and intended changes to the asset mix distribution after the valuation date, if any, forwarded to Towers Watson Canada Inc. and summarized in Appendix B of this report is complete and accurate;
- the data forwarded to Towers Watson Canada Inc. and summarized in Appendix E of this report are a complete and accurate description of all persons who are members of the plan, including beneficiaries who are in receipt of a retirement income, in respect of service up to the date of the actuarial valuation;
- the summary of plan provisions contained in Appendix F of this report is accurate; and
- there have been no events which occurred between the actuarial valuation date and the date this actuarial valuation was completed that may have a material financial effect on the actuarial valuation.

[signature]	6/6/16
Signature	Date
Michael Vels	Chief Financial Officer
Name	Title

Appendix I: Actuarial Information Summary

Building Owners and Managers Association Toronto Interrogatory # 91

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:

Exhibit B, Tab 1, Schedule 1 Page: 14

Interrogatory:

Please provide a tabular breakdown, comparable to Tables 2 and 3 on p13 of the system record planned expenditures.

Response:

It is unclear what breakdown is being requested in this interrogatory. However, a breakdown of all capital expenditures is available in Section 3.2 of the DSP.

Consumers Council of Canada 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

Interrogatory:

When was the last DSP prepared by HON? Please describe in detail how the preparation of this plan differs from the approach used to develop the previous DSP. When is the next DSP expected to be developed? To what extent does HON coordinate investment planning between its Distribution and Transmission businesses. Do what extent does HON coordinate the prioritization of investments between its Transmission and Distribution businesses?

Response:

The previous Investment Plan was prepared in 2015.

The development of this plan was different from the previous approach in that:

- A formal customer engagement process was carried out and the results informed the planning process; and
- Multiple plan options (Plan A, Plan B, Plan C, Plan B-modified) were considered.

The next DSP is expected to be developed during 2018.

Hydro One does co-ordinate investment planning between distribution and transmission businesses. Hydro One's common (general plant) investments are planned and allocated to either the distribution or transmission businesses or a percentage to both.

Hydro One's distribution and transmission investments are not prioritized against one another as the two businesses are separately regulated entities.

Consumers Council of Canada 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 Section 1.1 Page 19

Interrogatory:

The evidence indicates that the information contained in the DSP is considered current as the end of 2016. The asset information utilized in the report (e.g., condition data and performance data) is based on data as of August 2016 to allow time to process and analyze the information to facilitate preparation of the DSP for this filing.

Response:

This interrogatory does not contain a question.

Consumers Council of Canada Interrogatory # 25

Issue:

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

Reference:

A-03-01 Page 14

Interrogatory:

Please provide all of the materials presented to HON's senior leadership team and Board of Directors regarding the three alternative candidate investment plans. (Plans A, B and C).

Response:

Please refer to the November 2016 Board of Directors Memo and December 2016 Board of Directors documentation provided in Exhibit I- 3-SEC-4.

Consumers Council of Canada Interrogatory # 26

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:

A-03-01 Page 17 and Attachment 1 – p. 15

Interrogatory:

The evidence states that with respect to the Investment Plan Options Modified Plan B included a number of adjustments to the original Plan B. The projected capital expenditures were reduced by $51 million. Please explain how the $51 million was derived. Please reconcile this with the reductions set out on p. 15 of the Business Plan which amount to $65 million. Please explain the process undertaken to determine the reductions in each of the categories listed – IT, Wood Pole Program, Station Refurbishment, Component Replacement Activities, Facilities and Fleet Investment.

Response:

The 2018 reductions totalling $65 million (see page 15 of the Dx Business Plan) are stated in gross dollars and include a combined transmission and distribution total for General Plant investments common to both the transmission and distribution businesses. This corresponds to a combined transmission/distribution net impact of $60 million. The net dollars below reflect gross expenditures less asset removal costs and third party contributions, if applicable. The table below reconciles Plan B to Plan B Modified for year 2018 in gross and net dollars. Reductions were based on identifying investments to minimize near-term rate impacts without a significant impact to reliability. (Please refer to Exhibit I-7-CCC-11 for a variance analysis comparing Plan B and Plan B Modified for the period 2018-2022 in net dollars.)

	2018 Reductions ($M) Original Plan B and Plan B-Mod		
	Dec. Board of Directors Document		
Investment Description	**(Gross $- Tx/Dx)**	**(Net $ - Tx/Dx)**	**Application (Net $ - Dx)**
Transport & Work Equipment (TWE) Capital Requirements	-6	-6	-4
Pole Replacement	-25	-22	-22
Large Sustainment Initiatives	-10	-9	-9
DS Station Refurbishment Program	-15	-14	-14
Dx Facility Accommodation & Improvements	-4	-4	-4
C&I Customers - Demand to Interval	-4	-4	-1
C&I Customers - First Fuel	-1	-1	-2
Immaterial Adjustments over 70+ investments			5
Total	**-65**	**-60**	**-51**

Consumers Council of Canada Interrogatory # 27

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:

None

Interrogatory:

Please provide all HON policies regarding the use of helicopters with respect to the Distribution business. How large is the current fleet of helicopters? What are the annual operating and capital costs associated with the use of helicopters?

Response:

See Attachment 1 - Helicopter Usage Policy for Hydro One's Helicopter Use Procedure.

Currently Hydro One Networks has 7 Helicopters. The annual operating costs are approximately 10 million dollars. Helicopter Services does not have any annual capital expenditures. The replacement or addition of any helicopter in the fleet will be included in the Transport and Work Equipment Capital Replacement Program, shown in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 ISD-GP-01.

Document Number: **SP 0700 R0**

Document Name: **Helicopter Usage Policy**

Issue Date: **April 2007**

When in printed form, this document is uncontrolled.
It is the user's responsibility to verify that this copy matches the document on the Hods website.

The requirements of this document are mandatory.

Purpose

This document communicates the corporate policy which must be adhered to when requesting helicopter support within Hydro One.

Revision

This is a new document.

Contents

1.0 Policy

The Hydro One Code of Business Conduct establishes the policy for the "Proper Use of Assets" (refer to Appendix A). In support of the Code of Business Conduct Fleet Services must ensure that proper authorization is obtained prior to any helicopter usage whether utilizing the internal Hydro One helicopter fleet or an external helicopter operator.

Authorization for helicopter support is required by Director level or higher, or the Manager of Fleet Services or the Manager of Construction Services.

2.0 Request for Helicopter Support

All requests for helicopter support must be channelled through Hydro One Helicopter Services. This will provide assurances that the Hydro One helicopter fleet is utilized prior to the use of an external helicopter operator.

2.1 Requirement for Flight Manifest

A manifest (see Appendix B) is required for all helicopter flights including a listing of passengers by name, department, destination, stops, and reason for flight and includes a signature of authorization, from a Director level or higher, or the Manager of Fleet Services or the Manager of Construction. This manifest will be filled out and given to the pilot prior to the flight. The pilot will confirm the passengers listed are present and amend the manifest identifying any additional passengers that were not listed. The manifest will be attached to the Hydro One Helicopter Services flight report and filed at the main base for a period not less than 2 years.

A manifest is not required for helicopter flights in support of approved work programs for the individual lines of business and when responding to an emergency. Pilots and Crew members must be signed on to the appropriate job plan which includes the work description. Justification for the use of helicopter support is determined by the individual lines of business.

Appendix A: Code of Conduct

<u>REFERENCED SECTION FROM CODE OF BUSINESS CONDUCT BOOKLET</u>

Proper use of assets

We protect the company's assets (fixed and moveable property, personnel, information, intellectual property and commodities), use them properly, safely, efficiently, and only for Hydro One business.

We do not use company assets in a manner that compromises our competitive business practices or offends, harasses, or promotes unacceptable behaviour (improper use of email and Internet).

We protect our assets from theft, fraud, destruction, vandalism or neglect. We dispose of company property in an ethical and approved manner. Internal or employee theft or fraud will not be tolerated.

Any use of company assets for a non-business reason (charitable work, for example) must be approved by the supervisor accountable for that asset. Effective protection of our company assets can enhance our competitive edge.

Appendix B: Flight Manifest

Click to view Helicopter Flight Manifest in pdf format.

Canadian Manufacturers & Exporters Interrogatory # 13

Issue:

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

Reference:

B1-01-01 Section 1.1 Page: 3

Interrogatory:

Hydro One states that it also "considered what would be required to achieve the lowest 2018 rate increase without material disruption to its operations. Presented as the "Plan C" scenario, Hydro One's conclusion was that this option as a whole was not viable due to the estimated degradation of approximately 2% in both SAIDI and SAIFI that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition."

a) How does Hydro One define "material" disruptions to its operations
b) What methodology did Hydro One employ to determine what level of disruptions were material?
c) Does a 2% degradation in SAIDI and SAIFI qualify as being a material disruption to Hydro One's operations?

Response:

a) In this instance, Hydro One defines "material" as having the meaningful potential to impair Hydro One's ability to meet its Business Objectives. This encompasses many considerations, including safety, customers, reliability, environment and financial performance, among others. Furthermore, a "material" disruption would occur if a particular strategy hampered Hydro One's ability to maintain its system over the rate application term and beyond. Please see part c) of Exhibit I-35-BOMA-B031 for reasons why Hydro One determined Plan C was materially disruptive.

b) Please see part c) of Exhibit I-35-BOMA-31.

c) Please see part c) of Exhibit I-35-BOMA-31.

Energy Probe Research Foundation Interrogatory # 32

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 1.1 Page: 3

Interrogatory:

a) Was the Ontario Ministry of Energy consulted or informed of Plan A and Plan B alternatives in the process of reaching the decision on the DSP?

b) Please file all documents including reports and presentations that Hydro One gave to the Ministry of Energy regarding Plan A and Plan B alternatives.

Response:

a) No, Hydro One did not consult or inform the Ministry of Energy of Plans A and B in reaching its decision on the DSP.

b) Not applicable.

Energy Probe Research Foundation Interrogatory # 33

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 1.6 Page: 2

Interrogatory:
Hydro One says it is considering whether to reduce its capitalization policy from $2 million to $500k.

a) Has Hydro One formally reduced its capitalization policy?

b) Please provide any documents, memos or internal studies related to Hydro One's decision to either reduce its capitalization policy or keep it at its current level.

Response:
a) Please refer to Exhibit I-10-Staff-49 part (a).

b) The change in capitalization threshold is not a change in policy; it is a change in threshold. The Company used a benchmarking survey performed through the Edison Electric Institute to assist with the establishment of a reasonable threshold. This survey was completed by 15 companies in our industry including Hydro One. For confidentiality purposes, the names of the companies that participated in the survey, are not displayed in the results below:

Q: Do you have a materiality limit for capitalizing software costs? If yes, what is the dollar value (or useful life threshold used)?

Company 2	At least $100,000.00 with a minimum of at least one year of useful life.
Company 3	Our capitalization threshold for software is $250,000 in most cases
Company 4	$50,000
Company 5	$100k, has to be a long lived asset (no life is spelled out but generally 3 years and greater are capitalized)
Company 6	Yes, $100,000 or greater
Company 7	Purchased Software licenses in excess of $10K with an expected useful life of more than one year or internally developed software projects above $100K with a useful life greater than 1 year.
Company 8	$ 1000 for application software (must have utility for > 1 year) and internally developed software follows ASC 350-40 and threshold is $10,000
Company 9	$5K for commercial off the shelf and $50K for internally developed software
Company 10	$500 K
Company 11	Yes, $100k
Company 12	$50,000
Company 13	Yes, we have a $1M capitalization threshold for capitalizing software costs.
Company 14	Yes - $50k is our threshold
Company 15	Yes, $15,000 - w/5 year life

Energy Probe Research Foundation Interrogatory # 34

Issue:

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

Reference:

B1-01-01 Section 1.4 Page: 21-27

Interrogatory:

Please breakdown the reliability data – SAIDA, SAIFI and CAIDI by rate class (UR, RI and R2).

Response:

Table 1 - Historical Urban SAIDI Summary

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

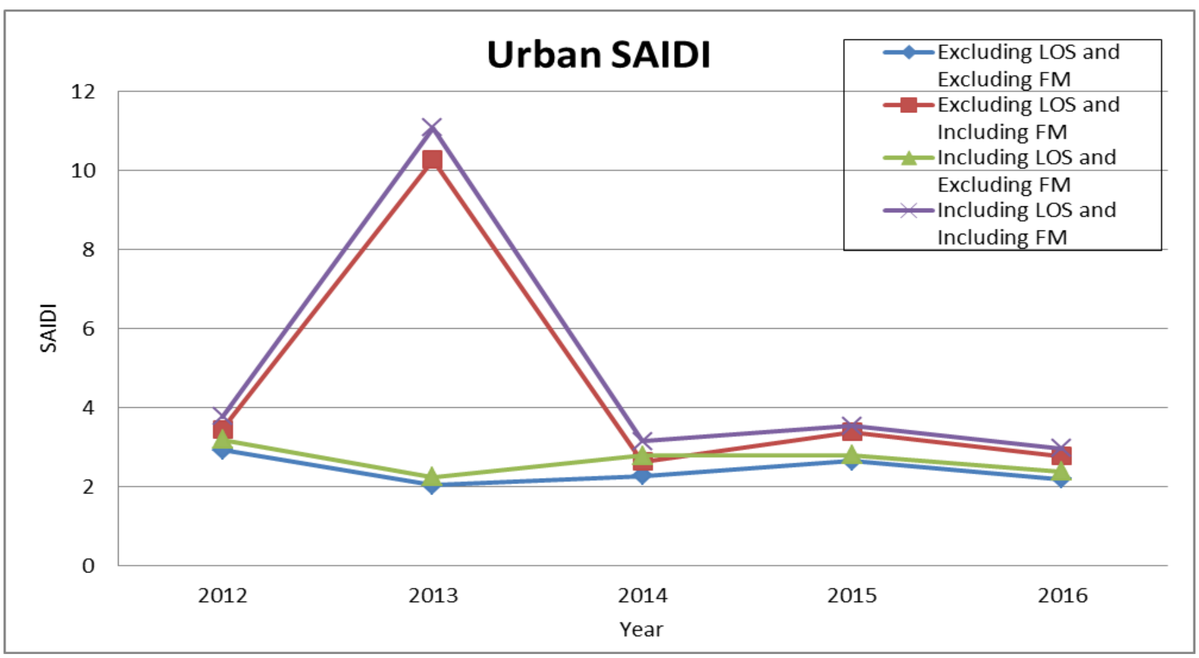


Figure 1 – Chart of Historical Urban SAIDI

]Table 2 - Historical Urban SAIFI Summary

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

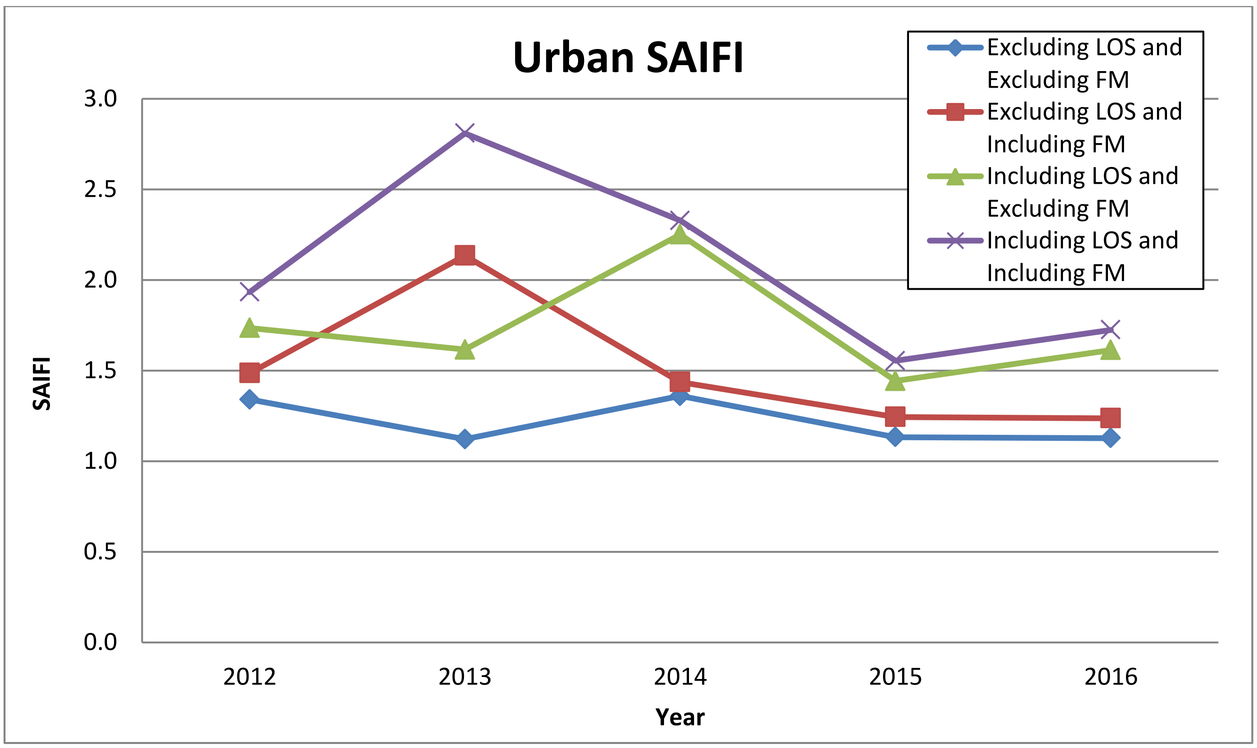


Figure 2 – Chart of Historical Urban SAIFI

Table 3 - Historical Urban CAIDI Summary

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

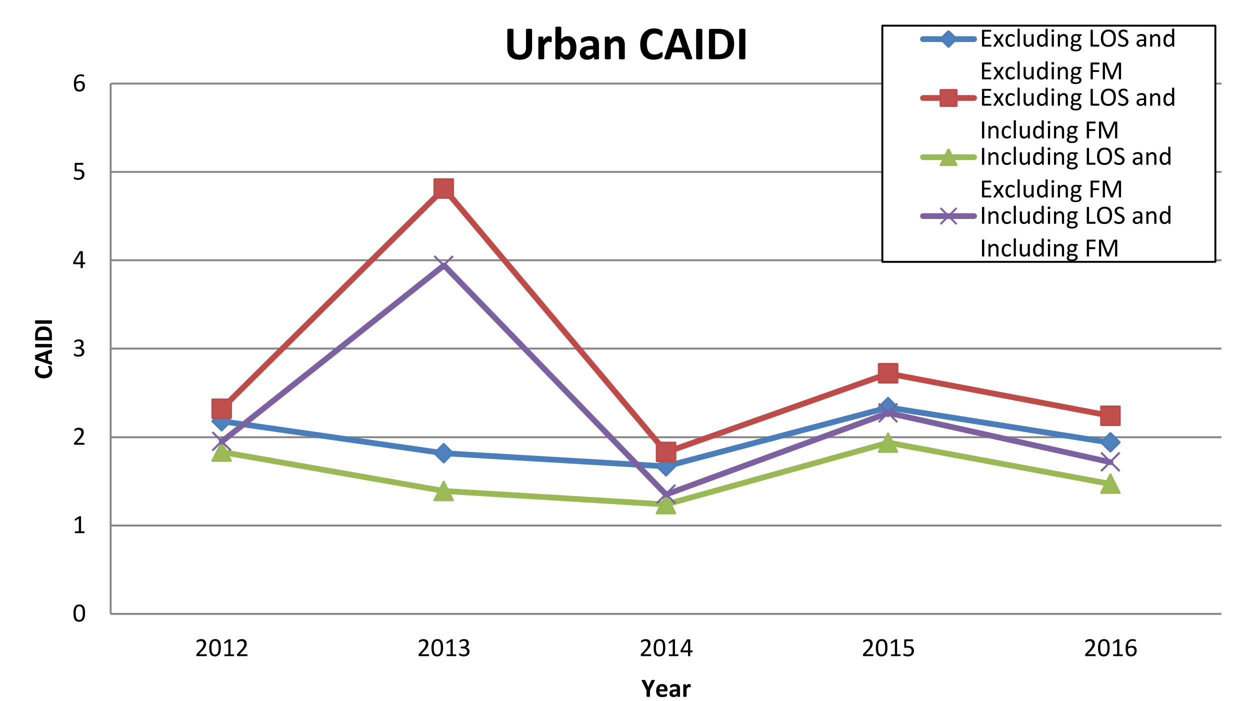


Figure 3 – Chart of Historical Urban CAIDI

Table 4 - Historical Rural SAIDI Summary

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

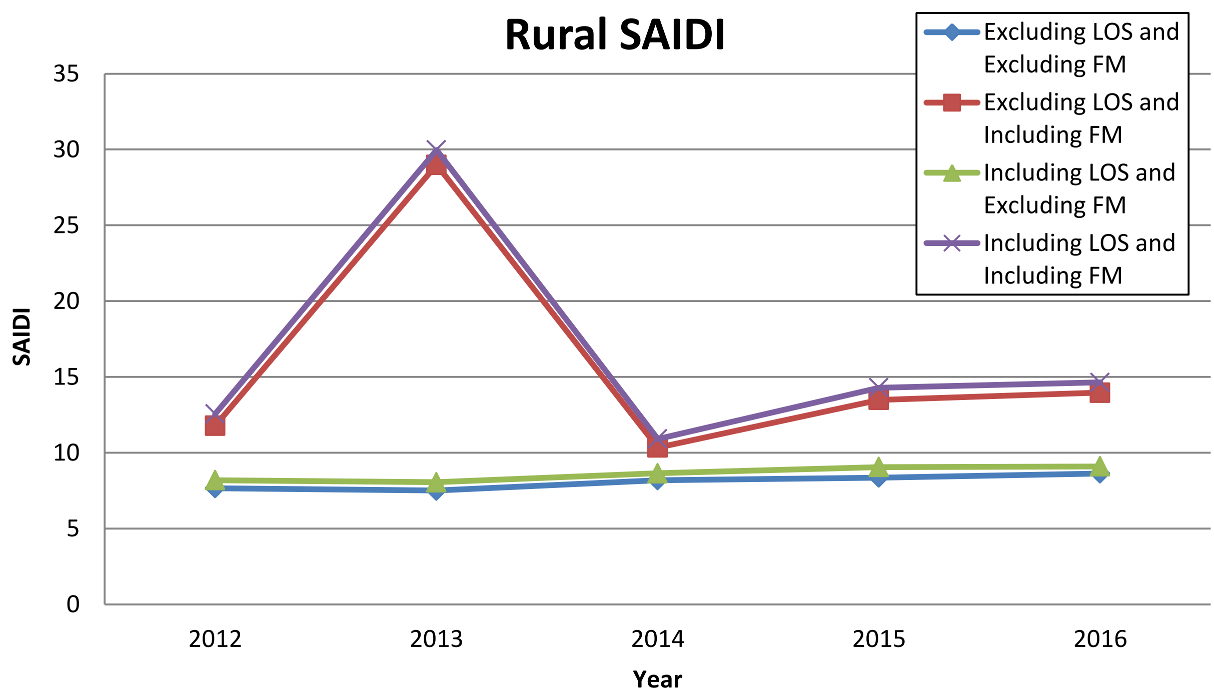


Figure 4 – Chart of Historical Rural SAIDI

Table 5 - Historical Rural SAIFI Summary

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

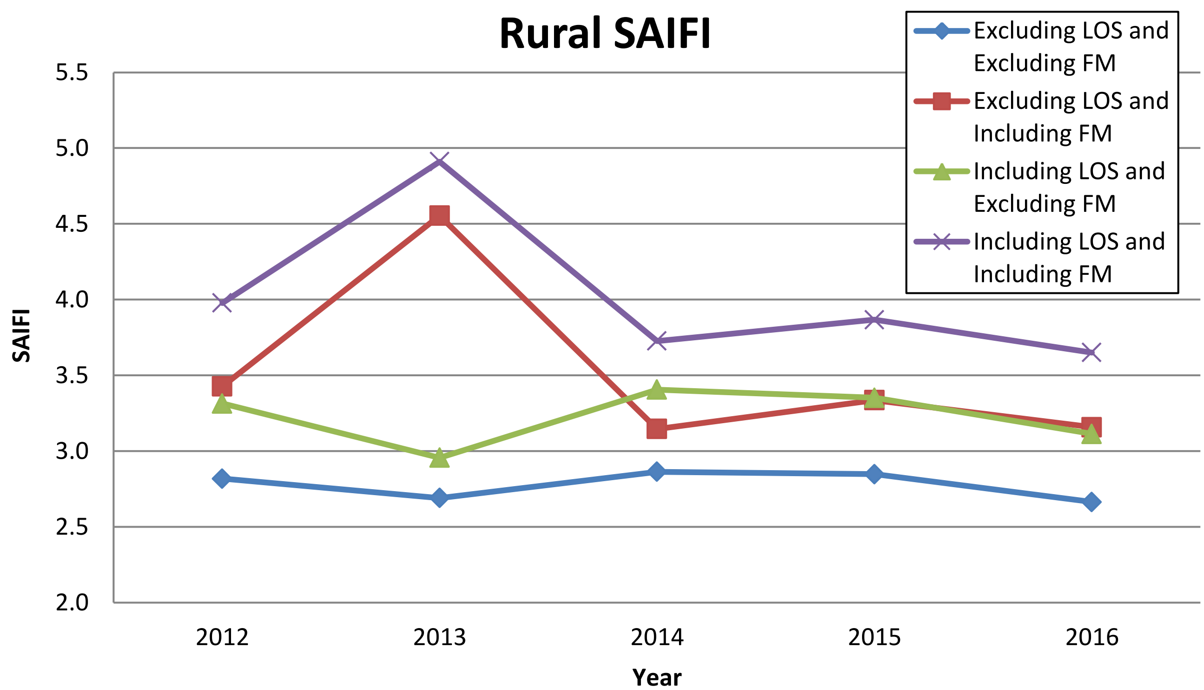


Figure 5 – Chart of Historical Rural SAIFI

Table 6 - Historical Rural CAIDI Summary

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

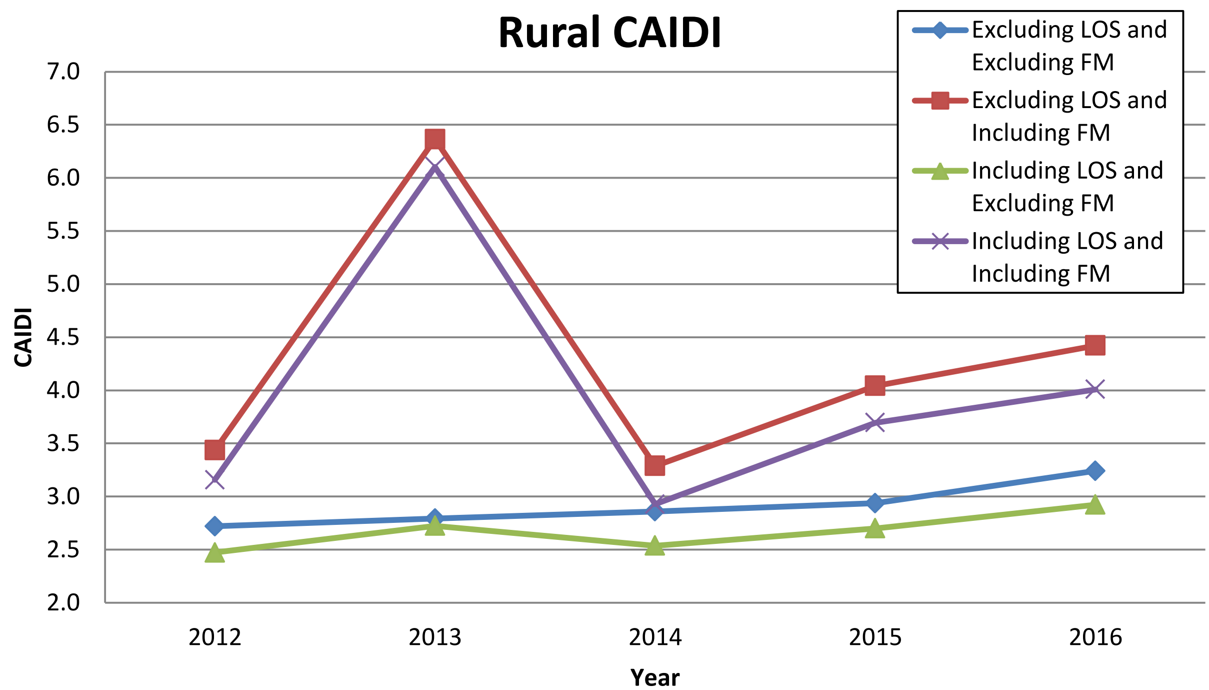


Figure 6 – Chart of Historical Rural CAIDI

Energy Storage Canada Interrogatory # 3

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?

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

Reference:

Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications (the Filing Requirements), Chapter 5: Consolidated Distribution System Plan Filing Requirements, section 5.0.4.3 at page 4 and section 5.4.1 at page 15.
Exhibit B1, Tab 1, Schedule 1
Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1
Exhibit B1, Tab 1, Schedule 1, Section 3
Exhibit C1, Tab 1, Schedule 3, page 8.

Interrogatory:

Preamble:
The Filing Requirements require that Hydro One's distribution system plan (DSP) include the consideration(s) Hydro One has given to the investments necessary to facilitate the integration of distributed generation and customers with energy storage capability.

Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1 shows that 9%-16% of Hydro One customers prioritize upgrading the system to connect new customers, including those using energy storage.

Hydro One describes energy storage at Exhibit C1, Tab 1, Schedule 3, page 8, as one of "the most impactful disruptive technologies affecting utilities over the coming decade due to rapidly declining cost and mass production" and that it "has potential benefits to utilities in terms of peak load shifting (thereby having a positive effect on deferring asset replacement), frequency regulation (improving power quality for customers), reserve capacity (providing better reliability), and improved voltage support".

a) Please describe how Hydro One has considered and implemented energy storage planning and investment into its DSP. Please provide a chart showing:

i. all instances where Hydro One has considered energy storage (as a solution, alternative to a wires investment, or otherwise);
ii. whether or not the energy storage project was implemented;
iii. if the energy storage project was not implemented, the reasons why it was not implemented;
iv. if the energy storage project was implemented, the quantified system benefits, the deferred distribution investment, and the customer rate impact of the project; and
v. all instances where Hydro One has considered and/or incorporated energy storage in its capital planning decision-making processes.

Response:

i. Hydro One is in the feasibility stage of evaluating energy storage for three different applications:
- Reliability improvement
- Power quality
- Deferring other capital investments required to supply load growth

ii.-iv. As these projects are in the feasibility stage, the decision to implement has not been made. The expected system benefits and rate impacts are currently being investigated.

ii. Hydro One has not begun incorporating energy storage in its capital planning process at this time. Should the applications listed above provide meaningful grid benefits in a cost effective manner, Hydro One will move to incorporate energy storage more fully into the planning process.

In addition to the discussion above, please refer to Exhibit I-23-OEB Staff-87 for further energy storage projects considered under the Advanced Distribution System project (see Exhibit B1, Tab 1, Schedule 1, section 3.8, Investment Summary Document SS-07).

Ontario Sustainable Energy Association Interrogatory # 17

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 1.3 Page: 228 - IPSOS Document, Community Meetings

Preamble: "Over time, Hydro One's provincial reliability performance has remained consistent."

Interrogatory:

a) Based on the maps, Hydro Ones regional reliability is consistently worse that the rest of the province's distribution systems. Please provide the standard residential distribution charges for each distribution utility in Ontario including Hydro One.

Response:

a) The requested information is available on the Ontario Energy Board's website at: https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates#tab-distribution-rates-databases--2

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

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

School Energy Coalition Interrogatory # 37

Issue:

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

Reference:

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

Interrogatory:

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

Response:

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

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

Table 9 – Outcome Measures from EB-2013-0416

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

***Table 9 is corrected for a typographical error in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4, s.1.4.2 Outcome Measures: EB-2013-0416, Table 9, Actual 2016 values.**
****No longer measured, replaced by Billing Accuracy measure, refer to Exhibit I-18-SEC-29, Electricity Distributor Scorecard.**

Witness: JESUS Bruno

Table 10 - Historical SAIDI Summary

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

Table 11 - Historical SAIFI Summary

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

Table 12 - Historical CAIDI Summary

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

Table 13 - SAIDI by Outage Cause

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

Table 14 - SAIFI by Outage Cause

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

Table 15 - CAIDI by Outage Cause

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

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:

Audited 2017 actuals are unavailable at this time. An update will be filed once they become available.

School Energy Coalition Interrogatory # 39

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:

B1-1-1, DSP

Interrogatory:

Please provide a list of measurable outcomes that Hydro One forecasts its customers will receive as a result of the incremental investments it has proposed.

Response:

Please refer to Exhibit Q, Tab 1, Schedule 1, Attachment 1, Distribution Business Plan 2018-2023, p.20, Distribution System Plan: Productivity Outcome Measures.

School Energy Coalition Interrogatory # 40

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 1.1 Page: 20

Interrogatory:

Please provide copies of materials provided to participants for each of the three investment planning training segments.

Response:

See Attachments.

Attachment 1: Introduction to Hydro One's Investment Planning Process (Winter 2016)
Attachment 2: Introduction to Asset Investment Planning Risk Assessment (Winter 2016)
Attachment 3: AIP Tool Training Manual (January 20, 2016)
Attachment 4: Dx Investment Planning Cycle 2017-2022 Management Training (May 2016)
Attachment 5: Investment Planning Schedule
Attachment 6: Consequence Taxonomy Table
Attachment 7: Baseline Risk Statement Guidance
Attachment 8: High Level Estimating and Pre-engineering Process Graphic
Attachment 9: AIP Critical Inputs - Checklist
Attachment 10: AP Manager Check List Field Descriptions
Attachment 11: AIP Concepts and Definitions
Attachment 12: Risk Assessment Framework and AIP Risk Matrix
Attachment 13: Module 3B: Sunflower Cove Case Studies
Attachment 14: Case Study
Attachment 15:AIP Tool Training Exercises Create New Project - Dx
Attachment 16: AIP Tool Training Exercises Update Program Investment

Witness: JESUS Bruno

Introduction to Hydro One's Investment Planning Process

Winter 2016

Agenda

- Overview
- Module 1: Business Planning vs Investment Planning
- Module 2: The World Affecting your Investment
- Module 3: Your Responsibility as an Investment Owner
- Module 4: How Investments are Selected
- Module 5: Investment Planning Approvals
- Module 6: Related Processes

Objectives

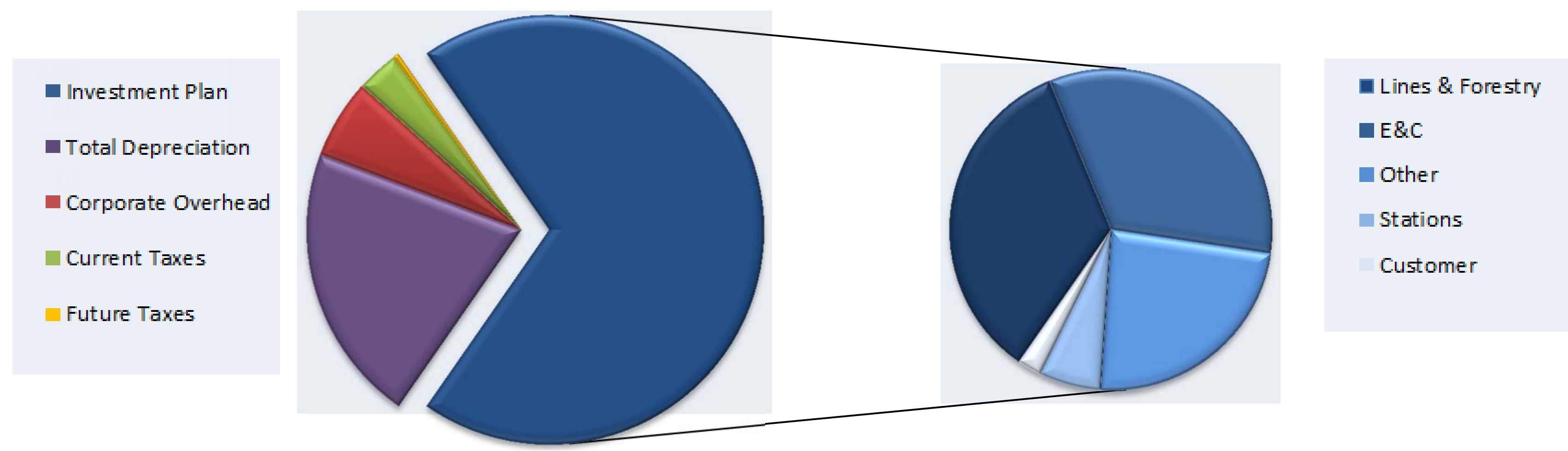
- Learn about the Investment Planning Process (IPP) and its interdependencies to the corporate Business Planning Process
- Understand the context within which the Investment Plan is being developed and the process goals/metrics
- Recognize the steps in the high-level IPP
- Be able to identify focus areas and expectations of the IPP, including productivity and related metrics
- Understand the relationship between investment planning and parallel processes such as work release, budgeting, resource planning, etc.
- Understand the basics of the optimization process

Module 1

BUSINESS PLAN VS. INVESTMENT PLAN

Business Plan vs Investment Plan

Corporate Business Plan	Investment Plan
Overall 5 year Financial Outlook for *Hydro One Limited.* that spans: • Subsidiaries (Networks, Remotes, Telecom, Acquisitions) • Investments • Staffing & Overheads • Revenue Forecasts • Other (Tax, Depreciation, Working Capital, etc.)	**The *Hydro One Networks* investments planned for the selected time period (all the work that we do):** • Sustainment • Development • Operations • Customer • Other **The Plan Considers:** • Asset Needs (Short-term and Long-Term Risks) • Corporate Objectives • Financial, Regulatory, and Resource Constraints
$3.6B CapEx and OM&A	**$2.5B CapEx and OM&A**



Your Role in the Investment Planning Process

Investment Formulization

- Need Identification
- Strategy Development
- Alternative Evaluation
- Risk Assessment
- Workflow Submission

Module 2

THE WORLD AFFECTING YOUR INVESTMENT

2016-2020 Investment Plan Update

- 2016 was approved by the Board for budgetary purposes on January 14th
- 2016-2018 to be submitted to the Board in early May for approval prior to Tx Rate Filing at the end of the month

Lessons Learned

- Dedicated Quality Assurance period to resolve issues/discrepancies
- Enhance Coordination/Collaboration between planning groups
- Remodel Training Material and Tool Packages
- Consistent Risk Approach
- Direction regarding concept and effects of Investment Shifting and Alternative Levels
- Lessons Learned Report

Corporate Strategy:
Becoming Canada's Leading Utility

hydro one

	Uniting Behind the Goal 2014	Enabling our People 2015-16	Unlocking Performance 2017-18
Safety	Creating an injury free workplace and maintaining public safety	Safety	World Class safety performance
Customer	Satisfying our customers	Customer	Satisfying experience & trusted partner
People	Championing people and culture	People	High performance culture
Business Excellence	Reliable, affordable Tx & Dx systems Improve productivity and cost effectiveness Increasing value for our shareholder	Business Excellence	Reliable Power Cost Effective Pride in Shareholder Value Creation

Strategic Plan 2014-2019

Corporate Scorecard 2014-2019

Canada's Leading Utility

Our Employees, Customers, and the people of Ontario

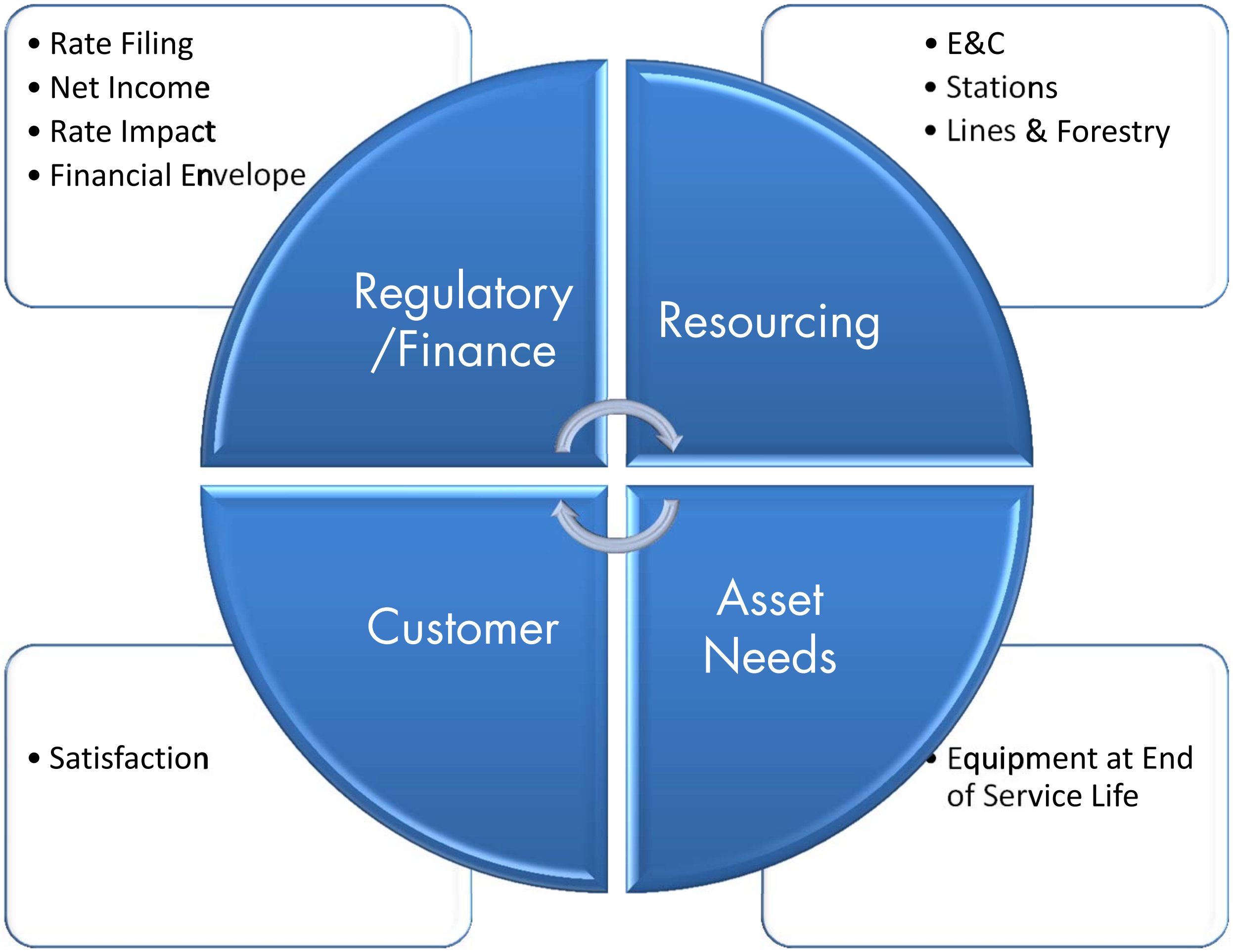
BELIEVE

We are a company of great people providing

safe, reliable, excellent and affordable service

Hydro One's Business Values

Constraints



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

Financial Framework

Financial Envelope

Asset Need	Inflation	Productivity	Rate Base Growth 4.2%

Investment Plan Guided by Financial Envelope of Previous Plan

Regulatory Framework

- Plans should be consistent with approved rate decisions/applications in-flight
- Transmission
  - Consistent with 2016-2020 Plan and align to rate filing for years 2017-2018
- Distribution
  - To follow OEB Decision for 2017 and assume IRM rate regime (inflation less productivity) for 2018-2022

Benchmarking

- OEB has mandated productivity studies for both Transmission and Distribution
- Outcome from results of the Studies to be expected in the summer
  - May cause potential changes to the plan between internal approval and Board Approval submission

Touch point

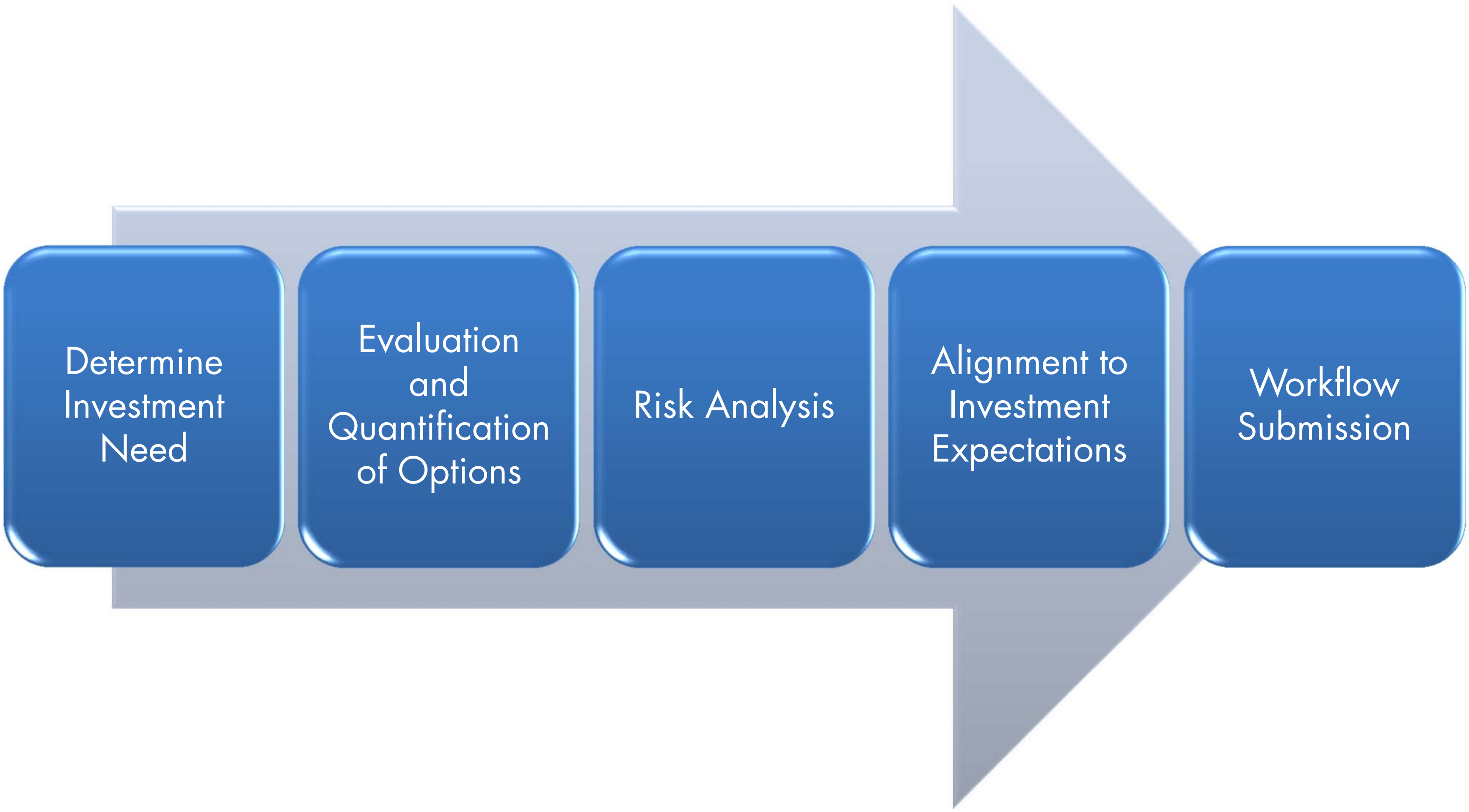
- Name 3 Key Business Values for Hydro One

- What expected decisions may result in a change to the Investment Plan?

Module 3

YOUR RESPONSIBILITY AS INVESTMENT OWNER

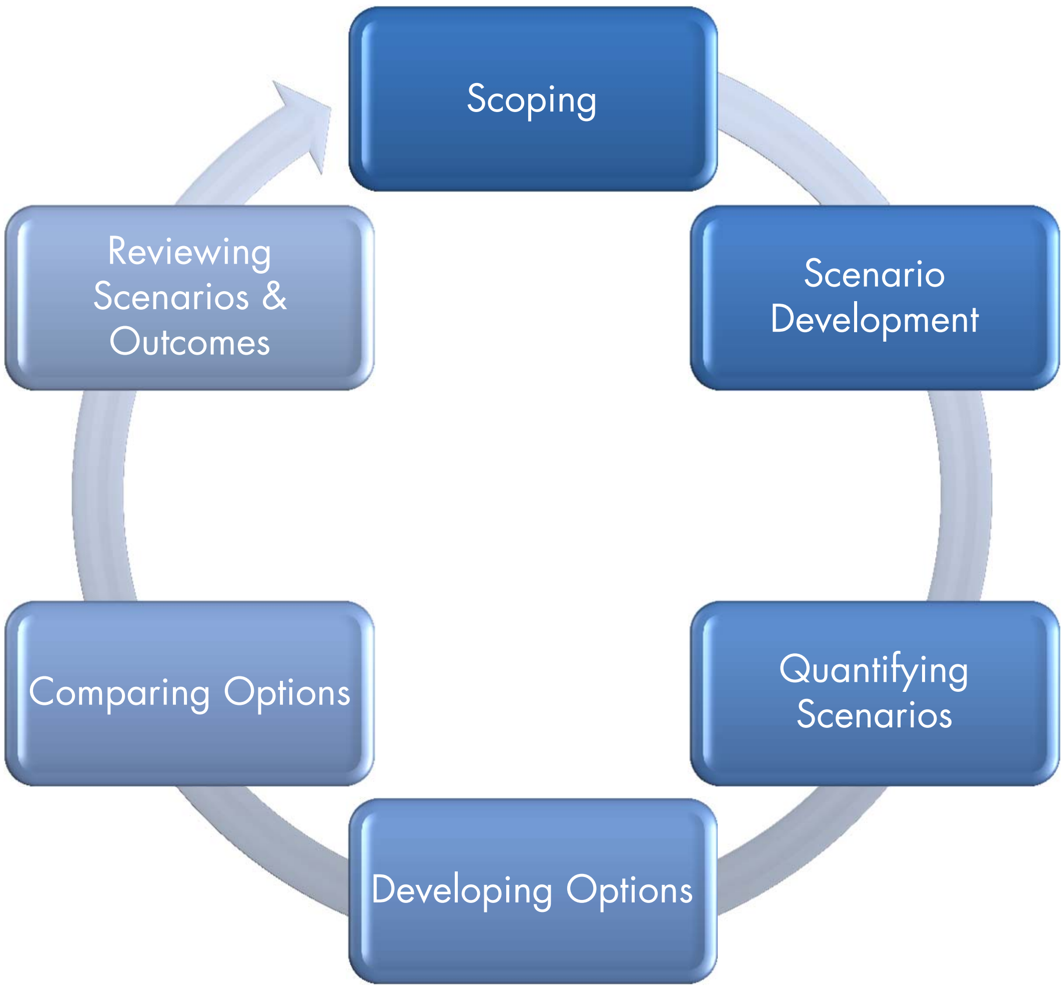
Role of Investment Owner



Investment Strategy

- Audit Approach to Investment Planning
- All investments must be justified through data analysis with supporting documentation
- Focus on Productivity with emphasis on unit accomplishments

Investment Assessment Process



Program

Definition **(as per SP1078)**

The total of all transactions relating to a specific body of work where the type of work **recurs year over year**. The extent of the work executed in any particular year, may change from year to year depending on its ranking in the prioritized programs and the overall availability of funds. Alternative approaches do not exist to achieve the objective.

NOTE:

In-Service Additions calculated on a ***ratio*** basis

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

Project

Definition (as per SP1078)

The total of all transactions relating to a specific body of work that is a **one-time event** that occurs during a specific time period. This period may cover more than one fiscal year. **Alternative** approaches can be taken to achieve the objective and there is a greater level of risk.

NOTE:

In-Service Additions determined by ***In-Service Date of total Net Costs***

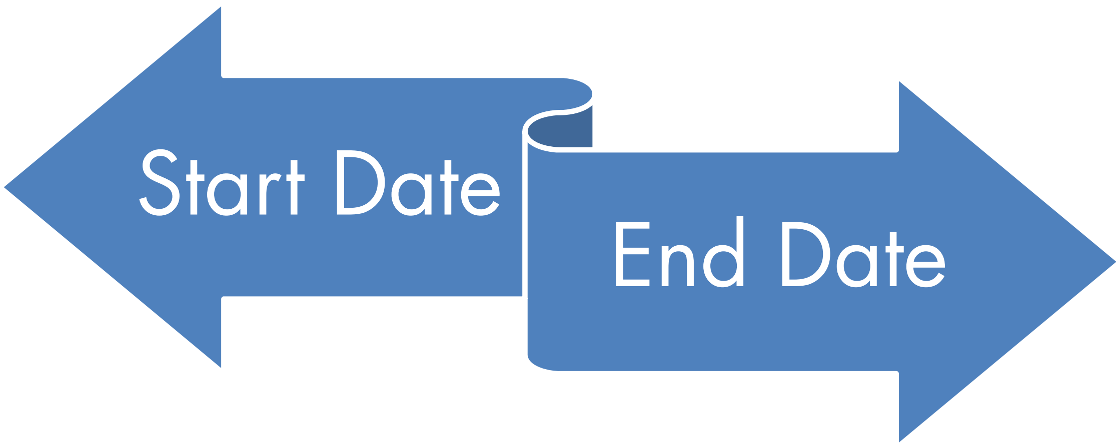
All Integrated Investments are now **PROJECTS**

Updates to **Released Projects** are based on Multi-year Forecast from Service Provider and therefore are not the responsibility of the Investment Planner

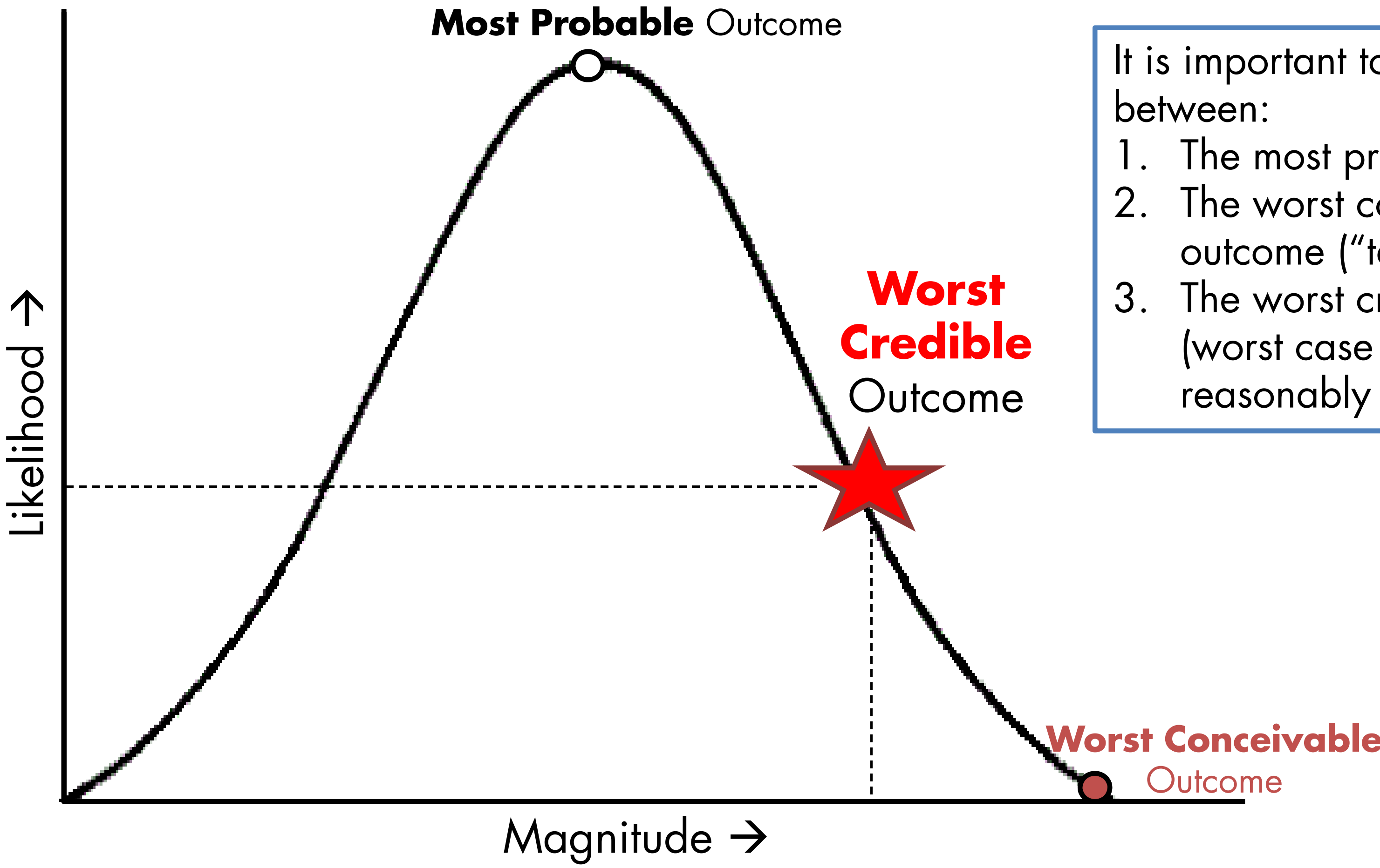
Parameters | Investment Input | Investment Review | Optimization | Enterprise Engagement | Approval

Project Alternatives

- Project Alternatives are determined by the ability to **Shift** an investment
- Criteria based on the Earliest Start Date and the Latest Start Date
- Multiple Alternatives may be provided where appropriate
- Allows a level of confidence for those investments containing:
  - Signed Customer Agreement
  - Currently in the estimating process
  - Long-lead material



Hypothetical Risk Distribution Curve



It is important to differentiate between:

1. The most probable outcome
2. The worst conceivable outcome ("tail risk")
3. The worst credible case (worst case that may reasonably occur)

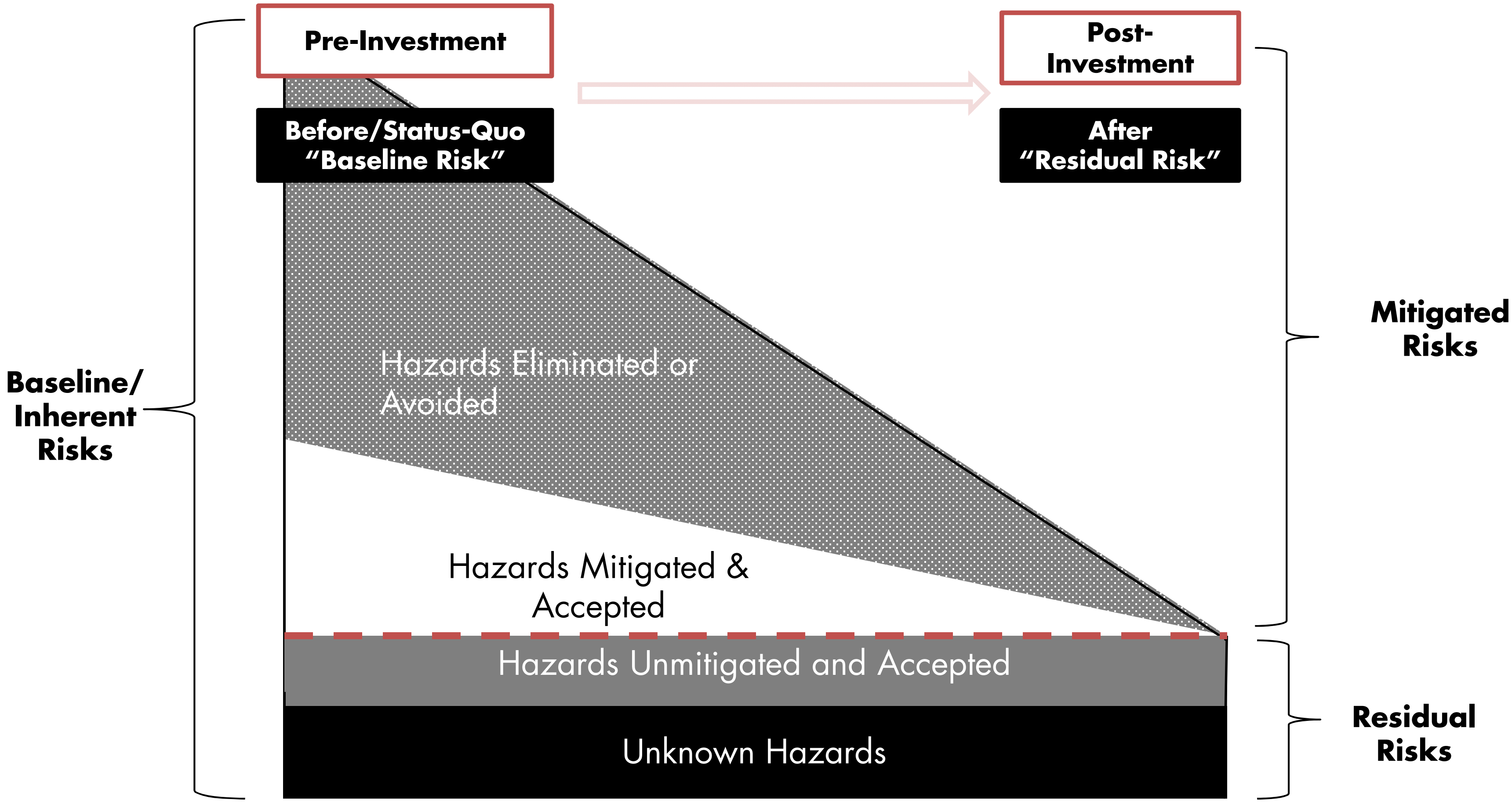
Investment Planning Risks Assessments

Hazards/Threats
- Fire
- Explosion
- Severe Weather
- Hazardous materials spill or release
- Mechanical breakdown
- Equipment condition
- Cyber Attack
- Physical Attack
- Theft and vandalism
- Obsolescence
- Inefficient processes
- Non-Compliance

Assets at Risk
- People
- Power system facilities
- Customer Relationship
- Systems/Equipment
- Information Technology
- Operational performance
- Business Operations
- Financial profile
- Regulatory and legal obligations
- Environment
- Company Reputation

Consequences
- Workforce/Public Injuries
- Performance and reliability
- Erosion of customer goodwill
- Environmental release/contamination
- Financial loss
- Loss of Shareholder confidence
- Regulatory credibility
- Regulatory compliance
- Fines, penalties and sanctions

Risk Informed Investment Decisions



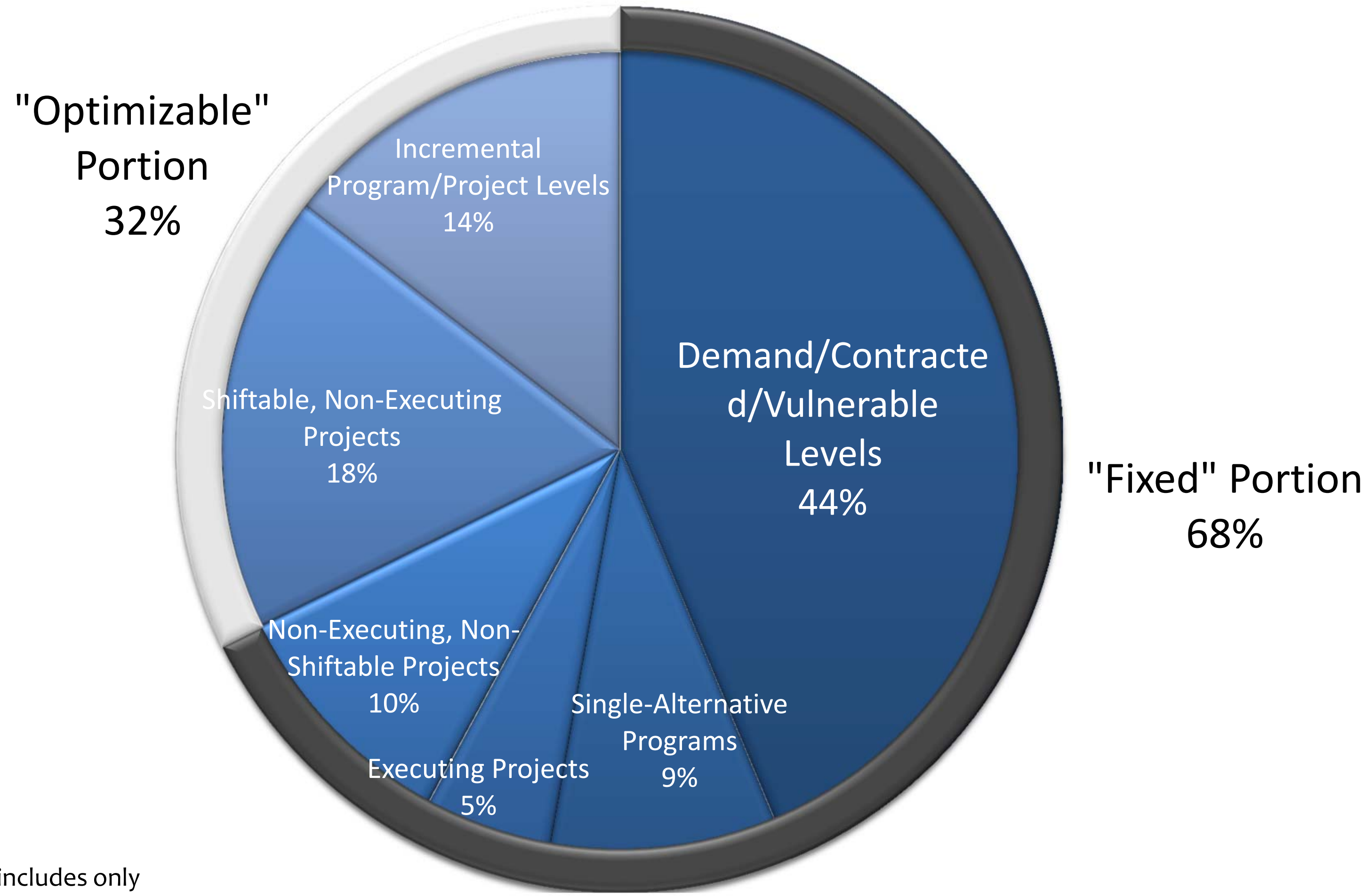
Expectations & Metrics

- Key Performance Indicators (KPIs) will be implemented to measure the end-to-end Investment Planning Process
- Including overall metrics such as:
  - Plan contributes to acceptable rate increase
  - Balanced plan developed & aligned to corporate guidance
  - Increase the "optimizable" portion in the plan

Note: ⍓ indicates metric

Investment Plan Optimization

5-Year Net Total (2016-2020)



As of May 14, 2015; includes only selectable alternatives

Investment Input Expectations

Category	Components	Metric
Supporting Documentation	Asset Analytics Investment Development & Justification Scope Financial & Asset evaluations Risk/Value Assessment Potential Need Notifications	
Ability to Optimize	Shifting of Non-Executing Projects Viable Alternatives for Non-Demand/Non-Contract Programs No Near-Term Placeholders	
Planning Timelines	Logical and aligned to Estimating guidelines No Year End In-Service Dates (ISD)	
Enterprise Engagement	Discussion of Key Investment Details such as: • All cost assumptions are to be agreed by Work Program Management • UPC • Sourcing Model • Planning Timelines	

Tx Investments with Dx Contributions

- Both ARs to have same Service Provider
- Funding Party (Dx) has a Gross Plan equal to the receiving party's (Tx) Capital Contribution from Dx
  - Note: Tx may have capital contributions in addition to Dx
- The timing of the matching Dx Gross $ and Tx Cap Contribution must be equal on an annual basis and offset one another

Investment Input Quality & Analysis

- IM Team to complete Pre & Post Investment Submission Review with feedback provided on data quality and completeness

- Reviewer Feedback will be provided to the investment owner via a meaningful Manager Check-list
  - Checklist will serve as a basis for many KPIs

- Essential for Investment Quality, as minimal changes will be allowed post-optimization

Metric

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

Investment Approval Workflow

	Optional	Mandatory	>$15M/10M Optional	>$15M/10M Mandatory
Investment Owner (IO) →	Interim Reviewer #1 →	Driver Owner (Manager/ Director) →	Interim Reviewer #2 →	Portfolio Owner (Director)
e.g. Don Mastrangelo	Ken McNeil	Bruno Jesus		CK Ng

- All Investments must be approved through Workflow and status will be tracked and reported

Metric

Investment Approval Submission

- Investment Planning Approval Documents (iPADs) are to be submitted post Workflow Approval for each Driver
- Asset Portfolio Documents (APDs) are to be submitted for asset types where appropriate
- Developed by the Director and based on investment owners proposed scenario for investments contained in associated Driver
- Used during IRRC Planning Review to provide insight into Strategies and Risk associated with Investments within the Plan

Touch Point

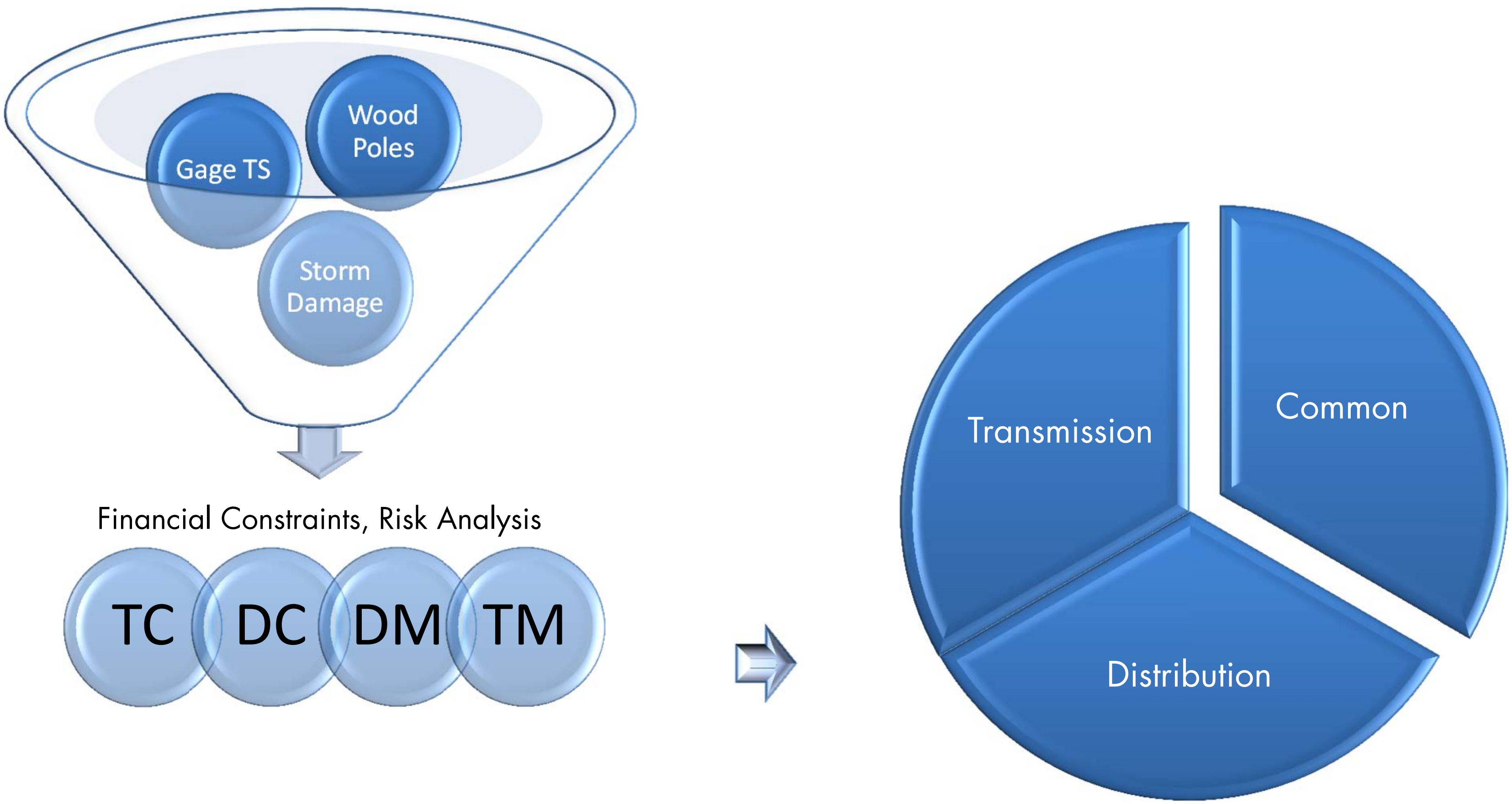
- What are the key responsibilities of an Investment Owner?

- Name three expectations for an investment that will be tracked as a metric

Module 4

HOW INVESTMENTS ARE SELECTED

Optimization



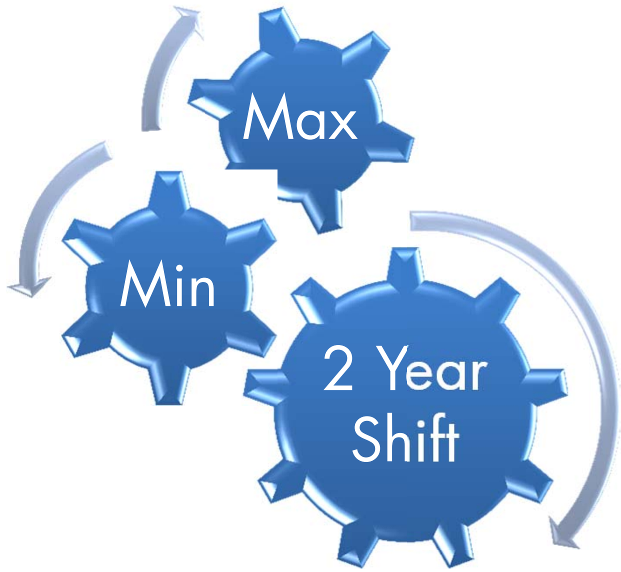
Best Selection and timing of investments

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

Optimization Analysis

- Various scenarios are run by the IM Team to understand the data and achieve an optimal plan

- Risk Calibration sessions will be completed pre-optimization



Enterprise Engagement

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

Enterprise Engagement Expectations

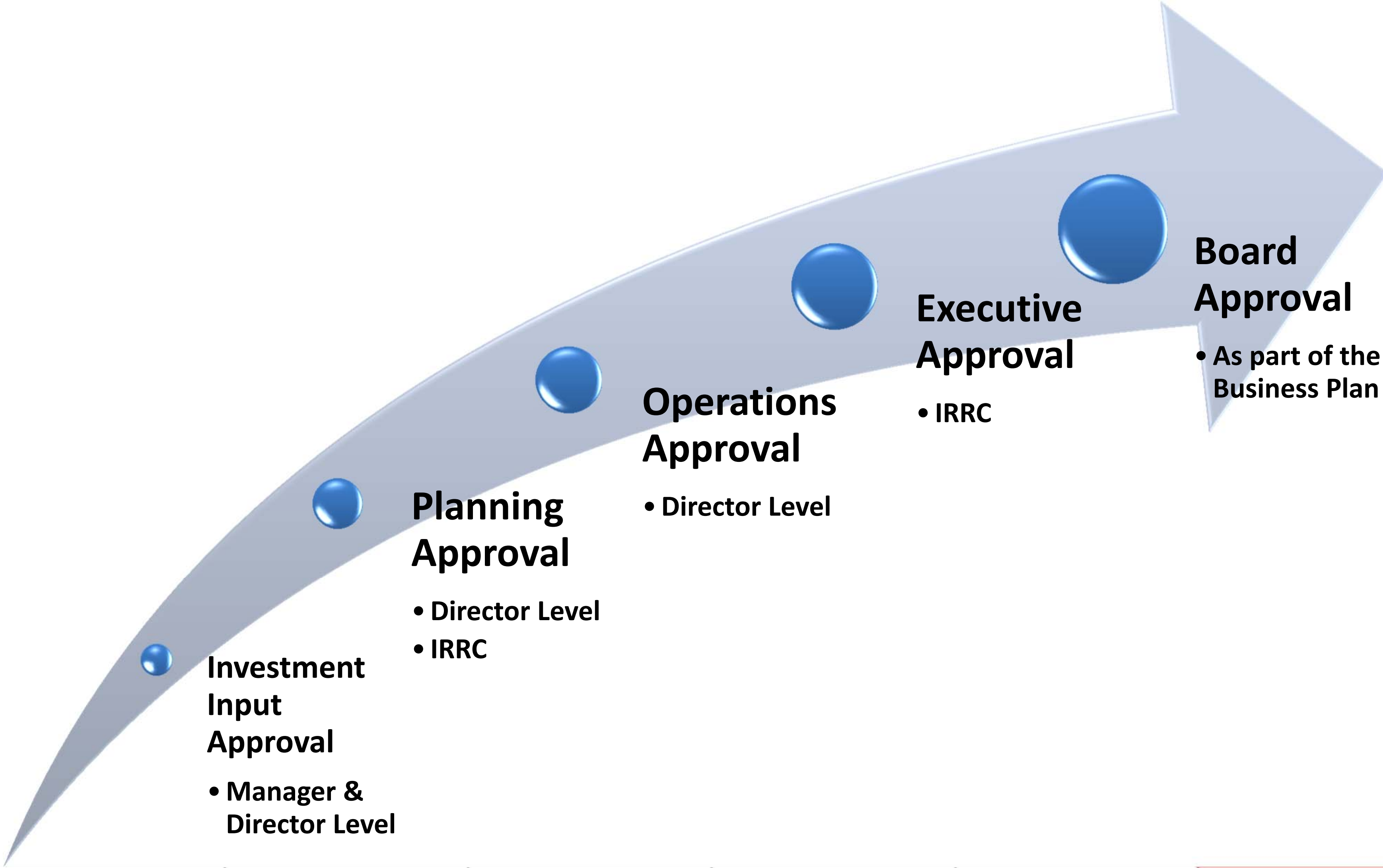
Expectation	Metric
Unit Prices from Operations are available to Planners and have been agreed to by both parties	
Operations (thru Finance) will provide a multi-year forecast of released projects Monthly	
Collaborative Effort between Planning and Operations for Funding Redirection	
Collaborative process to ensure investments have accurate costs and realistic timelines considering resource constraints	
All LOBs will participate in the finalization of the Investment Plan	

Metric

Module 5

INVESTMENT PLANNING APPROVALS

Investment Plan Approval Stages



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

Module 6

RELATED PROCESSES

Related Processes

- ACER/Work Release
- Budgeting
- Resource Planning
  - Estimating
  - Stations including CMS
  - Construction Services
  - Lines & Forestry
- Outage Planning

Schedule

Date	Segment	Duration
Training		
Jan 11 - Feb 10	Planner & Manager Training	4 weeks
Input		
Jan 30	Operations provides Unit Price Catalogue; Planning accepts Unit Price Catalogue	1 day
Feb 1 - Mar 28	Planner Input	8 weeks
Feb 24	Investment Planning Drop-in Session	½ Day
Mar 9 - 16	QA Review	1 week
Mar 22	Investment Planning Drop-in Session	½ Day
Mar 28 – May 4	Manager/Director Review of Input	4 weeks
Apr 27 – May 3	Investment/Risk Calibration	1 weeks
Optimization and Review		
May 5 – May 18	QA and Optimization	2 weeks
May 19 – 25	Director Review of Optimization Results	2 weeks
May 26 – June 1	Executive Review	1 week
Enterprise Engagement		
June 2 – 20	Executing LOB Review (Lines, Forestry, Stations, E&C)	3 weeks
Investment Plan Approval		
June 30	IRRC IPP Review and Approval	1 day
June 30	Investment Plan Proposal Complete	

Investment Planning Team

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Michael Fraites

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Alex Jackson

X 5602

Investment Planning Inbox - Investment Planning@hydroone.com

- Training Site
- AIP Tool
- Draft Accomplishment File
- AR Docs
- Risk Consequence Table
- Project Hub – Gantt Chart Directory

Questions??

Introduction to Asset Investment Planning Risk Assessment

Winter 2016

Agenda

- Introduction
- Module 1: Risk Overview
- Module 2: Introduction to Asset Risk Management
- Module 3: Case Studies/Exercise – Hydro One/Sunflower Cove
- Appendices
  – Module 4: System Events: Transmission
  – Module 5: System Events: Distribution
  – Module 6: Tool Kit Reference Points

Course Objectives

Course Description

- This course will introduce participants to the way in which Hydro One makes an assessment of and controls risk within the Investment Planning Process (IPP).
- The goal of the course is to engage participants in risk management principles, and provide a tool kit to adequately assess and control investment planning risks.

Learning Objectives

- Learn about Hydro One's approach to risk and the importance of it within the context of the IPP
- Understand Hydro One's business values and risk tolerances
- Understand the key principles and considerations of risk assessments within the context of the IPP
- Be able to apply risk tolerances to specific investments (via the tool kit)

Overview: Why are we doing this?

- Risk management is an important foundation for asset management.
  - Understand the cause, effect and likelihood of adverse events and manage associated risks to an acceptable level

- Improve consistency within and across groups through a defensible and consistent approach
  - Articulating assumed scenarios
  - Providing quantitative and empirical evidence to support scenarios

- Provide increased visibility and transparency to risk analysis
  - Facilitate "challenge sessions" to normalize risk assessments
  - "How'd they get that?"

- Institutional knowledge / knowledge transfer
  - "What were they thinking?"

- AIP Value Realization
  - Strengthening the link to expected impact on Key Performance Indicators

Module 1:
Risk Overview

Key Principles

Enterprise Risk Management Policy (HODS0736):

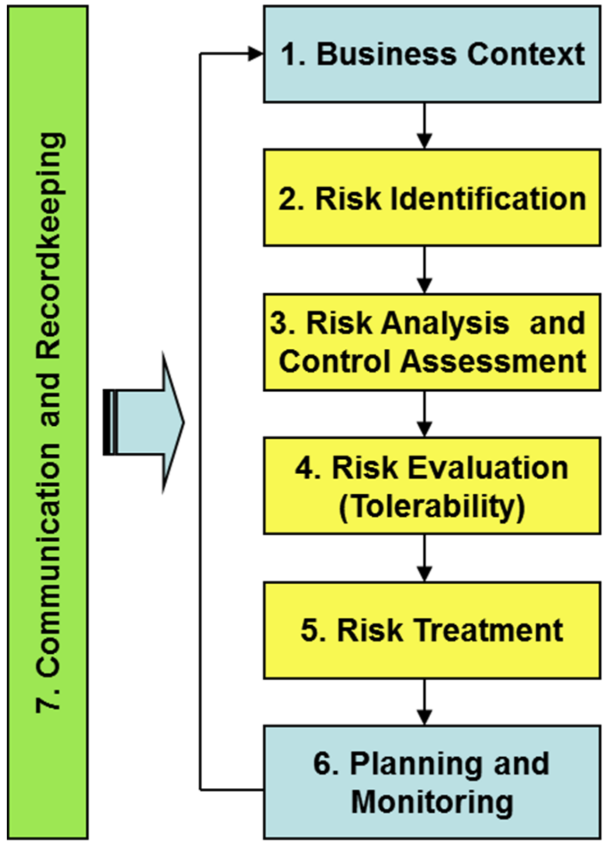
- Risk management is everyone's accountability…each is expected to understand the risks that fall within the limits of their accountabilities and is expected to manage these risks within approved risk tolerances.
- Hydro One will manage its significant risks through a portfolio approach that optimizes the trade-offs between risk and return across all business functions.
- Enterprise Risk Management will be integrated with major business processes such as strategic planning, business planning, operational management, and investment decisions to ensure consistent consideration of risks in all decision-making.

Risk: The effect of uncertainty on Hydro One's objectives. Risk is described in terms of its likelihood of occurrence and potential impact or magnitude.

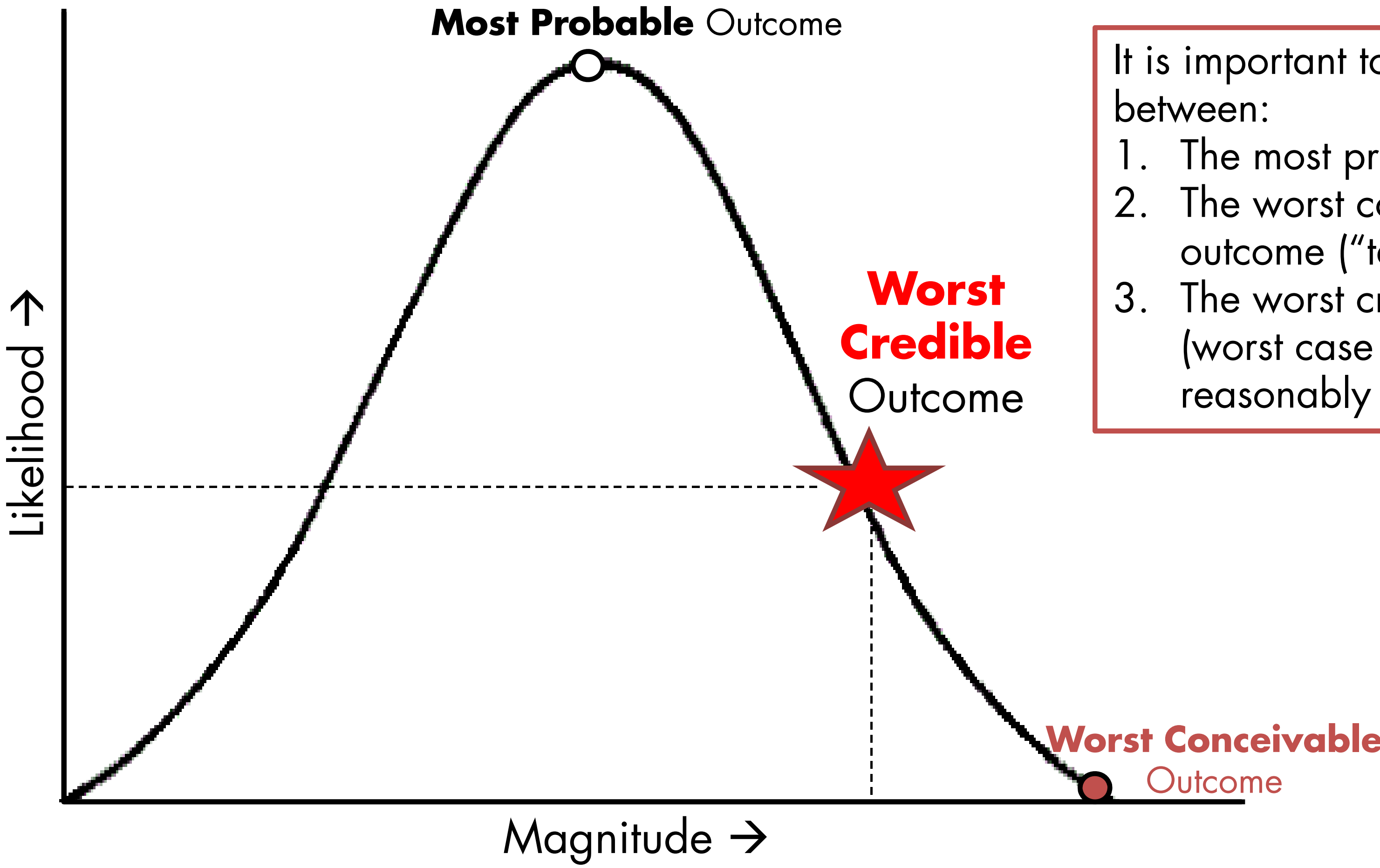
Risk management is not a stand-along activity, but is an inherent component of planning, executing and monitoring the corporation's activities

Risk Assessment Framework

- Understand the risk, and how it connects to our objectives
- Define and assess the **Worst Credible Risk**
- Measure it relative to some **consistent standard for acceptability** [Consequence Table]
- Examine what we **have in place or planned to mitigate it**
- Make a conscious choice on how to handle it:
  - Take more?
  - Accept as-is?
  - Take less:
    - Exit?
    - Transfer?
    - Reduce likelihood?
    - Reduce impact?
- **Have a record of the above**



Hypothetical Risk Distribution Curve



It is important to differentiate between:

1. The most probable outcome
2. The worst conceivable outcome ("tail risk")
3. The worst credible case (worst case that may reasonably occur)

Structured Risk Assessment

Key Steps	Considerations	
1. Risk (Hazard/Threat) Identification	Consider major risk categories as: • Operational Risks, including Asset Risks and Human Capital Risks • Reputational/Stakeholder Risks • Financial Risks	• Identify threats and hazards of concern based on experience, forecasting, expertise and other available resources • What can happen? How can it happen?
2. Risk Analysis and Controls Assessment	Describe the threats and hazards of concern, showing how they may impact objectives/Business Values	Defining credible scenarios and quantifying the inherent/baseline risk 1. Assess the **worst credible** magnitude of the risk 2. Assess the strength and effectiveness of current or committed controls 3. Assess the likelihood of the worst credible impact in light of current or committed controls
3. Risk Evaluation	Determine tolerability of the risk ("Are we ok with this?")	
4. Risk Treatment	For risks deemed "tolerable", determine the appropriate action to take: • <u>Retain</u>: Accepted as-is without change to mitigation • <u>Retain, but Change Mitigation</u>: Accept but a change in mitigation reduces the cost of control or produces other benefits. • <u>Increase</u>: potential return is viewed as desirable, or the controls in place are excessive or not cost-effective.	For risks deemed "intolerable", determine the appropriate action to take: • <u>Avoid</u>: Risk exposure will be avoided entirely • <u>Reduce the Likelihood</u>: Risk exposure will be reduced through new or enhanced preventive controls. • <u>Reduce the Consequences</u>: The impact of any risk that materializes will be reduced. • <u>Share</u>: Risk exposure will be shared with others (e.g. insurance).

Module 2:
Introduction to Asset Risk Management

The Theory:
Risk-Based Decision Making

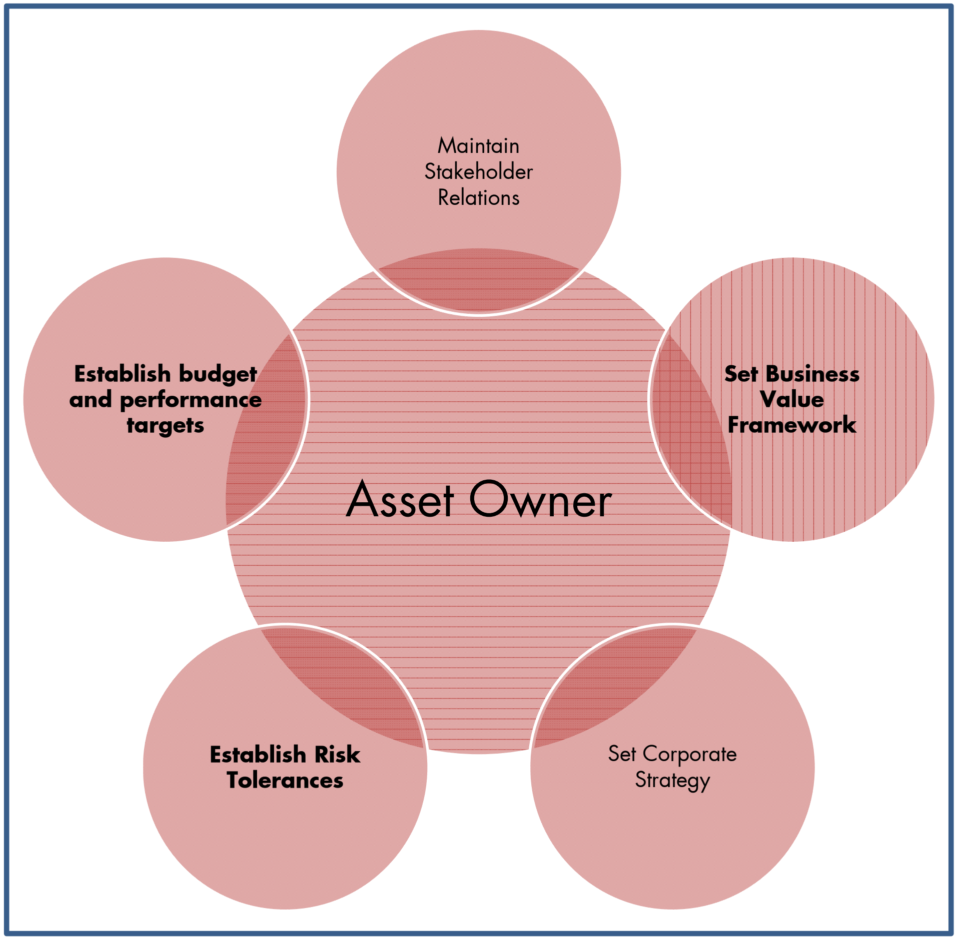
- Business risks are any potential future events/occurrences that could result in the Company failing to meet one or more of its short and/or long-term business objectives.

- Hydro One's Senior Management and the Board of Directors has defined a common set of risk tolerances used in assessing risk magnitude, that reflect Hydro One's risk appetite.

- Inherent business risks must be assessed, quantified and prioritized on the basis of Hydro One's Business Values before deciding to deal with a risk.

- Hydro One manages these risks by considering alternative investments through a combination of reducing the likelihood and/or the consequence of the risk occurrence to a tolerable or acceptable level.

Asset Management Model: Asset Owner



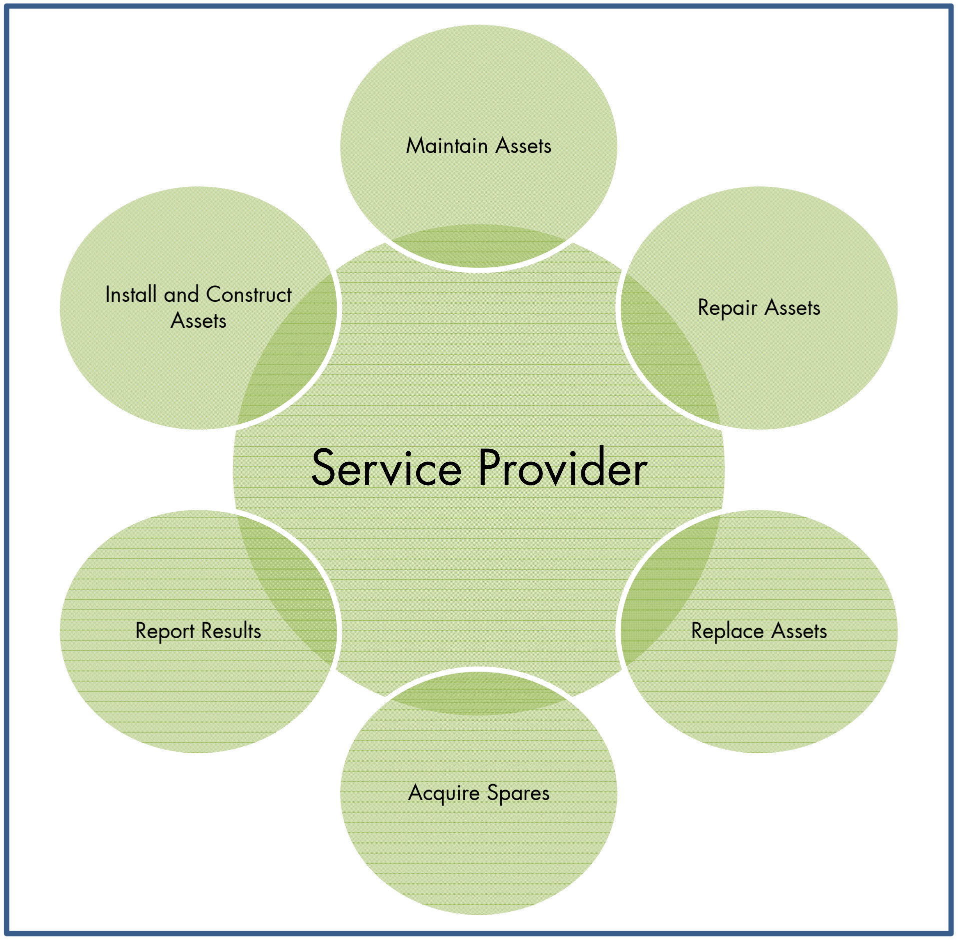
Asset Management Model: Asset Manager

Determines WHAT has to be done WHEN and WHERE to realize objectives set by Asset Owner

Tx Asset Management, Dx Asset Management, System Development, etc.

Asset Owner → Asset Manager → Service Provider

Asset Management Model: Service Providers



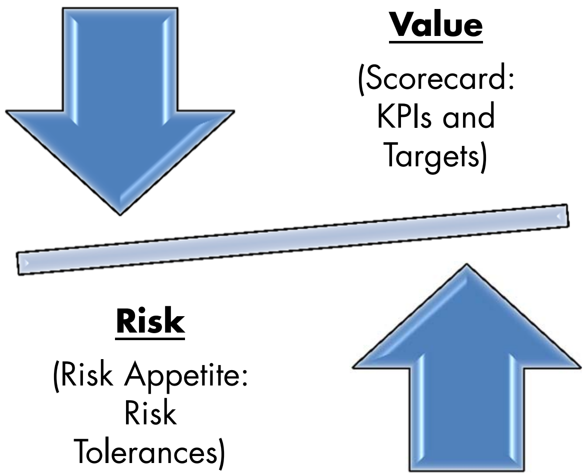
Determines HOW the work is done keeping costs to a minimum for the levels of work and quality identified by the Asset Manager

Lines, Forestry, Construction, Stations, etc.

Asset Owner → Asset Manager → Service Provider

Asset Investment Planning and Optimization

- Framework to consistently manage risk and facilitate trade-offs between investment alternatives
- Simultaneous assessment of the impact i.e. costs, benefits and risks of investment alternatives against defined Business Value and Key Performance Indicators (KPIs)
- Facilitate scenario analysis of different combinations of alternatives, including those that are considered "must do", "should do" and "desired“
- The Risk Consequence Table helps planners select a ‘consequence’ for each Corporate Business Value (as applicable) and identify risks with the greatest potential to impact corporate objectives
- Allocate resources efficiently and in a cost-effective manner to mitigate the highest priority risks early in the planning process



Business Values and KPIs

Business Value	Objective/Key Success Factor	Planning Measures/ KPI
Safety	Creating an injury-free Workplace and Maintaining Public Safety	• Employee/contractor workforce health and safety • Public safety
Customer	Satisfying our Customers	• OEB service quality index • Large and mid-size customer (industrials, LDCs and Tx /Dx generators) satisfaction • Residential and small business customer satisfaction
Reliability	Building and Maintaining reliable, affordable transmission and distribution system	• Reliable delivery of electricity • System security
Productivity	Achieving productivity improvements and cost-effectiveness	• Productivity • Work Program accomplishment
Employees	Championing People and Culture	• Employee skills: developing, retaining, attracting and competencies
Environment	Protecting and Sustaining the Environment for future generations	• Environmental performance
Shareholder Value	Maintaining a commercial culture that increases value for our shareholder	• Shareholder confidence • Regulatory credibility • Regulatory compliance • Get required approvals from regulators • Public profile and confidence: effective stewardship of assets • Net income • Credit worthiness

Subject to Revision based on Updates to Corporate Strategy

Corporate Objectives and Scorecards

- Demonstrate a clear link between investment outcomes, corporate objectives and the scorecard

Subject to Revision based on Updates to Corporate Strategy

Strategic Objective	Performance Measure	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2015 Target	2019 Target
Injury Free Workplace	Recordable Rate # Recordable per 200,000 hours worked	2.6	3.7	2.3	2.5	1.8	***1.7***	*1.7*	0.9
Satisfying our Customers	Customer Satisfaction – Tx (% Satisfied)	*N/A*	*N/A*	71	*N/A*	76	***79***	*78*	90
	Customer Satisfaction – Dx (% Satisfied)	86	83	85	83	84	***85***	*86*	90
	Connection of New Services (% complete in < 5 days)	91	92	96	97	97	***96***	*95*	95
	Billing Success (%)	*N/A*	*N/A*	*N/A*	*N/A*	97	***99.7***	*99*	n/a
	First Call Resolution (%)	N/A	83	83	78	81	***82***	*83*	87
Continuous Improvement & Cost Effectiveness in the Building and Maintaining of Reliable Dx and Tx Systems	Tx Unit Costs (OM&A/Gross Fixed Assets)	3.5	3.4	3.0	2.7	2.7	***2.9***	*2.8*	2.5
	Dx Unit Costs (OM&A/Gross Fixed Assets)	7.4	7.0	6.4	6.4	6.1	***5.5***	*5.4*	4.7
	Duration (SAIDI) – Tx (minutes per DP)	9.1	8.9	6.8	12.9	11.8	***10.4***	*10.0*	8.8
	Duration (SAIDI) – Dx (hours per customer)	7.1	6.9	7.0	6.9	7.4	***7.6***	*7.1*	6.9
Maintaining a Commercial Culture that Increases Shareholder Value	Net Income ($M)	591	641	*745*	803	*747*	***TBD***	*695*	944
	In-Service Capital – Tx (% of Plan)	87	95	90	94	99	***105***	*95*	100
	In-Service Capital – Dx (% of Plan)	*75*	*73*	*76*	109	*97*	***116***	*95*	100

Risk Assessment Process

Scoping	Scenario Development	Quantifying Scenarios	Developing Options	Comparing Options	Reviewing Scenarios & Outcomes
•Data gathering •Asset/system condition/ performance/ capability •Demand/ performance/ standard requirements	Need identification and problem (Risk Event) definition	Baseline risk analysis (Worst Credible)	•Identification of options to address needs •Screening options •Quantification and evaluation of options	•Residual risk analysis for each alternative •Alternative comparison based on technical, economic, environmental and other factors	Identification of Recommended Alternative

Measuring Risk

Calculating Risk

- Matrices are utilized to assess risk level
- Must consider risk over time
  - Not just at the end of 5 years

Risk	=	Likelihood	✖	Consequence	✖	Control Mitigation Factor

- Likelihood is assessed for each Business Value individually
- Consider costs and risks associated with executing work:
  - Outage staging – costs associated with by-passes; risks associated with configuration changes during construction (load with multi-circuit supply is placed on a single supply to accommodate work program and is left vulnerable to interruption with loss of single supply)

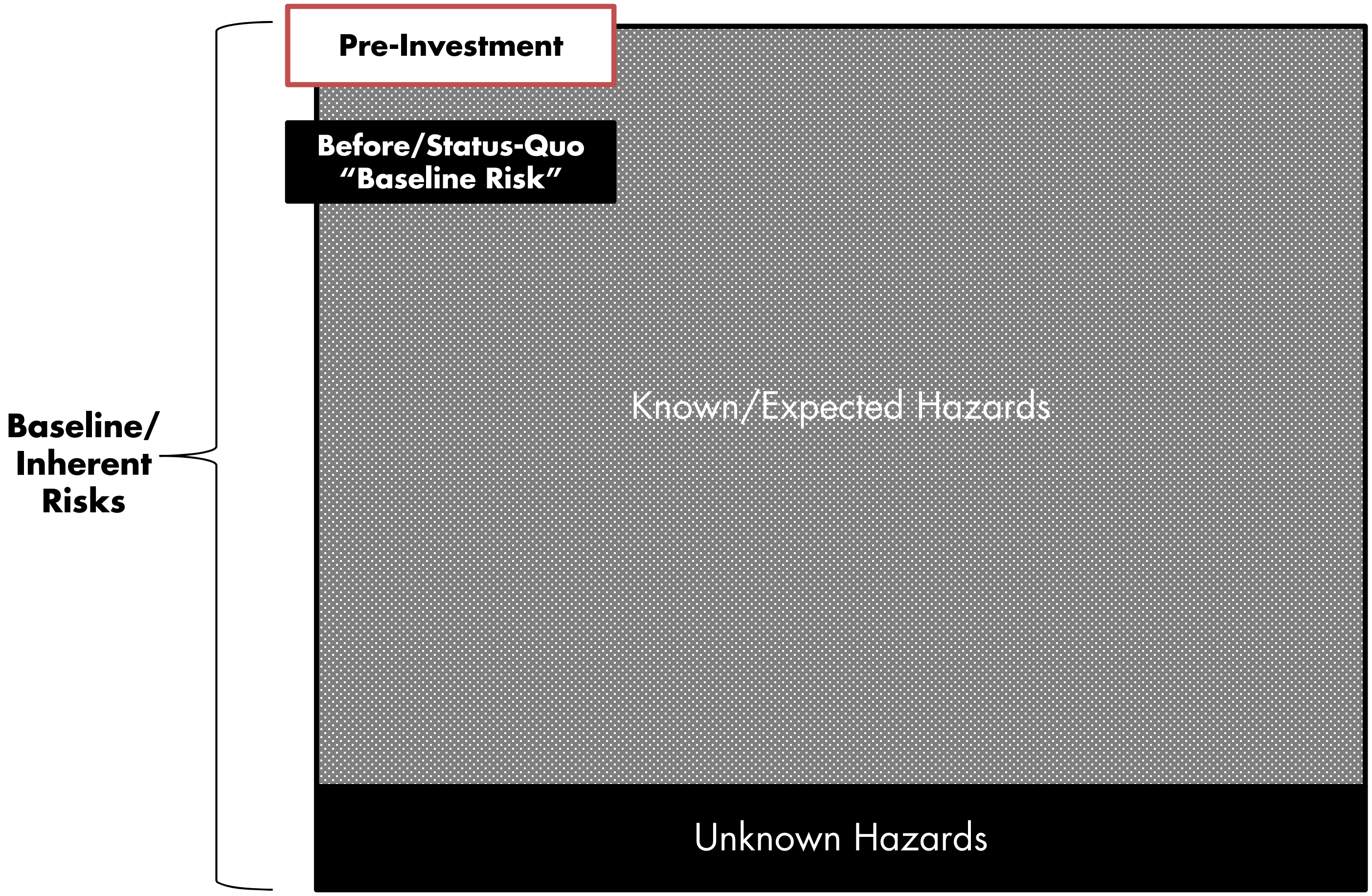
Investment Planning Risks Assessments

Hazards/Threats
- Fire
- Explosion
- Severe Weather
- Hazardous materials spill or release
- Mechanical breakdown
- Equipment condition
- Cyber Attack
- Physical Attack
- Theft and vandalism
- Obsolescence
- Inefficient processes
- Non-Compliance

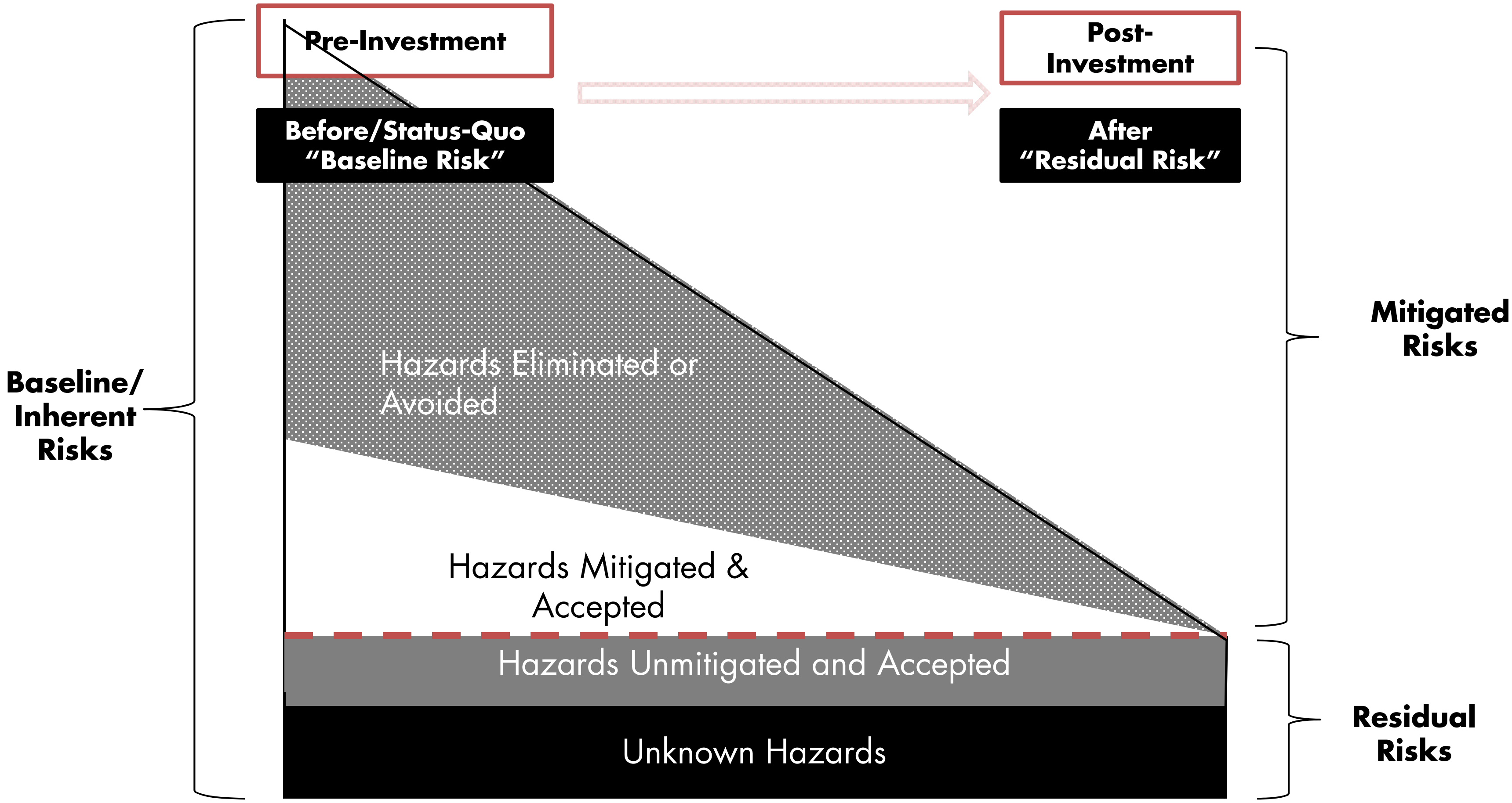
Assets/Objectives at Risk
- People
- Power system facilities
- Customer Relationship
- Systems/Equipment
- Information Technology
- Operational performance
- Business Operations
- Financial profile
- Regulatory and legal obligations
- Environment
- Company Reputation

Consequences
- Workforce/Public Injuries
- Performance and reliability
- Erosion of customer goodwill
- Environmental release/contamination
- Financial loss
- Loss of Shareholder confidence
- Regulatory credibility
- Regulatory compliance
- Fines, penalties and sanctions

Risk Informed Investment Decisions



Risk Informed Investment Decisions



Principle Risk Categories

Risk Category	Corporate Business Values/Objective

Financial Risk: The risk of financial loss to the organization's ability to earn, raise or access capital as well as costs associated with its transfer of risk.	• **Shareholder Value**
	  • Net Income
	  • Credit Worthiness

Operational Risk: The risk of direct or indirect loss or inability to provide core services, resulting from inadequate or failed internal processes, people and systems or from external events.
 	
Can be divided into 3 sub categories:
• Asset Risks impacting the assets required to do work, including Tx/Dx asset condition/configuration, IT and data risks, and environment risk.
• Human Capital Risks impacting the resources required to do the work, including Employee Injuries / Absenteeism, Outsourcing, Human Resources Uncertainty, etc.
• Execution Risks impacting the execution of work on schedule, scope, and budget; includes Cost and Productivity uncertainty, Work Program Accomplishment, Power System Security Risk etc.
	• **Reliability**
	• **Shareholder Value**
	  • Regulatory Compliance
	• **Environment**
	• **Productivity**
	  • Productivity (unit costs)
	  • Work Program Accomplishment
	• **Safety**
	• **Employees**

Reputational/Stakeholder Risk: The risk of significant negative public/ stakeholder opinion (customers, regulators, shareholders, industry associations, etc.) that results in a critical loss of confidence.	• **Customer**
	  • Customer Satisfaction
	  • OEB SQI
	• **Shareholder Value**
	  • Shareholder Confidence
	  • Public profile/reputation
	  • Regulatory credibility
	• **Safety**

Examples of Hazards/Threats

Natural

Meteorological
- Wind storm/ Tornado
- Hail/Snow/Ice Storm
- Forest fires
- Flood
- Extreme temperatures

Geological
- Earthquake
- Land/mudslide
- Space weather

Ecological
- Animals
- Birds

Technological

Internal
- Equipment failure/mis-operation / limitation
  - **Capacity** - Volume of demand exceeds design capacity
  - **Level of Service** - Functional requirements exceed design capability (spill containment, noise barriers)
  - **Mortality** - Asset deterioration reduces performance below acceptable level (Fire, Spill, Explosion, Structural collapse, etc.)
  - **Efficiency** - Operations costs exceed that of feasible alternatives
- Technology failure
- Structural failure
- Hazardous spills/releases

External
- Equipment failure/mis-operation (Customer owned)
- Train derailment

Human-Caused

Intentional
- Cyber incident
- Criminal incident
- Sabotage
- Activist incidents
- Civil unrest/disobedience
- Terrorism
- Non-Compliance

Unintentional
- Car crash
- Human error
- Aircraft incident
- Non-Compliance

Likelihood Assessments - Population

Incidence Rate = # of Incidents / Population at Risk — in a given period

Population Level Incidence Rate: Example: Illness

	2005	2006	2007	2008	2005- 2008 Total
Population	32,299,412	32,526,324	33,054,890	33,305,435	131,186,060
Incidents	1656	1003	832	1151	4642
Incident Rate (per 100,000 person years)	5.13	3.08	2.52	3.46	3.54

Incidence Rates are often expressed in a standard ratio to avoid the use of small decimals, for example:

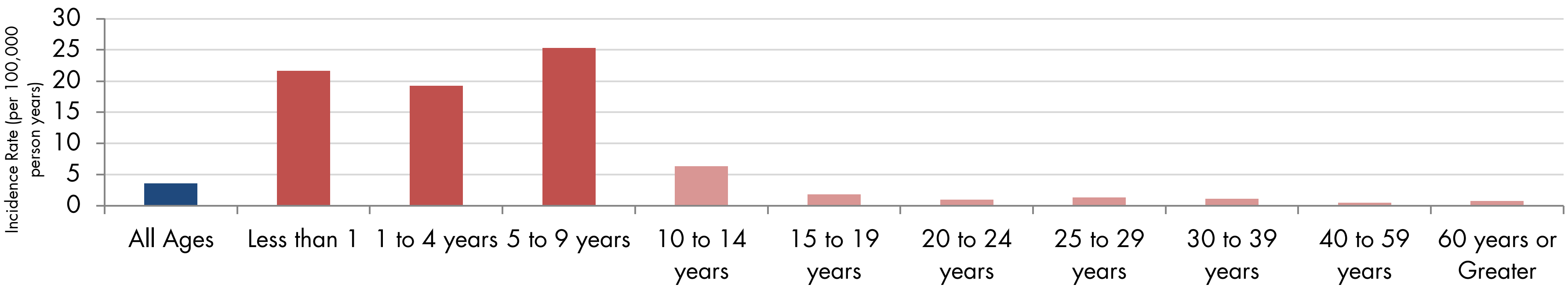
- Per Inventory Year
- Per station
- Per circuit km
- Per 100,000 people
- Etc.

Population level incidence rates can understate the likely impact of an event on a sub-population/cohort that shares similar characteristic/risk factors, including condition, location, configuration, vintage, etc.

Likelihood Assessments - Subpopulation

Sub - Population Level Incidence Rate:
Example: Illness

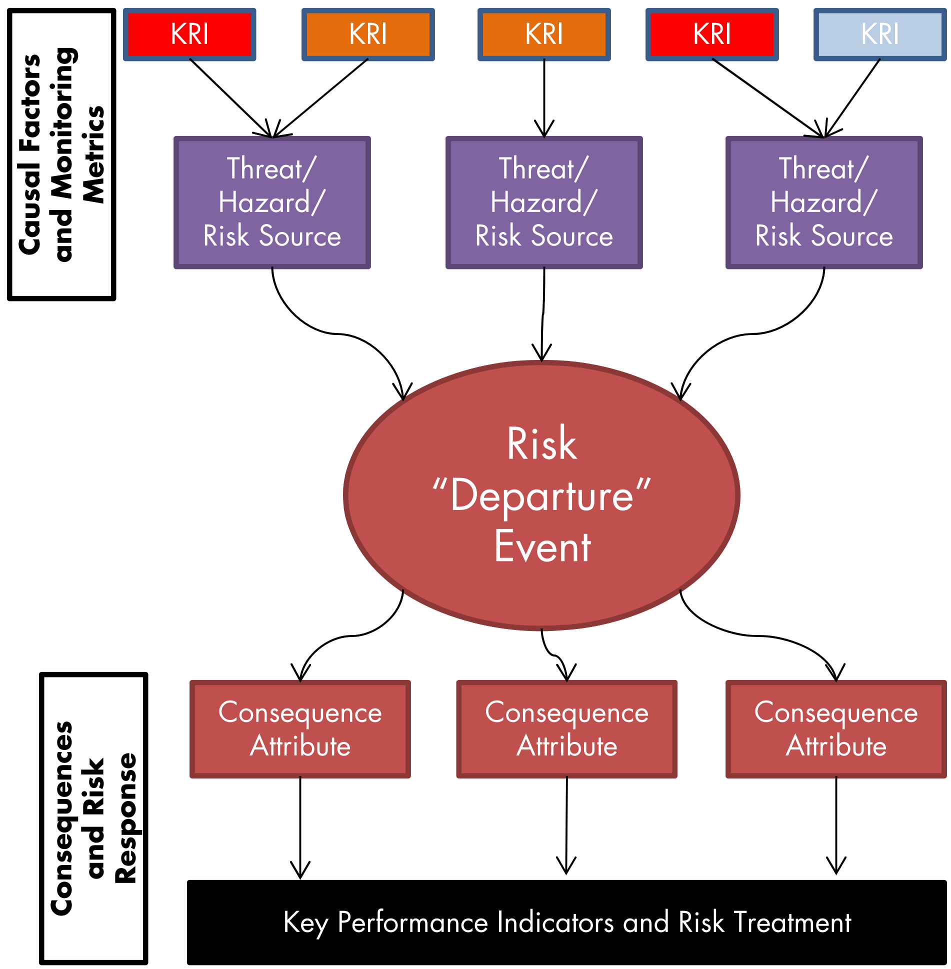
	Age Range									
	<1	**1 to 4**	**5 to 9**	**10 to 14**	**15 to 19**	**20 to 24**	**25 to 29**	**30 to 39**	**40 to 59**	**60+**
Population (2005-08)	1,422,252	5,588,321	7,282,328	8,293,731	8,885,541	9,045,680	8,860,305	18,050,949	39,545,455	24,211,500
Incidents (2005-08)	307	1073	1843	522	161	83	114	194	172	173
Incident Rate (per 100,000 person years)	**21.59**	**19.20**	**25.31**	6.29	1.81	0.92	1.29	1.07	0.43	0.71



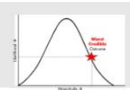
Role of Key Risk Indicators

Asset Analytics

- Presents key indices that may have an impact on Hydro One business values, including a composite index
- Draws attention to "at risk" and "vulnerable" asset areas for investment planning actions
- Does not provide a probability x consequence risk assessment
- One element/consideration in the risk assessment process; it can provide key insight into select risk event scenarios, but is not ultimately a risk assessment



Baseline Risk Assessment Documentation

Investment Detail Field	Required Contents	Templates
Risk Statement	Provide a risk statement that contains a hazard/threat, a departure event, an asset and a consequence. The narrative will provide background information considered relevant to understanding and appreciating the noted concerns.	Given that [**HAZARD**], there is a possibility of [**DEPARTURE EVENT**] adversely impacting [**ASSET/OBJECTIVE**], which can result in [**CONSEQUENCE**]  **Hazard:** The **current, fact-based situation** or environment that is causing concern, doubt, anxiety or uneasiness. **Departure Event:** Occurrence or **change of a particular set of circumstances**; unlike the Hazard Condition, the Departure Event is a statement about what might occur at a future time. **Asset/Objective:** The primary resource/element that is potentially impacted by the risk. **Consequence:** Description of the credible outcome of an event affecting the company's objectives (impact/magnitude).
Strength of Existing Controls	In absence of the proposed investment, what other controls are in place? Consider established corrective and demand programs, if applicable.	
Causal Factors	Describe the causal factors that contribute to the risk event.	
Context Statement	Document additional information that does not appear in the Risk Statement, including the "what, when, where, how and why" of the Risk by describing the risk indicators, circumstances, causal factors, uncertainties, and related issues. Provide data sources considered/consulted.	
Baseline Risk Assessment	Describe the consequence and likelihood of the Risk assessment and how was arrived at, including calculations.	
Risk Treatment	Describe what action, if any, should be taken to reduce the risk.	• Retain • Retain, but Change Mitigation • Increase • Avoid • Reduce likelihood • Reduce Consequence • Share

Risk Event Examples (Illustrative)

Allanburg Station Refurbishment

- Reliability
  - Given that [HAZARD: **the condition of the Allanburg TS T1 transformer has deteriorated as indicated by dissolved gas analysis**], there is a possibility of [DEPARTURE EVENT: **equipment failure leading to a prolonged forced outage**] adversely impacting [ASSET/OBJECTIVE: **operational performance**], which can result in [CONSEQUENCE: **unsupplied energy in the Niagara area**]

Birch Station Refurbishment

- Customer
  - Given that [HAZARD: **the condition of the Birch TS oil circuit breakers have deteriorated based on the increasing number of corrective and emergency work orders**], there is a possibility of [DEPARTURE EVENT: **equipment failure leading to a forced outage**] adversely impacting [ASSET/OBJECTIVE: **its customer Thunder Bay Hydro**], which can result in [CONSEQUENCE: **increased customer dissatisfaction with Hydro One**]

Distribution Submarine Cables

- Safety
  - Given that [HAZARD: **approximately 15% of the submarine cables fleet is in a deteriorated condition per asset condition assessments**], there is a possibility of [DEPARTURE EVENT: **corrosion of the protective cable armor, which can lead to neutral failure or water ingress**] adversely impacting [ASSET/OBJECTIVE: **public safety**], which can result in [CONSEQUENCE: **public injuries**]

Customer Connection

- Shareholder Value
  - Given that [HAZARD: **the Transmission System Code requires Hydro One to respond to customer requests for service**], there is a possibility that [DEPARTURE EVENT: **failing to connect a customer**] will adversely impact [ASSET/OBJECTIVE: **Hydro One's regulatory profile**], which can result in [CONSEQUENCE: **a finding of non-compliance**]

Risk Normalization

- Risk is assessed by several different planning groups, each with different experiences, preferences and tolerances for certain types of risks.
- Each group is vying for limited financial resources.
- Risk assessments are normalized using standardized, consistent templates:
  - Business Value Consequence Table (Impact of Outcomes)
  - Risk Matrix (Likelihood of Consequences)
  - AIP risk documentation (***NEW***)

Consequence →

Probability	Minor1	Minor2	Minor3	Minor4	Minor5	Moderate	Major	Severe	Catastrophic
Very Likely	75	200	500	1,250	3,000	7,500	20,000	50,000	150,000
Likely	38	100	250	625	1,500	3,750	10,000	25,000	75,000
Medium	15	40	100	250	600	1,500	4,000	10,000	30,000
Unlikely	5	12	30	75	180	450	1,200	3,000	9,000
Remote	1	2	5	13	30	75	200	500	1,500
Unexpected	0	0	0	0	0	0	0	0	0

Risk Level: Low | Medium | High

Objective	Consequences
Shareholder Value	
Safety	
Customers	
Reliability	Minor 1 → Catastrophic
Environment	
Employees	
Productivity	

2016 Risk Based Investment Planning Process

Document & Evaluate ⇨ **Calibrate** ⇨ **Optimize** ⇔ **Risk-Informed Discussions** ⇨ **Finalize**

- Risks for each investment are documented and assessed
- Investments are scored using risk matrix and consequence table

- Cross-LOB calibration ("challenge session") held
- Planning groups present their methodology, top risks and top investments
- Risk assessments are adjusted, as appropriate

- Investment Portfolio optimized based on risk assessments
- Outputs are validated
- Risk assessments are adjusted, as appropriate
- Investment Portfolio re-optimized, as appropriate

- Investment Portfolio finalized
- Included in Business Plan

Module 3A:
Hydro One Case Study

Case Study: E1C Pole Failure

Scenario:
- **<u>May 11, 2014</u>**: E1C 115 kV circuit (Ear Falls x Musselwhite CSS) and M1M 115 kV circuit (Musselwhite CTS) were automatically removed from service from line protection interrupting Slate Falls DS, Crow Lake DS. and Customers: Cat Lake MTS, Musselwhite CTS. Helicopter patrol revealed a downed pole on circuit E1C between Cat Lake MTS and Crow River DS. E1C/M1M was returned 28 hours later.

Consequence Assessments
Reliability:
- Energy not supplied (load interrupted): 442MWh [Slate Falls: 2MWh; Cat Lake: 3MWh; Crow River: 35MWh; Musselwhite: 401MWh]

Customer:
- Production losses: $1.1M
  - Duration: 28 hours; Daily Throughput: 3,350 t/day; Assumed gold concentration: 0.23 oz./t; Realized gold price: $1,265/oz.

Shareholder:
- Public Profile/Reputation re: effective stewardship of assets: Significant local attention; opinion leaders/customers publicly critical
  - Goldcorp representatives have called E1C the "worst performing line in the province" [Sudbury Mining Solutions]
  - The Northern Ontario Municipal Association (NOMA) and Common Voice Northwest lobby the government to 'loop' radial lines to ensure quality and quantity of supply

Case Study: E1C Pole Failure: Consequences

	Event	Minor 1: Noticeable disruption to results; manageable.	Minor 2: Noticeable disruption to results; manageable.	Minor 3: Noticeable disruption to results; manageable.	Minor 4: Noticeable disruption to results; manageable.	Minor 5: Noticeable disruption to results; manageable.	Moderate: Material deterioration in results; a concern; may not be acceptable; management response would be considered.	Major: Significant deterioration in results; not acceptable; management response.	Severe: Fundamental threat to operating results; immediate senior management attention.	Catastrophic: Results threaten survival of company in current form; potentially full time senior management response until resolved.
Customer	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Meets planned improvement in customer satisfaction survey results (as measured by scorecard).				Less than planned improvement in customer satisfaction survey results (as measured by scorecard).	Increase in number of customer complaints; Some increase in number of customers falling outside of "delivery point performance standards"; Moderate deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in at least one segment.	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; High level (CEO, COO, etc. X to Hydro One CEO's offi... Significant increase in number of customers falling outside of "delivery point performance standards"; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single segment.	Customer associations (AMPCO, etc.) step up lobbying efforts for stricter penalties against Hydro One; Increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase significantly; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) across multiple segments.	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically
Reliability	Transmission Unsupplied Energy Measured in MWh	< 12 MWh	12-30 MWh	30-120 MWh	120-250 MWh	250-600 MWh X	600-1500 MWh	1500-5000 MWh (e.g. In 2013, Armitage TS failure was 1,700 MWh and Manby TS failure was 3,400 MWh)	5000-10,000MWh	>10,000 MWh (for comparison, GTA flood in 2013 was 21,000 MWh).
Shareholder Value	Publice Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism					Credible letter(s) to Senior Management	X Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action	X Significant local attention; Several opinion leaders/customers publicly critical	Provincial media attention; most opinion leaders/customers publicly critical	National media attention; opinion leaders/customers nearly unanimous in public criticism

Introduction	Risk Overview	Asset Risk Management	Case Studies	Tx Events	Dx Events	Tool Kit Reference Points

Case Study: E1C Pole Failure: Likelihood

Considerations

- E1C is a radial115kV transmission circuit running from Ear Falls TS to Crow River DS
- Wood pole and cross-arm failures often result in direct outages
- Hydro One has approximately 40,500 wood pole structures
- Over the 2004-2013 period (10 years), there were:
  - approximately 140 forced outages as a result of wood pole failures, including cross-arms
  - of these, only 90 resulted in delivery point interruptions

Calculation

- Inventory Years = 10 years x 40,500 wood poles = 405,000 inventory years
- Forced Outage Rate = 140 interruptions / 405,000 years = 0.00035 occurrences/year = 1 Interruption every 2,857 inventory years
- Failure-Interruption Rate = 90 Events / 405,000 years = 0.00022 occurrences/year = 1 Event every 4,545 inventory years

Module 3B:
Sunflower Cove Case Studies

Sunflower Cove Water – Consequences and Likelihood

	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
Reliable supply – Water not supplied (annual)	>75,000m^3	30,000-75,000m^3	10,000 – 30,000m^3	1,000 – 10,000m^3	<1,000m^3
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

Rating	Likelihood Scale	Expectation of Event Frequency in years	Probability in Planning Period (5 years)
5	Very Likely	>1 in 2	> 95%
4	Likely	1 in 2 to 1 in 5	95% to 65%
3	Medium	1 in 5 to 1 in 20	65% to 25%
2	Unlikely	1 in 20 to 1 in 100	25% to 5%
1	Remote	<1 in 100	< 5%

Case Study 1: New Development

Scenario

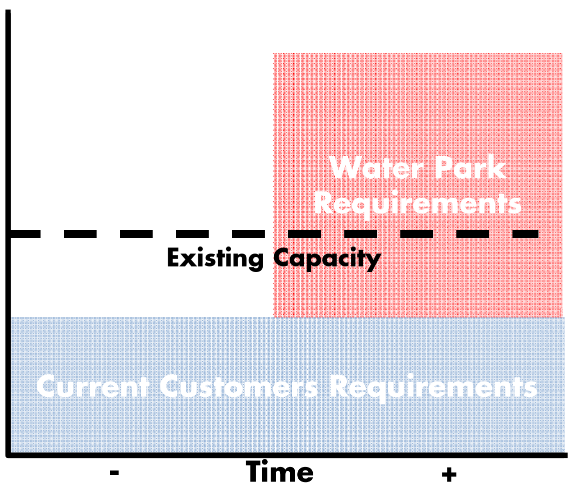
- A large company has noted its interest to develop a new Water and Amusement Park in Sunflower Cove because of its location on a major highway.
- The company has indicated that the waterpark will rely on city water supply and require a peak supply of water of 200m^3 per hour for 6 hours/day.
- Based on existing infrastructure in the area, and other customer requirements (100m^{3}per hour), Sunflower Cove can supply the new customer with, at most, 50m^3 per hour.
- Municipal bylaws state that Sunflower Cove must service new customers with water supply.
- The mayor's brother has recently been named VP of Business Development for the Water Park.

Recent Experience

- Because of its "prime location," Sunflower Cove has been approached by 8 theme parks in the last 10 years; despite strong proposals and sound local support, none of the proposals have been developed.
- Over that last 10 years, there have been 5 potential large customers per year that have announced plans to relocate to Sunflower Cove; only 2 of the potential customers have actually established operations.

Case Study: New Development (cont'd)

Risk = **Probability** ✖ **Consequence** ✖ **Mitigation Factor / Redundancy**



Risk Statement

Given that ,
there is a possibility that
will adversely impacting ,
which can result in

Likelihood Assessment

Consequence Assessment

Sunflower Cove Water – Consequence Table

	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
Reliable supply – Water not supplied	>75,00m^3	30,000-75,000m^3	10,000 – 30,000m^3	1,000 – 10,000m^3	<1,000m^3
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

Sunflower Cove Water Risk Matrix – New Development

	1 Minor	2 Moderate	3 Major	4 Severe	5 Catastrophic
Very Likely >1 in 2 years					
Likely 1 in 2 to 1 in 5 years					
Medium 1 in 5 to 1 in 20 years					
Unlikely 1 in 20 to 1 in 100 years					
Remote 1 in 100 to 1 in 500 years					
Unexpected Less than 1 in 500 years					

Case Study: Asset Renewal

Scenario

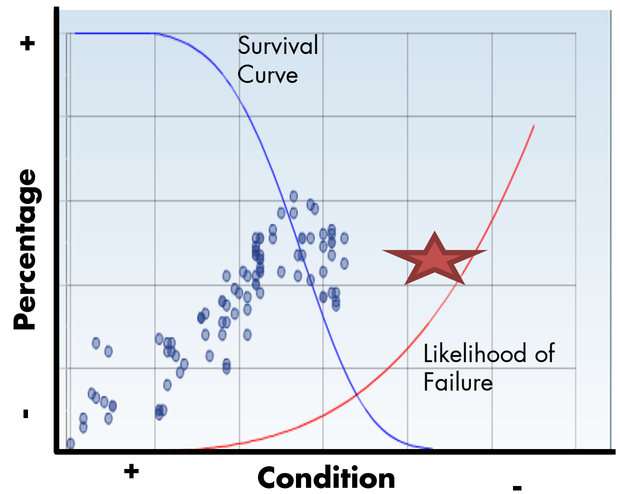
- The city of Sunflower Cove has approximately 6,000 km of water mains, divided into approximately 6,000 segments.
- Sunflower Cove grew rapidly during the 1950s and 1960s and considerable infrastructure was built to accommodate the growth.
- Approximately 2,000 km of ductile iron water mains were built during this time, a medium which has a typical service life of 50 years.
- Recent condition assessment and infrared studies have shown that the structural integrity of the 60 year old ductile iron constructed "trunk", serving a number of major customers that relies on a the trunk for consumption, heating, and cooling, is deteriorating.

Recent Analysis

- Citywide, the city experiences approx. 1,300 water main segment breaks per year.
- Over the last 5 years, 65% of failures occurred in ductile iron pipes, greater than 50 years old that were rated in poor condition prior to their failure.
- Most breaks are repairable, however about 5% of failures are considered catastrophic and require full replacement.

Case Study: Asset Renewal (cont'd)

Risk = **Probability** ✖ **Consequence** ✖ **Mitigation Factor / Redundancy**



Risk Statement

Given that [],
there is a possibility that []
which will adversely impact [],
which can result in []

Likelihood Assessment

Consequence Assessment

Sunflower Cove Water – Consequence Table

	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
Reliable supply – Water not supplied	>75,00m³	30,000-75,000m³	10,000 – 30,000m³	1,000 – 10,000m³	<1,000m³
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

Sunflower Cove Water Risk Matrix – Asset Renewal

	1 Minor	2 Moderate	3 Major	4 Severe	5 Catastrophic
Very Likely >1 in 2 years					
Likely 1 in 2 to 1 in 5 years					
Medium 1 in 5 to 1 in 20 years					
Unlikely 1 in 20 to 1 in 100 years					
Remote 1 in 100 to 1 in 500 years					
Unexpected Less than 1 in 500 years					

Appendix

Module 4:
System Events: Transmission

Case Study: Bruce A Breaker Failure

Scenario:

- **<u>July 26, 2014</u>**: OGCC received a Bruce "A" T2L27 230 KV air blast breaker trip circuit fail and low air pressure alarm. The low air pressure alarm cleared but the breaker could not be opened from control. In order to remove the stuck breaker from the Grid it was necessary to remove the zone which included Owen Sound T5 & T3, 230 KV circuit B27S and Bruce A G2 generator (730 MW).
- T2L27 was isolated and circuit B27S was restored ~4.5 hours later.
- Bruce A G2 was restarted 3 days later.

Reliability:

- Energy not supplied (generation constrained by Tx): ~3,285MWh (based on configuration limitations – 730MW x 4.5hrs)
- Impact: Major

Customer:

- Major Production losses: ~52,560MWh @ $75/MWh (per OEB RPP forecast – April 2014) = $3.9M
- Impact: Major

Case Study: E1C Pole Failure

Scenario:
- **May 11, 2014**: E1C 115 kV circuit (Ear Falls x Musselwhite CSS) and M1M 115 kV circuit (Musselwhite CTS) were automatically removed from service from line protection interrupting Slate Falls DS, Crow Lake DS. and Customers: Cat Lake MTS, Musselwhite CTS. Helicopter patrol revealed a downed pole on circuit E1C between Cat Lake MTS and Crow River DS. E1C/M1M was returned 28 hours later.

Reliability:
- Energy not supplied (load interrupted): 442MWh [Slate Falls: 2MWh; Cat Lake: 3MWh; Crow River: 35MWh; Musselwhite: 401MWh]
- Impact: Minor5

Customer:
- Major Production losses: $1.1M
  - Duration: 28 hours; Daily Throughput: 3,350 t/day; Assumed gold concentration: 0.23 oz./t; Realized gold price: $1,265/oz.
- Impact: Major

Shareholder:
- Public Profile/Reputation re: effective stewardship of assets: Significant local attention; opinion leaders/customers publicly critical
  - Goldcorp representatives have called E1C the "worst performing line in the province" [Sudbury Mining Solutions]
  - The Northern Ontario Municipal Association (NOMA) and Common Voice Northwest lobby the government to 'loop' radial lines to ensure quality and quantity of supply
- Impact: Major

Case Study: Hanmer T6 Failure

Scenario:
- **Feb 15, 2012**: 500/230KV Autotransformer Hanmer T6 was automatically removed from service initiated by differential and/or gas protection. The white phase tank ruptured releasing approximately 4000 gallons of oil which was contained. DFR's operated at Mississagi, Holden, Widdifield, Essa, Dymond, Hanmer, Porcupine and Lakehead SVC. Several mining customers in the area (Xstrada, Nickel Rim, Lockerby) reported the voltage fluctuation but did not report any production impact at the time. No load loss.

Reliability:
- Energy not supplied (load interrupted): 0
- Impact: Minor1

- Equipment Unavailability: 5424 hours [Failure: Feb 15, 2012; Replacement Start-Up: Sept 29, 2012] – 0.1%
  - ~5424 hours unavailable; total annual inventory hours: 735 units x 365 days x 24 hours = 6,438,600 hours
- Impact: Moderate

Environment:
- Adverse Environmental Impact: Significant spill/release with impact on Hydro One property only: ~7500 L of mineral oil released
- Impact: Moderate

Case Study: Sarnia Scott Security

Scenario:

- **<u>Jan 21, 2012</u>**: At 5:14am, two power transformers at Hydro One's Scott Transformer Station (TS) in Sarnia tripped off due to an intruder operating blocking switches that activated the differential protections causing the loss of 160MW of load in the Sarnia/Lambton area. The station was restored to normal operating condition and all power was returned before 8:00 am.

Reliability:

- Energy not supplied: Total load loss of approx. 165MW; with staggered restoration, approximately 325MWH of energy was not supplied
- Impact: Minor5

Customer:

- Large and Mid Customers: Major Chemical Valley customers, including Suncor , British Petroleum, and Imperial Oil, were forced to shutdown
- Impact: Major

Shareholder:

- Public Profile/Confidence: Correspondence between the Mayor of Sarnia and the Minister of Energy; significant media attention
  - CBC: "Hydro One break and enter shuts down chemical valley" (Jan 24, 2012)
  - London Free Press: "Man arrested in power outage" (Jan 23, 2012)
  - Sarnia this week: "Bradley's Hydro meltdown" (Jan 29, 2012)
  - CBC: "Hydro One ups security in Sarnia after break-in" (Mar 13, 2012)
- Impact: Moderate to Severe

Module 5:
System Events: Distribution

Case Study: CIS Recovery

Scenario:

- Within the first 30 days post CIS billing system go-live it became apparent that there were legacy system/data issues as well as issues associated with the new billing processes and timelines that were causing a higher than expected number of 'estimated' bills, billing exceptions and 'no-bills'. These billing challenges eventually resulted in an investigation into the billing and customer service practices at Hydro One by the Provincial Ombudsman in February of 2014.

Customer:

- Residential and Small Business Customers: Increase in Customer Satisfaction with service quality
  - Exponential increase (>30%)in call centre volumes [Severe]
    - Pre-CIS Billing Related Call Centre Calls: (May 2013): 55,147
    - Post-Go Live Billing Related Call Centre Calls: (June 2013): 84,966 [54% Increase]; (September 2013):73,000 [32% Increase]
  - Exponential increase to escalated complaints (MPPs, OEB, Ombudsman) [Worst Case]
    - Customer Relations Centre Backlog(Escalated MPP/OEB complaints): 300 (May 2013) to 691 (December 2013)
    - Ombudsman Complaints: : 232/328(2011/12); 6,961/3,499 (2013/14)
- Impact: Severe to Catastrophic

Shareholder:

- Public Profile/Confidence: Provincial and National media attention; most opinion leaders publicly critical
  - National Post: "Like wrestling with a slippery pig: Ontario Ombudsman to investigate Hydro One" (Feb 4/2014)
  - Ottawa Sun: "Hydro One stories will shock you" (Feb 9/2014); "Hydro One horror stories" (Feb 15/2014)
- Impact: Severe to Catastrophic
- Cost Impact: Customer Service Recovery resulted costs of approximately $88M (inclusive of bad debts)
- Impact: Major

Productivity:

- Failure to meet unit costs*: $88M OM&A increase: approximately 15% increase to unit costs [*Recovery excluded from 2014 Scorecard]
- Impact: Worst Case

Case Study: Kirkland Lake Voltage Conversion and 44kV Loop

Scenario:
- The Town of Kirkland Lake, an urban area of approximately 3000 customers, is experiencing strong economic growth, with expected load growth due to new industry. Kirkland Lake specifically requires additional distribution feeder capacity to meet forecasted commercial load growth; additionally there are reliability concerns due to the lack of a 44kV loop feed; this work is expected to reduce the average outage frequency from 7.3 to approximately 1.4 interruptions per year.

Reliability:
- Current Risk: 3000 customers x 7.3 Interruptions = 21,900 interruptions
- Impact: Minor 2
- Residual risk: 3000 customers x 1.4 Interruptions = 4,200 interruptions
- Impact: Minor 1

Shareholder:
- Public Profile/Confidence: Insufficient capacity to supply new loads due to the expansion of local mines could generate significant local attention or result in credible correspondence to elected provincial officials (Ministry of Energy, Ministry of Northern Development and Mines, etc.).
- Impact: Moderate to Major

Case Study: Owen Sound Pole Failure

Scenario:
- A pole at the back entrance to Owen Sound's Harrison Park was knocked over and it leaked about 160L of oil into the river above the mill dam. The transformer that broke was from the 1970s, when PCBs (polychlorinated biphenyls) were often used; the spilled oil contained 11 parts per million of PCBs.

Reliability:
- Duration of distribution outages: *Assumption*: Average of 191 customers are impacted by a pole outage, resulting in an average of 9 hour outage: ~1,719 Interruption Hours [<1 million customer interruption hours]
- Impact: Minor1

Customer:
- Residential and Small Business Customers: Outages/Reliability is not the main source of dissatisfaction for RSB customers; 9 hour outage is less than multi-year current average of ~14 hours; impact of 191 customers(~0.01% of total) unlikely to impact survey results
- Impact: Minor1

Shareholder:
- Public Profile/Confidence: Incident may result in credible letters to Ministry of Environment and Climate Change or Environment Canada regarding impact of PCBs on local waterways
- Impact: Moderate

Environment:
- Adverse Environmental Impact: Minor local offsite impact; PCB content below EC limits
- Impact: Minor5

Case Study: Brockville Pole Failure

Scenario:
- A transport truck, while trying to negotiate the narrow side streets of Brockville, collided with a hydro pole, knocking down the pole and leaving 344 Hydro One customers without power between 6:10 pm and 2:55am.

Reliability:
- Duration of distribution outages: 344 customers are impacted by the outage for approximately 9 hours : ~3,096 Interruption Hours [<1 million customer interruption hours]
- Impact: Minor1

Customer:
- Residential and Small Business Customers: Outages/Reliability is not the main source of dissatisfaction for RSB customers; a 9 hour outage is less than multi-year current average of ~14 hours; impact of 344 customers(~0.03% of total) unlikely to impact survey results
- Impact: Minor1

Shareholder:
- Public Profile/Confidence: Passing coverage in local Brockville Recorder and Times; neutral, fact based tone
- Impact: Minor1

Case Study: Damaged Insulators in the United Counties of Leeds and Grenville

Scenario:
- Damaged insulators led to an outage affecting 3,398 customers in Brockville and the Leeds and Thousand Islands area between 11:36 am and 8pm.

Reliability:
- Duration of distribution outages: 3,398, mainly residential, customers are impacted by the outage for approximately 8.5 hours : ~28,883 Interruption Hours [<1 million customer interruption hours]
- Impact: Minor1

Customer:
- Residential and Small Business Customers: Outages/Reliability is not the main source of dissatisfaction for RSB customers; a 8.5 hour outage is less than multi-year current average of ~14 hours; impact of 3,398 customers(~0.28% of total) unlikely to impact survey results
- Impact: Minor1

Shareholder:
- Public Profile: Passing coverage in local Brockville Recorder and Times; neutral, fact based tone; Eastern Ontario Wardens Caucus has previously raised issues with the Minister of Energy about the reliability of the Hydro One system in this region and frequent, often lengthy, outages
- Impact: Minor1 - Moderate

Case Study: Dx Vegetation Management

Scenario:

- Hydro One utilizes a proactive line clearing program to manage the edges of its right-of-way by removing damages or diseased trees that pose a threat of falling into a line and by pruning trees to maintain clearances to energize facilities. Tree contacts are a leading cause of customer outages.

Reliability:

- 2014 Performance (Residual with preventative program in place, per 2014 OEB Yearbook):
  - Duration of Distribution Outages: ~4.4M customer hours
  - Frequency of Distribution Outages: ~800k customer interruptions
- Impact: Minor 4 (Duration) to Moderate (Frequency)

Customer:

- Residential and Small Business Customers: For RSB customers, costs/rates continue to be the principle source of dissatisfaction; deteriorating conditions unlikely to have a significant impact in the near-term
- Impact: Minor 1 – Moderate
- Large and Mid Customers: Reliability, restoration and power quality continue to main sources of dissatisfaction; potential increase of customer complaints due to production losses
- Impact: Moderate to Major

Shareholder:

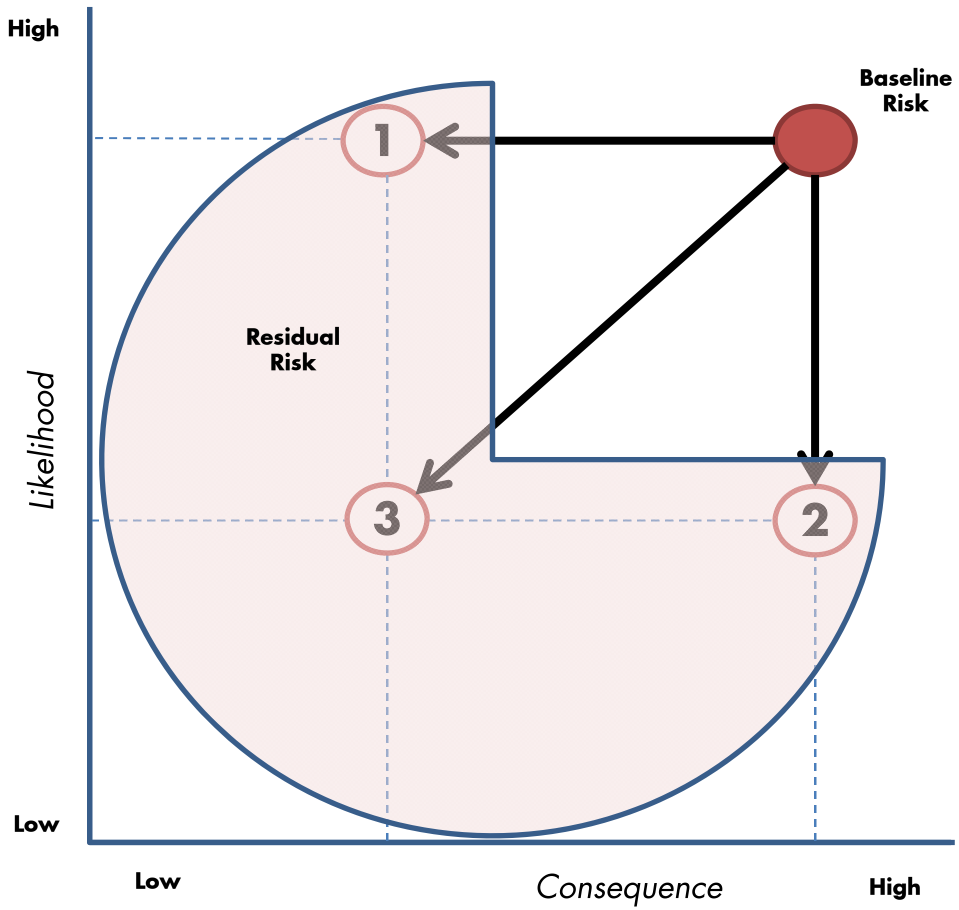
- Credibility with Regulators: Absence of a preventative vegetation management program may prompt the regulator to raise concerns re: Hydro One's ability to "maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability", consistent with the Distribution System Code
- Impact: Major

Module 6:
Tool Kit Reference Points

Risk Assessment Terminology

Terminology	Description
Risk	Effect of Uncertainty on Objectives (ISO 31000:2009)
Hazard Condition	The current, fact-based situation or environment that is causing concern, doubt, anxiety or uneasiness.
Departure Event	Occurrence or change of a particular set of circumstances; unlike the Hazard Condition, the Departure Event is a statement about what might occur at a future time.
Asset	The primary resource/element that is potentially impacted by the risk.
Consequence	Description of the credible outcome of an event affecting the company's objectives (impact/magnitude).
Risk Tolerance	The organization's or stakeholder's readiness to bear the risk in order to achieve its objectives. Hydro One's risk tolerances are established annually by Senior Management and Board of Directors.
Likelihood	The chance of something happening (probability/frequency.
Risk Treatment	The process to address the risk; may include accepting, increasing, or decreasing the risk exposure.
Control	A measure that can modifying risk
Baseline (Inherent) Risk	The risk of doing nothing
Residual Risk	The risk that remains after controls are taken into account
Risk mitigation	The reduction in risk (baseline vs. residual) as a result of a risk treatment and control (usually an investment).

Risk Treatment and Value Creation



- Value Framework is the basis for how investments are valued
- The change between Baseline Risk and Residual Risk is the risk mitigated
- Value is generated through risk mitigated or financial benefits produced by an investment
- Different controls/investment alternatives may mitigate risk in different ways, creating variable value outcomes
- Some alternatives may **reduce the consequence (1)**, some may **reduce the likelihood (2)**, others may **do both (3)**.

Hydro One Corporate Risk Consequence Table

Objective		Attribute	Description	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
SHAREHOLDER VALUE	1	Net Income	Net Income Shortfall (after tax, in one year)	>$300M	$100M-$300M	$25M-$100M	$5M-$25M	<$5M
	2	Shareholder confidence	Owner/ shareholder intervention in Hydro One operations	Complete loss of confidence; shareholder agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; shareholder imposes substantial reduction in Hydro One scope and mandate	Extensive loss of confidence; shareholder agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced	Material erosion in confidence; shareholder agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board	Confidence in question; owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain	Some concern with management decisions; occasional requests from owner for details
	3	Public Profile /Reputation re effective stewardship of assets	Negative Media Attention; Opinion leader and Public Criticism	National media attention; opinion leaders/customers nearly unanimous in public criticism	Provincial media attention; most opinion leaders/customers publicly critical	Significant local attention; Several opinion leaders/customers publicly critical	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action	Credible letter(s) to Senior Management
	4	Maintain credibility with regulators	Lack of Credibility or poor relationships with Regulators & Reliability Authorities (OEB/ IESO/NERC/NPCC/WSIB etc.)	General loss of Credibility; Intrusive Involvement	Some loss of Credibility; Excessive Involvement	Some Concerns re: Competence; Difficult Demands	Increase in Reporting Detail and Frequency (for HOI only)	Balanced; some challenges
	5	Comply with regulations	Regulatory Non Compliance or Sanction	Conviction with incarceration of staff	Conviction or a regulatory finding of non-compliance with major fine ("major" means >30% of maximum fine under relevant legislation or regulation, or an unusually high/ unprecedented amount for the industry)	Conviction or a regulatory finding of non-compliance with minor fine ("minor" means <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high or unprecedented in the industry)	Regulatory order, and/or a financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry	Regulatory warning, conditional closeout without sanctions
	6	Credit Worthiness	Change in liquidity, financial ratios or risk	Event of Default; Unable to raise any capital due to credit rating	Credit rating downgrade to below "investment grade;" Unable to raise full amount required capital	Credit rating downgrade that impacts costs in a major way or borrowing capability.	Hydro One Inc. put on credit "watch"	Credit Rating agencies and bondholders express concern
SAFETY	7	Employee/Contractor Workforce/Health and safety	Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries	Employee/contractor fatality or major permanent disability due to failure of managed system	Employee/contractor critical injury due to failure of managed system; Significant deterioration in health and safety performance	No improvement in health and safety performance	Less than planned improvement in health and safety performance	Safety targets met, but minor concerns regarding future performance
	8	Public Safety	Public Injuries (with Hydro One at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries	No Change
CUSTOMERS	9	Large and Mid Customers (Industrials, LDCs, Tx & Dx Generators)	Increase in customer dissatisfaction with Hydro One	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically Hydro One loses suport to vie for large TX projects due to Large Customer Dissatisfaction	Customer associations (AMPCO, etc.) step up lobbying efforts for stricter penalties against Hydro One; Increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase significantly. Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) across multiple segments	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; high level (CEO, COO, etc.) calls to Hydro One CEO's office Significant increase in number of customers falling outside of "delivery point performance standards" Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single	Increase in number of customer complaints. Some increase in number of customers falling outside of "delivery point performance standards" Moderate deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in at least one segment	Less than planned improvement in customer satisfaction survey results
	10	OEB Service Quality Indices	Failure to Meet Service Quality Indices	Achieve only 25% (to 66%) of Overall Expected Performance	Achieve only 67% (to 79%)of Overall Expected Performance	Achieve only 80% (to 89%) of Overall Expected Performance	Achieve only 90% (to 94%) of Overall Expected Performance	Achieve only 95% (to 100%) of Overall Expected Performance
	11	Residential and Small Business Customers	Increase in customer dissatisfaction with Hydro One service quality	Letters and complaints to MPP's escalate - leading to regulatory/external investigation; Significant numbers of customers begin to default on bill payments	Exponential (>30%) increase in: - call centre volumes (not storm related) - complaints received by field staff; - time and effort to resolve Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard)	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard)	Slight deterioration in mass market customer satisfaction as per survey response (as measured by scorecard)	Less than planned improvement in mass market customer satisfaction as per survey response (as measured by scorecard)
RELIABILITY	12	Transmission Reliability - acute events (excluding "abnormal" weather events*)	Transmission unsupplied energy (due to a single acute event or outage)	>10,000 MWh (for comparison, GTA flood in 2013 was 23,000 MWh)	5000-10,000 MWh	1500-5000 MWh (for example, Armitage failure was 1700 and Manby was 3400 MWh)	600-1500 MWh	<600 MWh
	13	Transmission Reliability - system performance over 5 years (excluding "abnormal" weather events*)	Deterioration in Tx system reliability (over the next 5 years, compared to benchmarked comparables)	Deterioration to third quartile at any time in 5 year period	Deterioration to second quartile for more than one year in the 5 year period	Deterioration to second quartile for only one year in the 5 year period	Deterioration in reliability relative to current performance (but still within first quartile) for more than one year in the 5 year period	Deterioration in reliability relative to current performance (but still within first quartile) for only one year in the 5 year period
	14	Distribution Reliability - system outages in one year (excluding "abnormal" weather events*)	Duration of Dx Outages Measured in Interruption hours (Number of customers x duration of outage)	>15 million customer interruption hours (equivalent to SAIDI of >12.5 hrs)	10 million to 15 million customer interruption hours (equivalent to SAIDI of 8.3 to 12.5 hrs)	8 million to 10 million customer interruption hours NB current performance is 8.8 and 5 year avg is 8.4 (equivalent to SAIDI of 6.7 to 8.3 hrs)	7 million to 8 million customer interruption hours (equivalent to SAIDI of 5.4 to 6.7 hrs)	<7 million customer interruption hours (equivalent to SAIDI of <5.4 hrs)
ENVIRONMENT	15	Environmental Performance	Adverse Environment Impact or emission	Widespread offsite impacts (eg. Regional or Municipal water supply); Carbon footprint / greenhouse gas gets substantially larger relative to work program and more visible to interested stakeholders	Multiple local offsite impacts (eg. Multiple residential properties or private water supplies); Carbon footprint / greenhouse gas gets somewhat larger relative to work program and more visible to interested stakeholders	Significant local offsite impact (eg. a public thoroughfare); No real improvement relative to work program in carbon footprint / greenhouse gas initiatives	Minor local offsite impact (eg. a single residential property or private water supply); Significant spill/release with impact on Hydro One Inc. property only; Somewhat less than hoped improvement relative to work program in carbon footprint / greenhouse gas	Minor impact on Hydro One Inc. property only' Marginally less than hoped improvement relative to work program in carbon footprint / greenhouse gas
EMPLOYEES	16	Employee skills and engagement: developing, retaining, attracting and competencies	Change in employee engagement survey results.	Sharp deterioration in employee survey results	Modest decline in employee survey results	No improvement achieved in employee survey results	Much Less-than-planned improvement achieved in employee survey results	Less-than-planned Improvement Achieved in Employee Survey Results
PRODUCTIVITY	17	Productivity	Failure meet Unit Cost targets per plan	Unit Costs increase by > 10%	Unit Costs increase by 6% - 10%	Unit Costs increase by 2% - 5%	Unit Costs increase by 1% - 2%	Unit costs increase by < 1%
	18	Work Program Accomplishment, including Tx Plan short term initiatives	Work Program Shortfall (per HOI plan and commitments)	- <50% of total work program or in service capital completed - <85% of total work program OM&A completed	- 50%-69% of total work programs or in service capital completed - 85%-90% of total work program OM&A completed	-70%-84% of total work programs or in service capital completed - 90%-95% of total work program OM&A completed	- 85%-94% of total work programs or in service capital completed - 95%-98% of total work program OM&A completed	- >95% of total work programs or in service capital completed - >98% of total work program OM&A completed

Corporate Risk Consequence Table (Corporate Risk Hydro-Net site) (link in Presentation Mode)

Shareholder Value: Key Considerations

<u>Considerations</u>

- How will this decision impact Net Income?
- Will this decision result in negative media attention? Where will it be covered? What tone will the coverage take?
- Will this decision have regulatory or legal implications?
- Are there compliance obligations?
- Have regulatory commitments been made?

Strategic Objective:
Maintaining a commercial culture that increases value for our Shareholder.
For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our Shareholder. We will pursue growth opportunities through LDC consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution and transmission footprint.

Shareholder Value/Commercial Culture: Scorecard Calculations

In-Service Capital - Tx	=	YTD Tx Actual ISA / YTD Tx ISA Plan
In-Service Capital – Dx	=	YTD Dx Actual ISA / YTD Dx ISA Plan

Net Income = Revenue - Operating and fixed costs - Taxes

Shareholder Value: Financial and Public Profile

- One Year Net Income Shortfall:

Unplanned (incremental) OM&A expenditures	Failure to meet In-Service target (equity portion)
$1M incremental OM&A (without redirection/accommodation) would reduce NI by $1M	$1M NI is driven by approximately $27.2M of ISA [$27.2M x 40% deemed equity x 9.19% (ROE)] [2016 Cost of Capital]

- Public Profile/Reputation
  - Sources of news media focus

National *(Globe and Mail, National Post, Toronto Star)*	**Local** *(Timmins Press, Northumberland News, EMC, Ontario Farmer, Renfrew Mercury, Ottawa Citizen, Peterborough Examiner, etc.)*
• Public investigations (Ombudsman, Auditor General, etc.) • Billing issues/practices • Privatization • Procurement practices • Compensation/Pensions • Large urban outages (Toronto – Manby Breaker/Richview Flood) • Broad Ontario electricity sector policy	• Impacts to large customers (Sarnia (Imperial Oil)[Tx], Huntsville (Kimberly-Clark)(Dx) • Costs • Local outage/power quality issues • Smart Meters • Distributed generation • Compensation • Major projects (Clarington, Bruce to Milton, etc.) • Broad Ontario electricity sector policy • Community involvement/commitments

Shareholder Value: Regulatory Credibility and Compliance

Regulatory Bodies:

- Will inaction result in the violation of a code, statute or standard? Is there an opportunity to submit an action plan or self report the violation?

- Ontario Energy Board (OEB)
  - Licencing
  - Codes (Transmission/Distribution/Affiliate Relationship/Standard Supply Service/etc.)
  - Rate Setting
  - Performance assessments
- Independent Electricity System Operator (IESO)
  - Market Rules and Manuals
  - Compliance monitoring and enforcement
- North American Electricity Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC)
  - Reliability standards
- Workplace Safety & Insurance Board (WSIB)
- Electrical Safety Authority (ESA)
  - O. Reg 22/04
- Ministry of Environment and Climate Change (MOECC)
  - Environmental Assessments
  - Environmental Compliance Approvals (Drainage/Air/Noise/etc.)

Regulatory Commitments:

- Is there an explicit commitment to a regulatory body? Will inaction result in the commitment not being met?

- Adherence to codes/standards/regulations
- In-Service
- Delivering Work Program commitments, including. Major projects
- Service Quality Indices
- Performance/unit costs

The above list in not intended to be comprehensive, but to provide a sense of the regulated environment Hydro One operates within.

Shareholder Value: Public Profile, keep in mind...

An investment that mitigates risk to reliability may expose the company to other risks (public profile, etc.)

Hydro One

- Bruce x Milton
  - "Hydro One turns farm into hellhole" [Local/Regional Quebecor Media, February 18, 2012]

- Clarington TS
  - "Clarington transformer called "dangerous precedent" [Toronto Star, September 24, 2014]
  - "Hydro One, Clarington residents clash over proposed transformer station" [Toronto Star, August 21, 2014]
  - Clarington Town Council resolutions opposing the station/recommending greater scrutiny

Ontario Government/Ontario Power Authority

- Southwest GTA (Oakville) Gas Plant
  - "Oakville brings in Erin Brockovich to fight power plant" [Toronto Star, October 1, 2010]
  - "Worried Liberals pull plug on Oakville gas plant" [Toronto Star, October 7, 2010]
  - "Oakville gas plant plan axed" [National Post, October 8, 2010]

Toronto Transit Commission

- "TTC Construction creates traffic headache on Queen" [National Post, July 13, 2012]
- "Kingston Road construction to cause headaches for drivers" [City News, June 24, 2013]
- "TTC's Leslie Street construction 'a real mess'" [Inside Toronto, April 17, 2014]

Customer Satisfaction: Key Considerations

Considerations

- How will this decision impact customer satisfaction?
- Consider relationship between number of customers impacted and the total customer pool.

- Transmission
  - What may cause an increase in customer dissatisfaction?
    - What are characteristics of increased dissatisfaction? [Deterioration of survey results, increased complaints (AE, executive, shareholder, etc.), production (manufacturing/generation) losses, missed delivery point performance standards, lawsuits, etc.]

- Distribution
  - What may cause an increase in customer dissatisfaction?
    - How might increased dissatisfaction manifest itself? (Deterioration of survey results, increased complaints to MPPs, increased call centre volume, increase to bad debt/customer defaults, etc.)
  - What may cause Hydro One to miss its OEB Service Quality Indices?
    - By how much would the target be missed by?

Strategic Objective:
Satisfying our customers.
We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.

Customer Satisfaction: Scorecard Calculations

Tx Customer Satisfaction = $\dfrac{\text{\% Satisfied/Agreed: Large Tx Q1 + Large Tx Q2 + OGCC Q1 + OGCC Q2}}{4}$

Transmission

- **Large Tx Q1**: How would you rate H1 on: Keeping Commitments
- **Large Tx Q2**: How would you rate H1 on: Making Decisions Promptly
- **OGCC Q1**: Please think about the staff at Ontario Grid Control Centre. Please indicate how much you agree or disagree that the staff understand your needs
- **OGCC Q2**: How satisfied are you with Ontario Grid Control Centre's procedures on planned outages.

Distribution

- Power outage handling
- Agent handled call satisfaction
- Forestry
- Lines New Connect/Upgrade
- My Account
- Large Distribution Accounts
- Distributed Generation Customers (OEB new connections milestones met)

Dx Customer Satisfaction = $\dfrac{\text{\% Satisfied/Agreed: Outage Handling + … + new Connect + … + DG}}{7}$

Customer – Top Level Tx Satisfaction

hydro one

Attribute	Who they are?	How do they feel? (2013)	How do they feel? (2014)	How do they feel? (2015)	Main Issue to address in 2015 (trend 2013 2014 2015)

Large and Mid Customers	Transmission connected LDCs (Toronto Hydro, Hydro Ottawa, Horizon, etc.)	• 78% Satisfied
		• 22% Dissatisfied and Neutral
			• 74% Satisfied
			• 26% Dissatisfied and Neutral
				• 78% Satisfied
				• 22% Dissatisfied and Neutral
					• **Customer Relations (55% - 40% - 40%)**
					  • Communications (26% - 20% - 20%)
					  • Responsiveness (29% - 16% -18%)
					  • Build relationship (8% - 6% - 6%)
					• **Planning (22% - 16% - 20%)**
					  • Outage Planning/Notification (8% - 8% - 10%)
					  • Infrastructure/upgrade (2% - 2% - 4%)
					  • Planning for work (6% - 6% - 4%)
					• **Product (12% - 18% - 18%)**
					  • Reliability/line maintenance/power quality (12% - 18% - 18%)
					• **Cost/Bills (4% - 10% -14%)**
					  • Cost (4% - 2% - 6%)
					  • Billing/invoicing (6% - 8% - 8%)

	Transmission connected load customers (Ford, GM, Lafarge, etc.)	• 80% Satisfied
		• 20% Dissatisfied and Neutral
			• 76% Satisfied
			• 24% Dissatisfied and Neutral
				• 97% Satisfied
				• 3% Dissatisfied and Neutral
					• **Product (34% - 36% - 32%)**
					  • Reliability/line maintenance/power quality (34% - 36% - 32%)
					• **Cost/Bills (10% - 22% - 24%)**
					  • Cost (10% - 17% - 21%)
					  • Billing/invoicing (0% - 6% - 3%)
					• **Customer Relations (37% - 33% - 15%)**
					  • Communications (15% - 19% - 9%)
					  • Build relationship (2% - 3% - 6%)
					• **Planning (10% - 17% - 9%)**
					  • Outage Planning/Notification (5% - 8% - 6%)

	Transmission connected generators (OPG, Bruce, NUGS, FIT, etc.)	• 89% Satisfied
		• 11% Dissatisfied and Neutral
			• 84% Satisfied
			• 16% Dissatisfied and Neutral
				• 81% Satisfied
				• 19% Dissatisfied and Neutral
					• **Customer Relations (24% - 32% - 22%)**
					  • Communications (21% - 23% - 13%)
					  • Build relationship (3% - 7% - 9%)
					  • Responsiveness (6% - 3% - 3%)
					• **Planning (35% - 39% - 44%)**
					  • Outage Planning/Notification (32% - 16% - 31%)
					  • Infrastructure/upgrade (0% - 7% - 6%)
					  • Planning for work (9% - 16% - 9%)
					• **Product (9% - 16% - 6%)**
					  • Reliability/line maintenance/power quality (9% - 16% - 6%)
					• **Cost/Bills (3% - 10% - 9%)**
					  • Billing/invoicing (0% - 3% - 6%)
					  • Cost (3% - 7% - 3%)

2013/14/15 data provided by Customer Experience

Customer - Tx Performance / Outliers

	Customer Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0-15MW		>15-40MW		>40-80MW		>80MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/year)	4.1	9.0	1.1	3.5	0.5	1.5	0.3	1.0
DP Interruption Duration (min/year)	89	360	22	140	11	55	5	25

Customer – Top Level Dx Satisfaction

hydro one

Attribute	Who they are?	How do they feel? (2013)	How do they feel? (2014)	How do they feel? (2015)	Main Issue to address in 2015 (trend 2013 - 2014 - 2015)
Large and Mid Customers	Large distribution accounts	• 80% Satisfied • 20% Dissatisfied and Neutral	• 73% Satisfied • 27% Dissatisfied and Neutral	• 78% Satisfied • 22% Dissatisfied and Neutral	• Reliability/line maintenance/restoration time (21% - 27% - 33%) • Cost/cost effectiveness (30% - 36% - 22%) • Power quality (9% - 10% - 13%) • Billing (4% - 10% - 9%) • Information (4% - 15% - 7%) • Info on Energy Conservation Programs (0% - 0% - 7%) • Responsiveness (2% - 3% - 6%)
	Commercial Customers	• 72% Satisfied • 28% Dissatisfied and Neutral	• 74% Satisfied • 26% Dissatisfied and Neutral	• 76% Satisfied • 24% Dissatisfied and Neutral	• Costs/rates (28% - 24% - 32%) • Reliability/power outage (21% - 20% - 19%) • Power quality (21% - 16% - 14%) • Other bill mentions (3% - 13% - 8%) • Outage communication (1% - 9% - 7%) • Better customer service (2% - 2% - 5%)

Residential and Small Business Customers	Distribution connected end-use customers	• 80% Satisfied
		• 20% Dissatisfied and Neutral
			• 67% Satisfied
			• 33% Dissatisfied and Neutral
				• 70% Satisfied
				• 30% Dissatisfied and Neutral
					• **Rates/Price (56% - 55% - 61%)**
					  • High rates (36% - 37% - 49%)
					  • Distribution/delivery charge (17% - 16% - 16%)
					• **Billing/payment (13% - 29% - 25%)**
					  • Billing errors (4% - 6% - 22%)
					• **Reliability/outage handling (25% - 16% - 20%)**
					  • Power Reliability/number of outages (19% - 15% - 15%)
					  • Power quality/brown outs/surges (3% - 0% - 6%)
					• **Operations/meters/forestry (17% - 24% - 16%)**
					  • Smart meter (2% - 6% - 5%)
					• **Market Structure (15% - 11% - 13%)**
					  • Debt retirement charge (13% - 10% - 11%)
					• **Customer service/concern/empathy (11% - 13% - 11%)**
					  • Poor customer service (3% - 5% - 5%)
					• **Management (3% - 6% - 6%)**

2013/14/15 data provided by Customer Experience

Customer – Service Quality Indicators

Service Quality Indicator	Benchmark	Reference
Connection of New Services (<750 volts)	5 days; 90% of the time	DSC – 7.2
Connection of New Services (>750 volts)	10 days; 90% of the time	DSC – 7.2
Appointment Scheduling	5 days; 90% of the time	DSC – 7.3
Appointment Met	4 hour window; 90% of the time	DSC – 7.4
Rescheduling a Missed Appointment	Reschedule before or within one business day; 100% of the time	DSC – 7.5
Telephone Accessibility	30 second accessibility; 65% of the time	DSC – 7.6
Telephone Call Abandon Rate	$\leq$ 10%	DSC – 7.7
Written Response to Enquiries	Sent within 10 business days; 80% of the time	DSC – 7.8
Emergency Response	Rural Response: 120 minutes; 80% of the time Urban Response: 60 minutes; 80% of the time	DSC – 7.9
Reconnection Standards (non-payment)	Within 2 days of full payment or payment agreement; 85% of the time	DSC – 7.10
Billing Accuracy	98% of the time	DSC – 7.11

Reliability:
Key Considerations

Considerations

- How will this decision impact system reliability?
- Will there be forced outages?
- Unsupplied energy?
- How many customers will be impacted?
- What type of customers are they?
- How large are the customers?

Strategic Objective:
Building and maintaining reliable, affordable transmission and distribution systems.
Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance.

Our distribution strategy is focused on continuing to meet the challenge of providing reliable, affordable service to our customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.

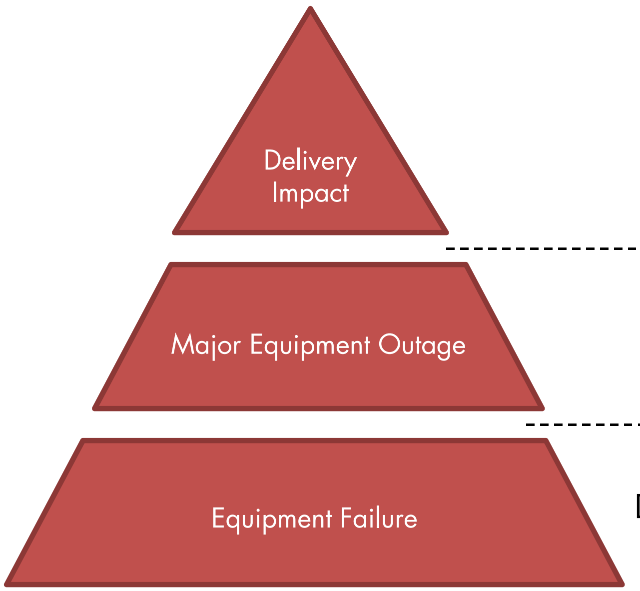
Reliability: Scorecard Calculation

Tx Duration of Customer Unplanned Interruptions = $$\frac{\sum_{i=1}^{N}(Dmci)}{Nmc}$$

- *Dmc$_i$* is the total effective interruption duration of unplanned, sustained interruptions to multi-circuit supplied Delivery Point *i* over the reporting period.
- *Nmc* is the total number of multi-circuit supplied Delivery Points in service during the reporting period

Dx Duration of Customer Interruptions = $$\frac{\text{Total Customer Hours of Interruptions (excluding Force Majeure \& Loss of Supply)}}{\text{Total Average Number of Customer Served during the year}}$$

Reliability Considerations



Corporate Reliability Measures

Equipment Availability/Reliability

Defective Equipment Component Mis-operations

Aged and deteriorated equipment may not directly impact system/customer reliability.

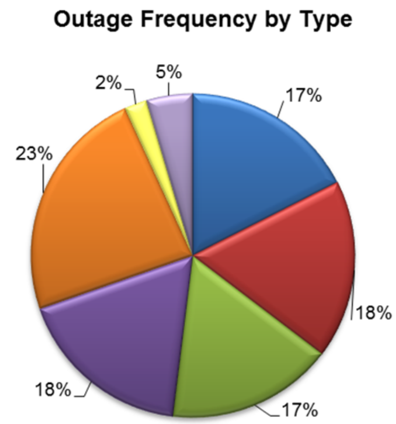
Leading-lagging relationship between equipment condition, major equipment performance, and system or delivery performance.

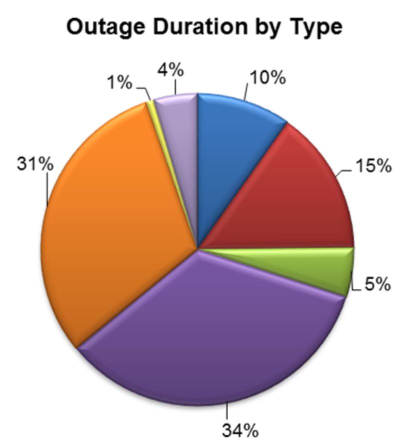
Reliability – Dx - 2014

Hydro One Networks Inc.

Customer Interruptions		
0 - Unknown/Other	803,984	18%
1 - Scheduled Outage	815,931	18%
2 - Loss of Supply	760,897	17%
3 - Tree Contacts	811,549	18%
4 - Lightning	-	0%
5 - Defective Equipment	1,074,122	23%
6 - Adverse Weather	-	0%
7 - Adverse Environment	1,166	0%
8 - Human Element	102,572	2%
9 - Foreign Interference	211,077	5%
Total	**4,581,298**	100%

Customer-hours of Interruptions		
0 - Unknown/Other	1,252,041	10%
1 - Scheduled Outage	1,929,728	15%
2 - Loss of Supply	648,695	5%
3 - Tree Contacts	4,380,103	34%
4 - Lightning	-	0%
5 - Defective Equipment	3,919,428	31%
6 - Adverse Weather	-	0%
7 - Adverse Environment	5,032	0%
8 - Human Element	98,109	1%
9 - Foreign Interference	577,809	5%
Total	**12,810,945**	100%





2014 Data: As presented in OEB 2014 Yearbook of Distributors (July 31, 2015)
2002-12 Data: Per OEB consultation of Reliability Standards ("PEG Report and Analysis")

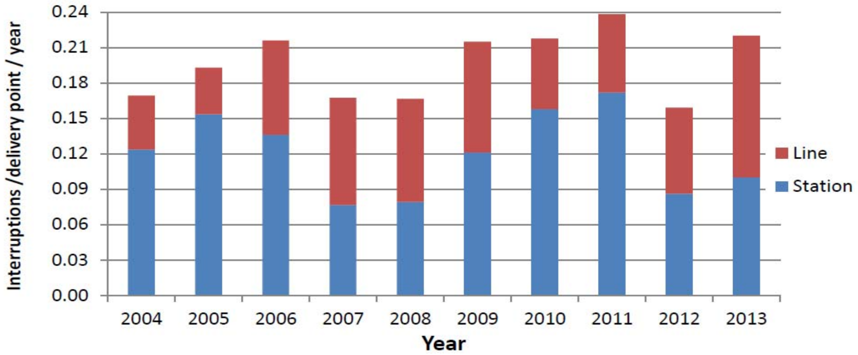
Impact Attribute/Description:
Distribution Reliability - system outages in one year - Duration of Dx Outages Measured in Interruption hours

SAIFI:
2002 - 12: 3.90 interruptions per customer per year (average)
2008 - 12: 3.97
2010 - 12: 3.83

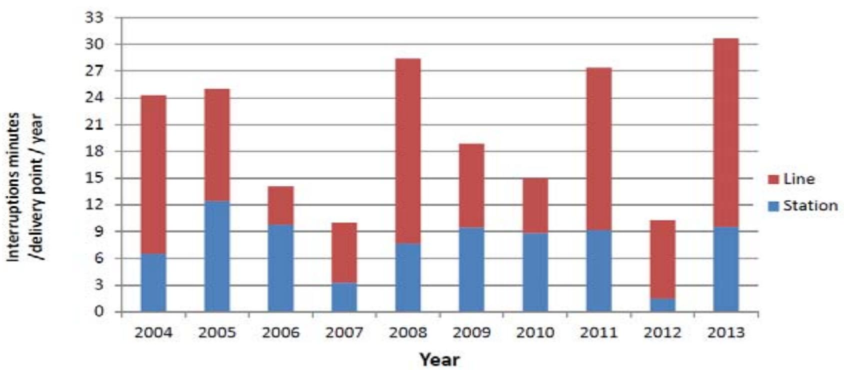
SAIDI:
2002 - 12: 14.82 hours of interruptions per customer per year (average)
2008 - 12: 14.86
2010 - 12: 14.25

Controllable Factors	Uncontrollable Factors
2014 SAIDI: 81% 2014 SAIFI: 61%	2014 SAIDI: 19% 2014 SAIFI: 39%
• Defective Equipment • Scheduled Outages • Tree Contacts • Human Element	• Foreign Interference • Loss of Supply • Adverse Environment • Adverse Weather • Lightning • Unknown

Reliability - Tx



Equipment Failures Contributing to Frequency of Interruptions; All Delivery Points (Single & Multi-circuit Supplied)



Equipment Failures Contributing to Duration of Interruptions; All Delivery Points (Single & Multi-circuit Supplied)

Impact Attribute/Description:
Transmission Reliability - acute events-Transmission unsupplied energy

As a consequence of the redundancy often found in the transmission system, it's not unusual for an equipment defect or failure to have only a momentary impact on the power system, or in some cases no noticeable impact to end-use customers at all.

Environment:
Key Considerations

- Environmental Performance: Adverse environmental impact or emissions
  - Spills/releases
  - Presence of PCBs
  - Reduction to carbon footprint/greenhouse gas

- Considerations
  - Size/Effectiveness of Spill Containment
  - Emission control Initiatives
  - Location; proximity to water supply (Municipal/Regional supply, local (private well) supply, etc.)

Strategic Objective:
Protecting and sustaining the environment for future generations.
Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.

Safety:
Key Considerations

Employee Health & Safety Policy Commitment
- Implement and sustain a world class health and safety management system.
- Identify and evaluate health and safety risks to ensure that hazards are eliminated or controlled.
- Establish an effective process for preventing all injuries and work related illnesses.
- Build a culture that requires positive visible leadership with clear accountability.
- Provide everyone with timely and effective training.
- Investigate all incidents in order to prevent a recurrence.
- Stop unsafe work.
- Establish measurable objectives to monitor progress through regular audits and performance reporting.
- Obtain input from employees and their representatives on health and safety issues.
- Promote a healthy workplace.
- Meet or exceed all legal requirements wherever we operate.

Public Safety Policy Commitment
- Comply with all applicable legal requirements and follow good utility work practices to protect the public.
- Use a risk-based approach to incorporate public safety considerations into business practices and decisions.
- Promote public awareness of safety issues related to our electrical facilities.
- Encourage and support stakeholder initiatives that address public safety issues.
- Support community safety initiatives through our Community Citizenship Program.

Strategic Objective:
Creating an injury-free workplace and maintaining public safety.
Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.

Safety: Scorecard Calculation

$$\textbf{Recordable Rate} = \frac{\text{Number of Recordable Injury/Illness YTD}}{\text{Total Number of Hours Worked YTD}} \times 200{,}000$$

Data Source

- Data for this metric comes from the Incident & Claims Management (ICM) System.

Productivity and Cost Effectiveness: Key Considerations

Considerations

- High expectations from all stakeholders (Regulator, Board of Directors, Senior Management, etc.) that productivity will be improved

- Continued perception of inefficiency and poor cost management/productivity could lead to significant challenges to our growth aspirations and even our existing business model.

Strategic Objective:
Achieving productivity improvements and cost-effectiveness.
To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our Shareholder.

Productivity and Cost Effectiveness: Scorecard Calculation

Transmission Unit Cost	=	$\frac{\text{Tx Actual OM\&A}}{\text{Tx Actual Gross Fixed Assets}}$
Distribution Unit Cost	=	$\frac{\text{Dx Actual OM\&A}}{\text{Dx Actual Gross Fixed Assets}}$

Data Source

- Data for this metric comes from the monthly Program & Project Status Report, reported monthly by Finance.

Productivity and Cost Effectiveness

Attribute	Baseline Reference		Considerations
Work Program Shortfall (per HOI plan and commitments):			
1. In-Service Capital or Capital Work Program Shortfall (Tx)	ISA - OEB: 2015: $821M 2016: $673M	CapEx – OEB: 2015: $899M 2016: $866M	Included in Rate Filing? 1% ISA: ~$6-8M 1% CapEx: ~9M
2. In-Service Capital or Capital Work Program Shortfall (Dx)	ISA - OEB: 2015: $657M 2016: $623M 2017: $696M	CapEx – OEB: 2015: $649M 2016: $655M 2017: $661M	Included in Rate Filing? 1% ISA: ~$6-7M 1% CapEx: ~$6-7M
3. Work Program OM&A Shortfall (Tx)	OEB: 2015: $339M 2016: $346M		Included in Rate Filing? 1% OM&A: ~$3 – 3.5M
4. Work Program OM&A Shortfall (Dx)	OEB: 2015: $553M 2016: $555M 2017: $559M		Included in Rate Filing? 1% OM&A: ~$5.5M
Failure meet Unit Cost targets per plan			
1. Tx OMA/Gross Fixed Assets	2015: $432M/$15.6B [2.8%]		1% increase: ~$4M OM&A increase
2. Dx OMA/Gross Fixed Assets	2015: $566M/$10.2B [5.5%]		1% increase: ~$5-6M OM&A increase

AIP Tool Training – Table of Contents

Document Change Log

Date (mm/dd/yyyy)	Description	Made by:
01/20/2016	Initial published version.	Michael Fraites

1 COURSE OBJECTIVES

By the end of this course, the expectation is that all participants will:

- Understand AIP's role in the Investment Planning Process
- Understand how to create and update investment attributes, etc. in AIP and how to send the investment for approval through workflow
- Understand data requirements and how the optimization processes may use that data to change inputs
- Be able to navigate and search commonly used screens/modules and reports
- Be able to run specific reports
- Understand the critical inputs

2 OVERVIEW OF C55

2.1 WHAT IS AIP?

AIP is Software tool developed by CopperLeaf Technologies and implemented at Hydro One in 2013.

- Provides an enterprise tool for entering investments and alternatives, evaluating risk and performing scenario analysis across all investment types (Projects and Programs)
- Goal of AIP tool is to utilize investment inputs in conjunction with the optimization module to select the best blend of investments within a given planning period (e.g. 2017 – 2022) that delivers the most value to Hydro One while adhering to the corporate financial constraints
- **Well-developed risk assessments are critical in order for AIP to do its job and pick the “right” investments**

2.2 WHAT’S NEW IN VERSION 8.3

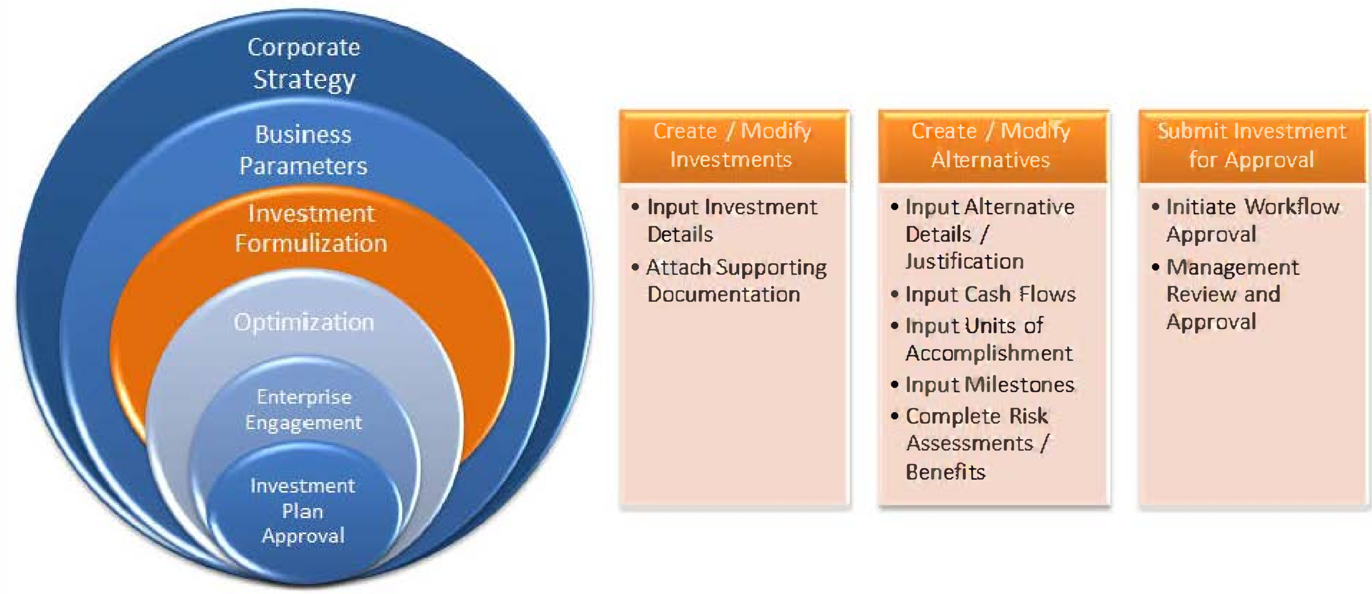
- Single Sign On – no more usernames and passwords!
- Investments are automatically “submitted” upon workflow initiation
- Ability to specify asset replacements and associated costs in the year they occur
- Ability to articulate Baseline Risk justification as part of Investment Details
- Project milestones shift (Estimates Dates, BCS Approval Date, In-Service Date) in unison with project start date shifts
- Ability to control earliest and latest start dates for shift-able projects
- Ability to specify Start Date Offsets and Alternative dependencies
- Option to shift alternative start dates **without** shifting cash flows or milestones
- Accomplishment File – new look and feel + more information

2.3 AIP CONCEPTS AND DEFINITIONS

http://hydronet.hydroone.com/LoB/Operations/PO/TAM/AIP/Reference Materials/AIP Concepts and Definitions.docx

2.4 YOUR ROLE IN AIP

The Investment Owner's role is to provide inputs that go into the Investment Formulization process. Key activities that the Investment Owner must complete for **each** investment that is input into AIP and put forth for approval are the following:



2.5 HOW TO LOGIN

In order to login to AIP, please click on the appropriate link below:

AIP Production

https://aipprod.corp.hydroone.com/AIPPROD/CopperLeaf5

AIP Development (use this link for training/testing only)

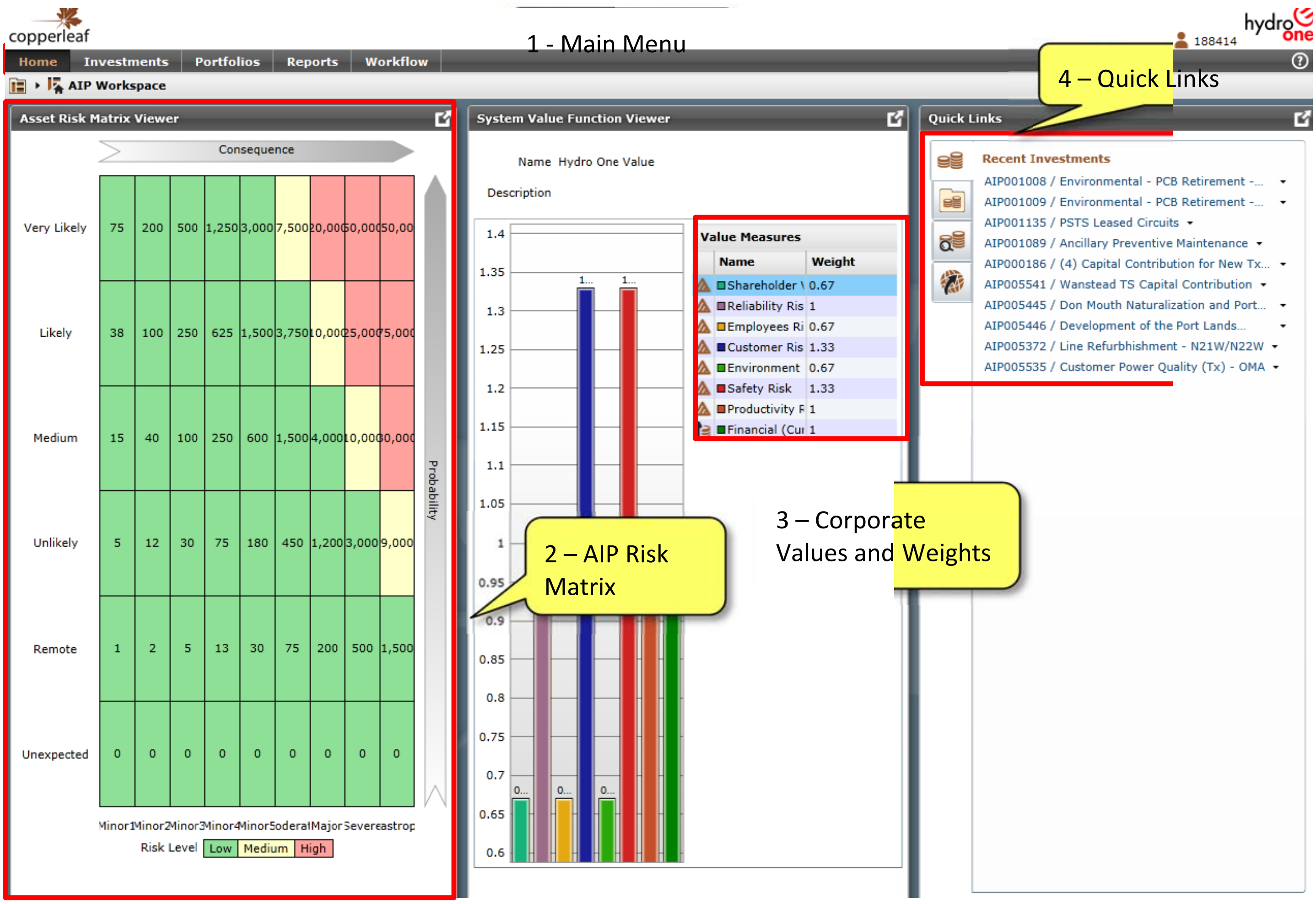
http://aipdev.corp.hydroone.com/AIPDEV/CopperLeaf5/

Note: If you are prompted to enter your username/password, you are using an old link, please refer to the links above and update any old bookmarks/favourites.

3 MODULE 1: AIP BASIC NAVIGATION

3.1 HOME PAGE

The default view when logging into AIP is shown below:



Area	Description
1 – Main Menu	Navigation Menu that is accessible throughout the entire application. Clicking on a menu item will accomplish following: **Home –** Brings you back to the homepage at any time **Investments –** Displays a list of all investments / allows you to search for investments **Portfolios** – Displays a list of all investment drivers in AIP (mimics the SAP-IM Hierarchy) **Reports –** Displays a list of reports that can be generated **Workflow** – Displays a list of all items assigned to you via Workflow
2 – AIP Risk Matrix	Shows the risk score associated with each Probability * Consequence

3 – Corporate Values and Weights	Displays a list of all corporate values and that can be accounted for when completing the risk mitigation section for an investment alternative along with the associated weighting that will be applied when computing an alternatives total value score.
4 – Quick Links	Displays link to recently opened Investments, Portfolios, Searches, and links to external web sites

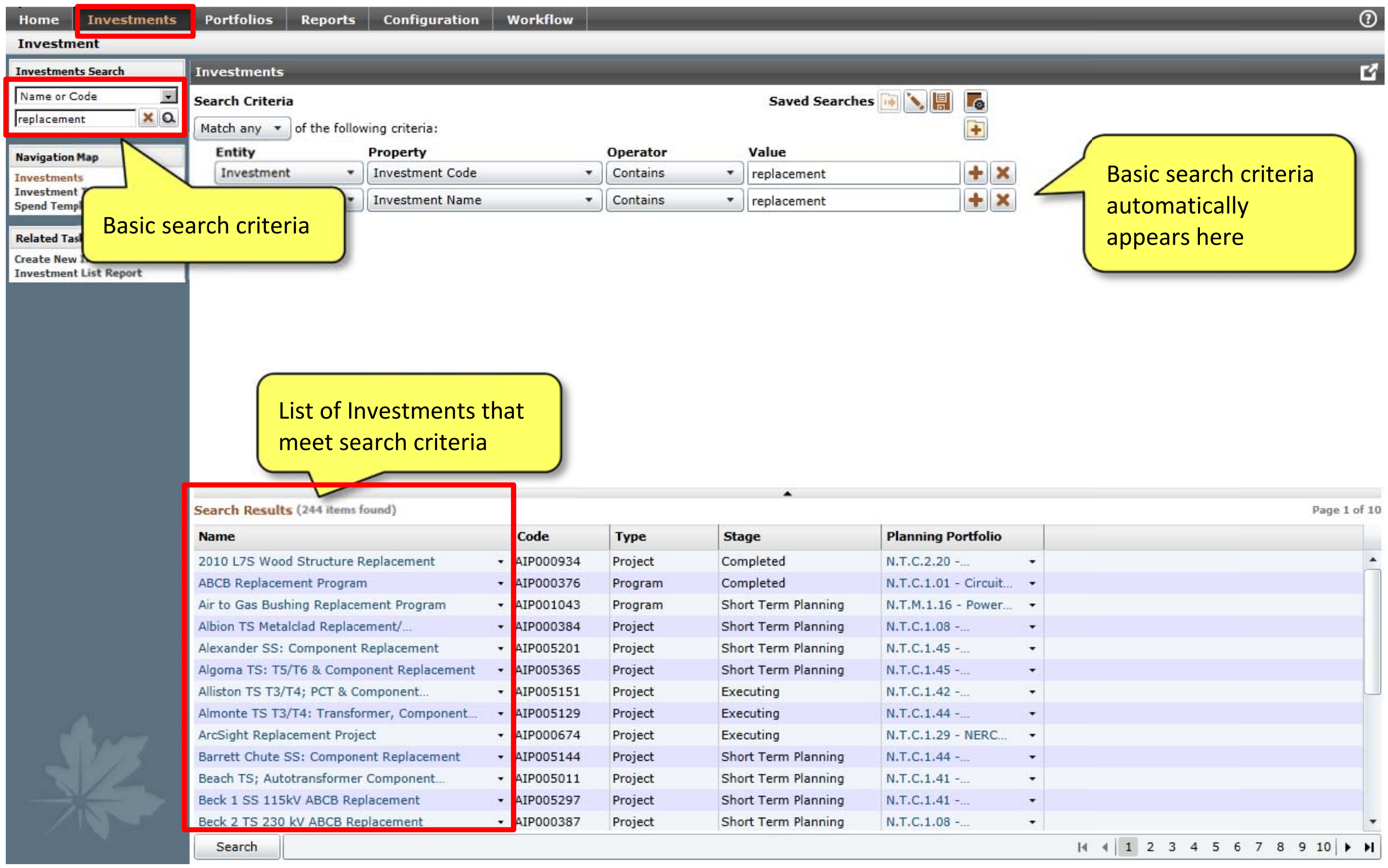
3.2 SEARCHING FOR AN INVESTMENT

AIP allows you to search for an investment using **Basic Search** (Investment Name or Code) or **Advanced Search** (multiple criteria).

3.2.1 BASIC SEARCH

Instructions

1. Click on <**Investments**> on the main menu
2. Enter any part of the Investment Name or Code under the "**Investment Search**" Menu and click  to Search
3. From the <**Search Results**> page, click on the name of the desired Investment to open the Investment Detail



3.2.2 ADVANCED SEARCH

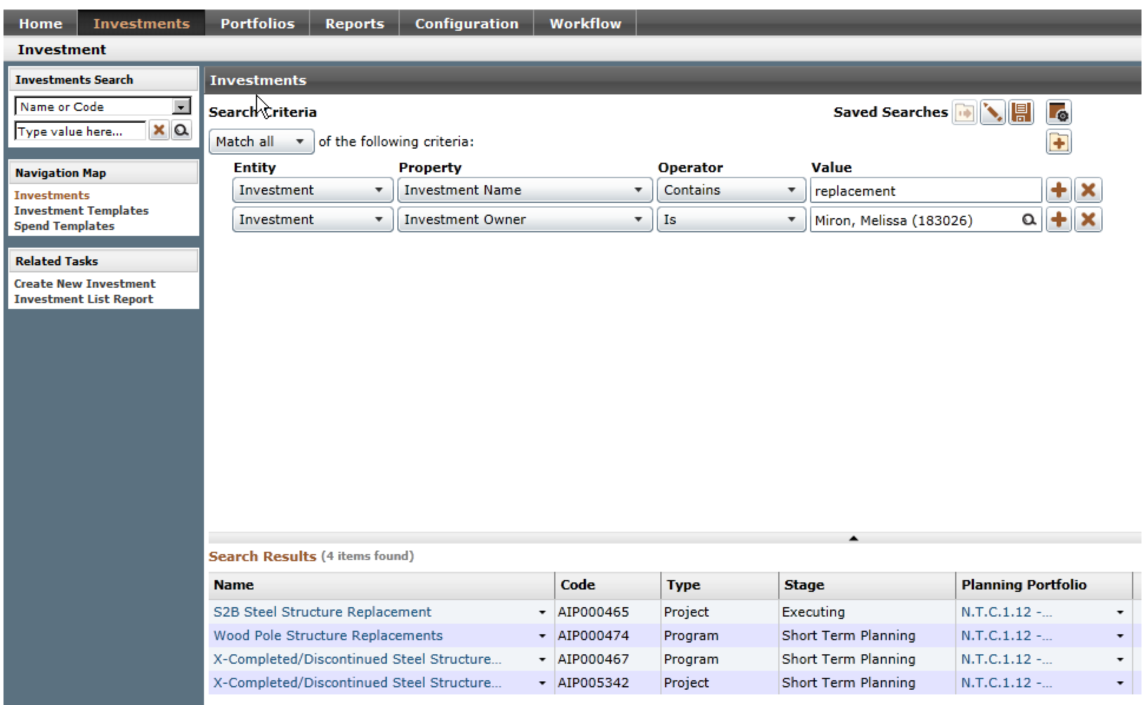
Advanced search allows users to search for an investment using any available investment attribute (e.g. Investment Owner, Planning Portfolio) or forecast attribute (e.g. AR Number).

Each search criteria consists of the following elements:

Entity - Choose from a selection of entities to be searched (e.g. Investment, Draft Forecast, etc.)
Property - The values available are dependent upon the Entity chosen above
Operator - A selection can be made from: Contains, is, is not, not contains, is null, is not null or is, or is child of. The Operator selections will depend on the Entity and Property chosen
Value - Depending on the Property chosen, the value may be a pick list or free text

Instructions

1. Click on **<Investments>** on the main menu
2. Select either Match all or Match any to broaden or restrict the search scope (default is match all)
3. Click on the icon to add a search criteria line(s)
4. Using the dropdowns on the search criteria line(s), select the require **Entity**, **Property**, **Operator** and enter the applicable search **Value**
5. Click Search to Search



Commonly Used Search Criteria

Entity	Property	Operator	Value
Investment	Investment Owner	Is	*Investment Owner Name*
Investment	Planning Portfolio	Is	*Driver*
Investment	Stage	Is	*Investment Stage*
Draft Forecast	Appropriation Request	Is	*AR Number*

3.2.3 SAVING A SEARCH

After creating a new search, you may choose to save it for faster recall in the future.

Instructions

1. Click on the icon to Save the Advanced Search criteria
2. Give the Search a Name and Description (optional) and select whether the Search is private (only accessible to you) or public (accessible to all AIP users).
3. Click on the icon to modify an existing saved Advanced Search's Name, Description, or Public/Private flag.

Tip: A common Saved Searched is based on Investment Owner and/or Planning Portfolio(s).

3.2.4 LOAD AN EXISTING SAVED SEARCH

Instructions

1. Click on **<Investments>** on the main menu
2. Press the Load button for a list of saved searches
3. Click Search to Search

-OR-

4. From the **<Home>** page click on the icon under "Quick Links" and select your Saved Search

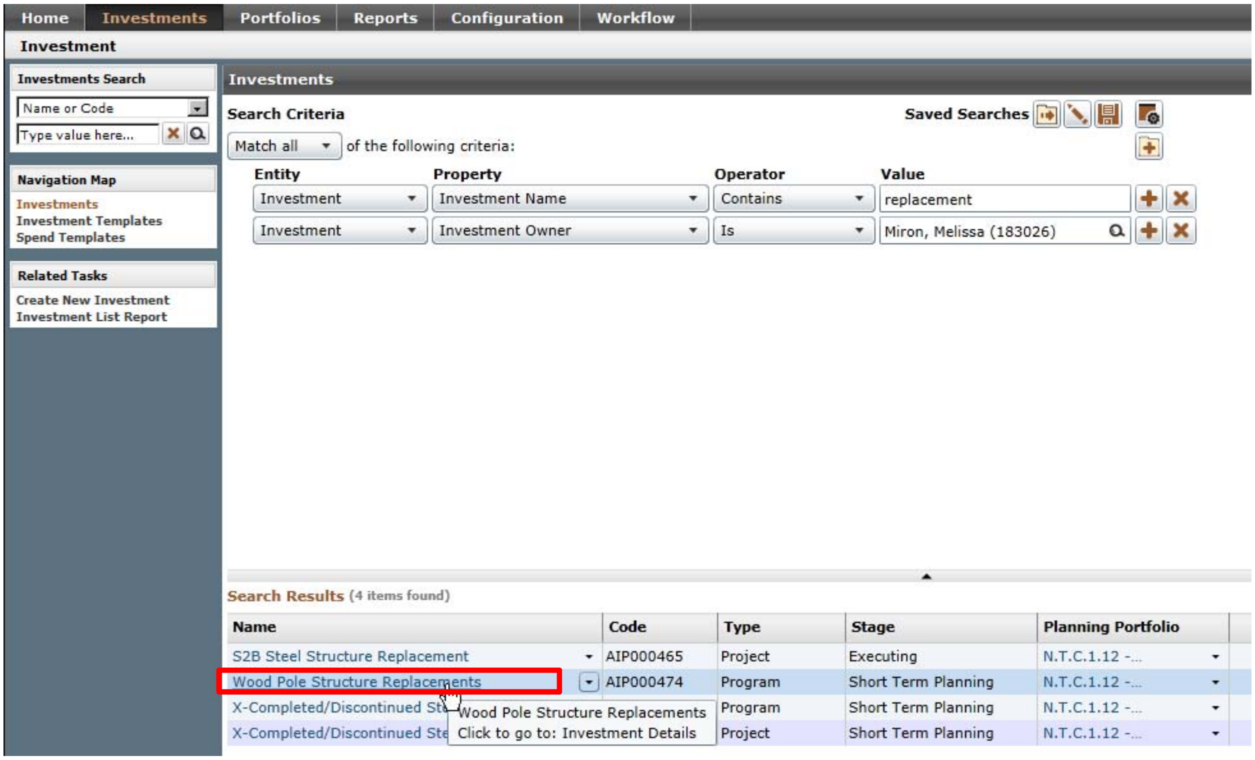
3.3 VIEWING AN INVESTMENT

Viewing an investment allows you to review all information that is input into an investment by an Investment Owner.

3.3.1 LAUNCH AN INVESTMENT

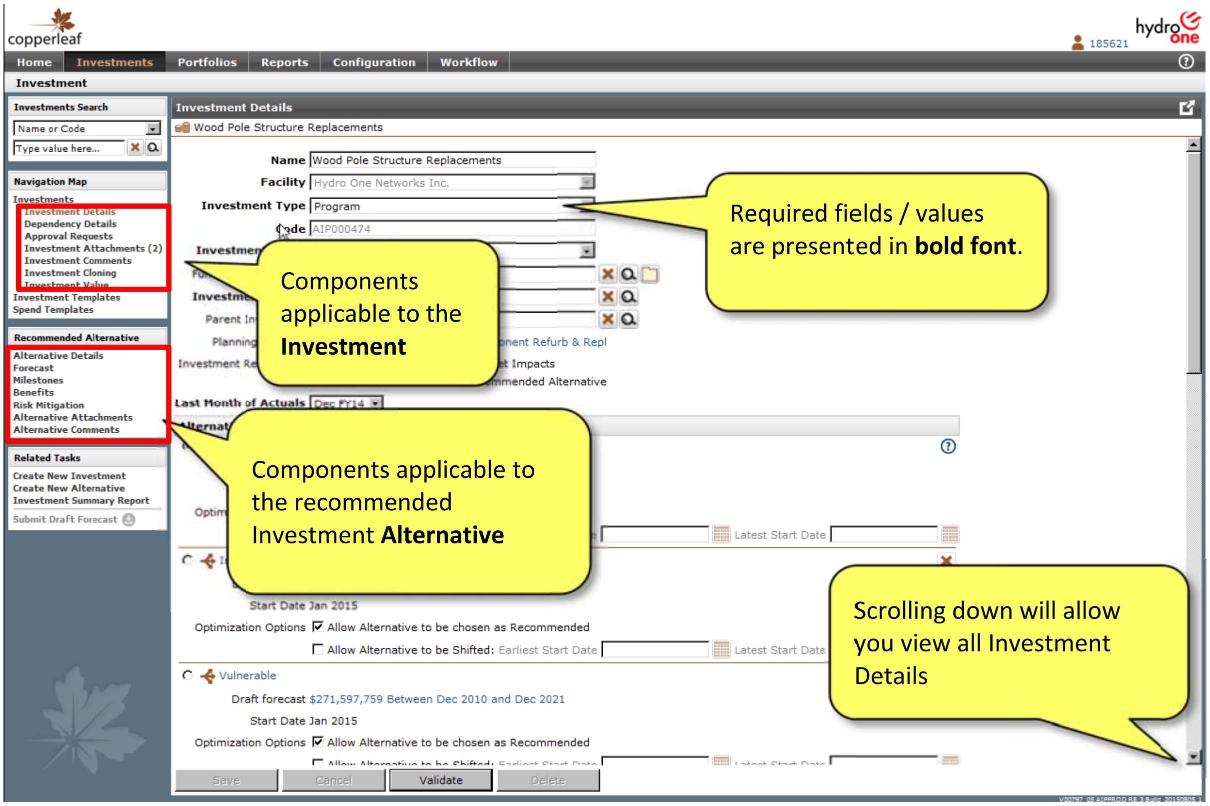
Instructions

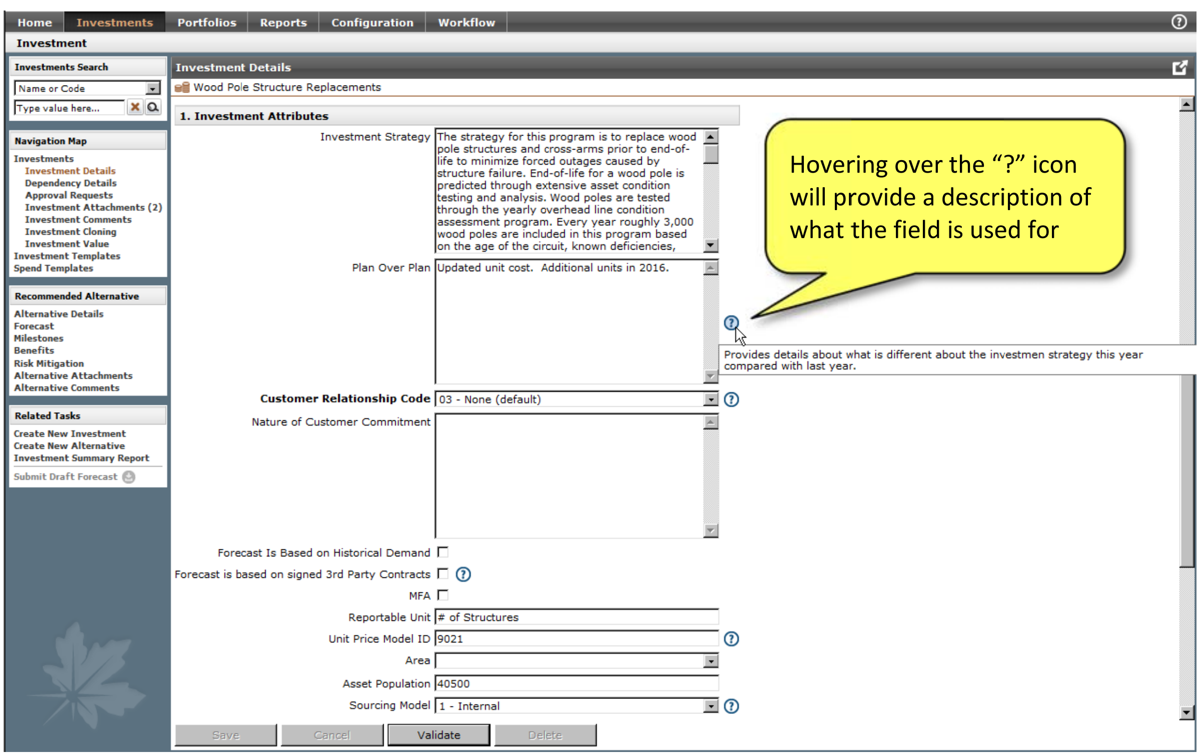
1. From the <**Search Results**> page, click on the name of the desired Investment to open the Investment Details



3.3.2 VIEW INVESTMENT DETAILS

Once an Investment is launched, all components of the investment will be accessible (e.g. Investment Attributes, Attachments, Alternatives, Milestones, Risk Mitigation, etc.)



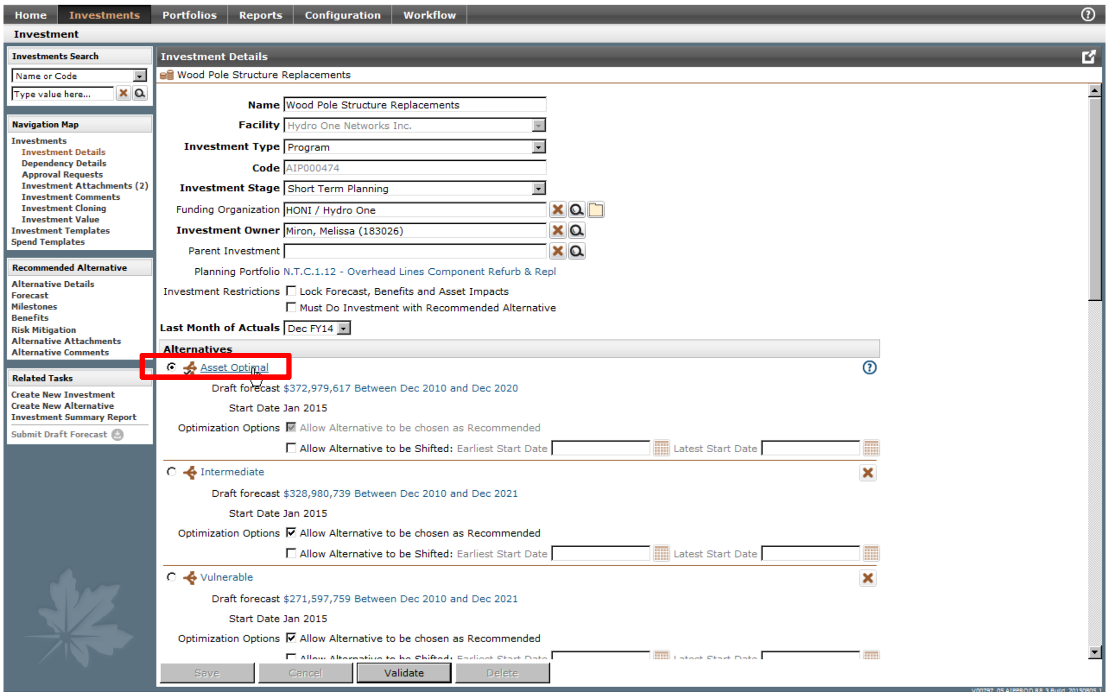


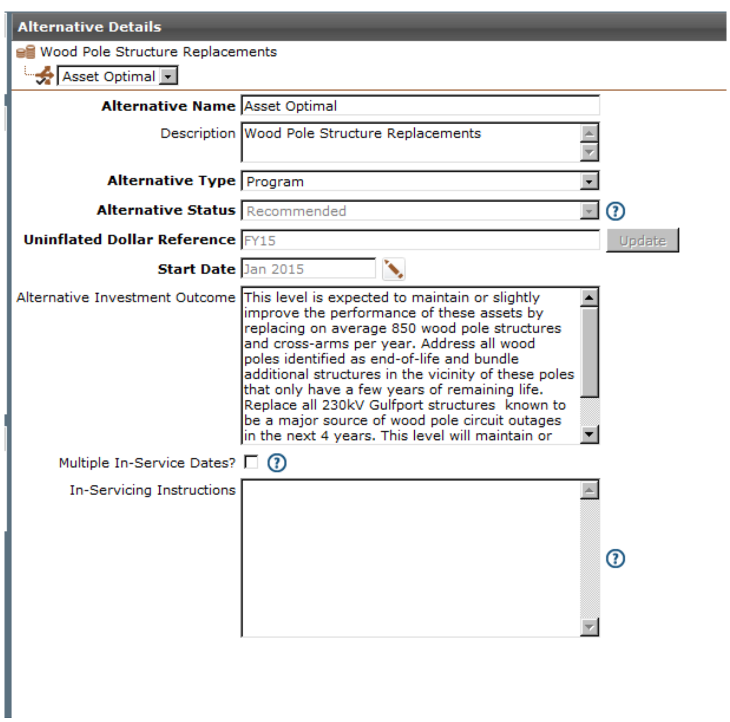
3.4 VIEWING AN ALTERNATIVE

3.4.1 VIEW ALTERNATIVE DETAILS

Instructions

1. From the <**hvestment Details**> page of an Investment, click on the name of the desired alternative to open the Alternative Details. Note that, the fields available for population may differ depending on the Alternative Type (Project, Program, Demand Funnel).

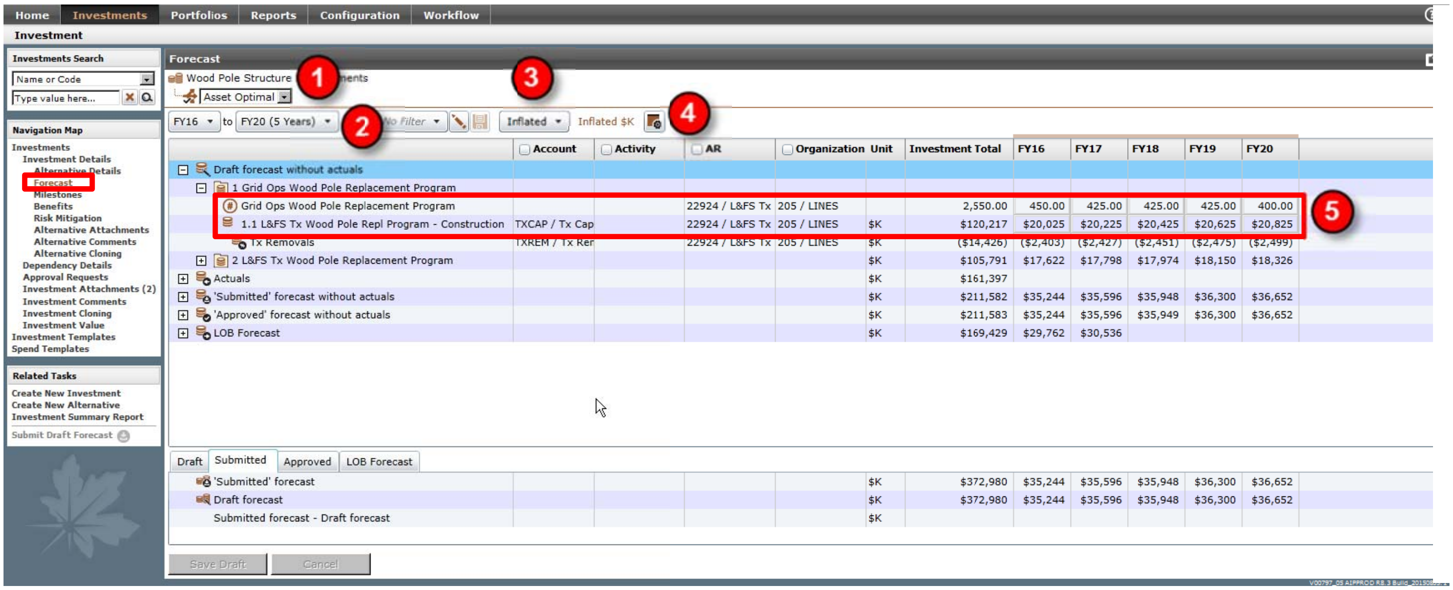




3.4.2 VIEW ALTERNATIVE FORECASTS

Instructions

1. From the <**Investment Details**> page of an Investment, click on “Forecast” under the Navigation Map



The following options are available in the bar at the top of the Forecast UI:

1	**Alternative selection control:** You can easily switch between Alternatives using the **<Alternative>** dropdown at the top of the **{Forecast}** page. If there is only one Alternative, it will simply state the name of the Alternative.
2	The years to display on screen. **This should typically be set to the investment planning window.** Selecting a narrow time window (by default, 1 year) will let the {Forecast} columns display in monthly format.
3	Inflated vs. Uninflated dropdow: This changes the display of dollar values to be either inflated or uninflated. If entering Forecast values, be aware of whether they are inflated or uninflated, and ensure that this control is set as appropriate. Uninflated is only available for the Draft Scenario.
4	Options window. Allows you to specify view options such as the Dollar Scale for Forecast $’s
5	Represents the Forecast Accomplishments (e.g. # poles), associated with the spend line

4 LAUNCHING REPORTS

Various reports can be generated based on investment data in AIP. However, with the exception of Investment Summary Reports, all reports are generated and distributed by the AIP Team (e.g. Accomplishment File, Investment Value Report, etc.).

4.1 INVESTMENT SUMMARY REPORT

The Investment Summary Report is meant to provide an overview of the investment and all proposed alternatives. It contains the following information:

Investment Overview

- Driver, Planner, Strategy etc.

Alternative Spend Profile

- A comparison of alternatives by year
- Will include the latest approved plan, actuals and current year forecast for comparison

Investment Value

- Shows the total value score (not weighted) and Value / $ for each alternative
- Value Score is also broken down by corporate value

Comments and Attachments

- Shows any comments and attachments entered by the Planner to add context

Alternative Details for each Alternative

- Alternative Outcome, Milestones, Net and Gross Spend, Accomplishment Units

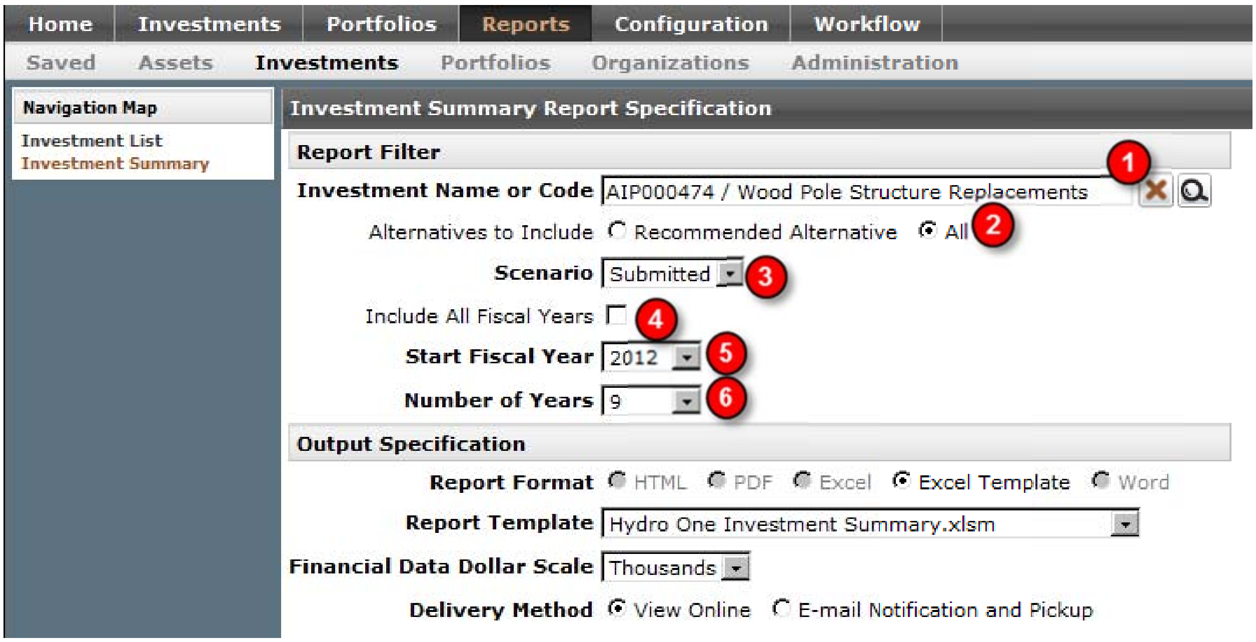
Alternative Risk Impact for each Alternative

- Output of Risk Assessment in full form/plotted on a graph (only up to four values with the highest baseline risks will appear in the report)
- Benefits

4.1.1 GENERATE AN INVESTMENT SUMMARY REPORT

Instructions

1. Click on **<Reports>** on the main menu
2. Click on **<Investments>** on the sub-menu
3. Click on "**Investment Summary**" under the navigation map
4. Fill out the available parameters (see table below for a full explanation**)**
5. Choose desired delivery method (E-mail Notification and Pickup is reco**m**mended)
6. Click "**Generate**"



1	Choose the investment by entering any part of the Investment Name or AIP Code, clicking the magnifying glass and selecting it.
2	Indicate if you want to include all alternatives, or just the recommended alternative.
3	Choose the scenario that you want to base the forecast information on. **This should typically be set to Submitted**.
4	**This should typically be unchecked**
5	For annual Programs select: 2014 For Projects, choose the first year of your project cash flows
6	For annual Programs select **9.** This will allow you to see **2014 and 2015 Actuals** + **2016 LOB Forecast** + **2017 – 2022 Plan** (choosing more than 9 years will result in a poorly formatted repo**r**t) For Projects, choose the Total Years in the upcoming Planning Peri**o**d

MODULE 2: CREATING INVESTMENTS

What are Investments?

Investments are holding entities to capture investment needs. Key concepts to keep in mind when creating investments are the following:

- Investment Owners are expected to search for investments and **only create a new investment (via cloning a template or an existing investment) if it's not found**
- Investments **cannot** be deleted – if an investment is not to be used, add "X - Completed/Discontinued " to the beginning of the Investment Name
- Some fields are mandatory (bolded on the screen)
- **Programs and Projects** will have different fields that must be populated.
- Use investment Templates, rather than creating new ones from scratch
- The following Templates are available:
  - Common Driver Capital/OMA Template (Program/Project)
  - Dx Capital/OMA Template (Program/Project)
  - TSD Project Template
  - Tx Capital/OMA Template (Program/Project/Projects with Forecast Accomplishments)

4.2 CREATE NEW INVESTMENT

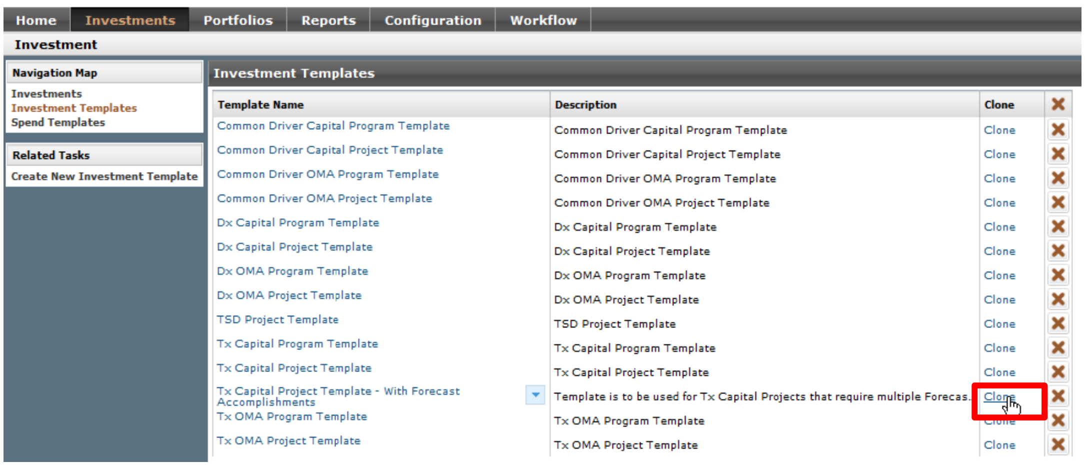
A new investment shall only be created if an existing investment does not already exist. Most of the time, an investment will already exist and can simply be edited. However, if a new investment is required, it must be created using an Investment Template or by Cloning and existing investment.

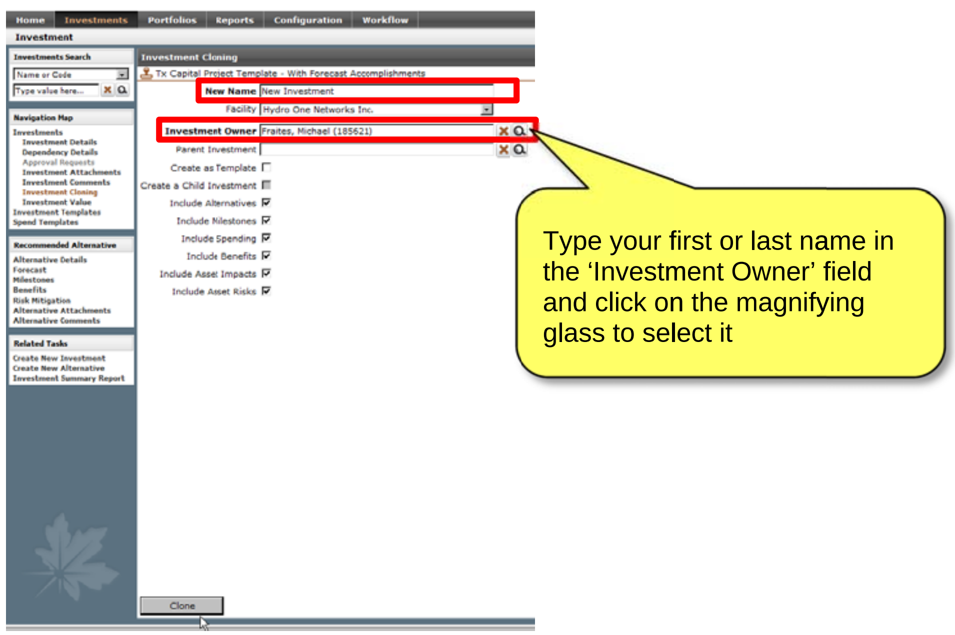
Tip: Check if an investment already exists using the search functionality outlined in the beginning of this document.

4.2.1 CREATE A NEW INVESTMENT FROM A TEMPLATE

Instructions

1. Click on **<Investments>** on the main menu
2. Click on **Investment Templates** in the Navigation Map
3. Browse the available Templates and click "**Clone**" based on the type of investment that is being created
4. Input the Investment Name as well as the Investment Owner and click **"Clone"**

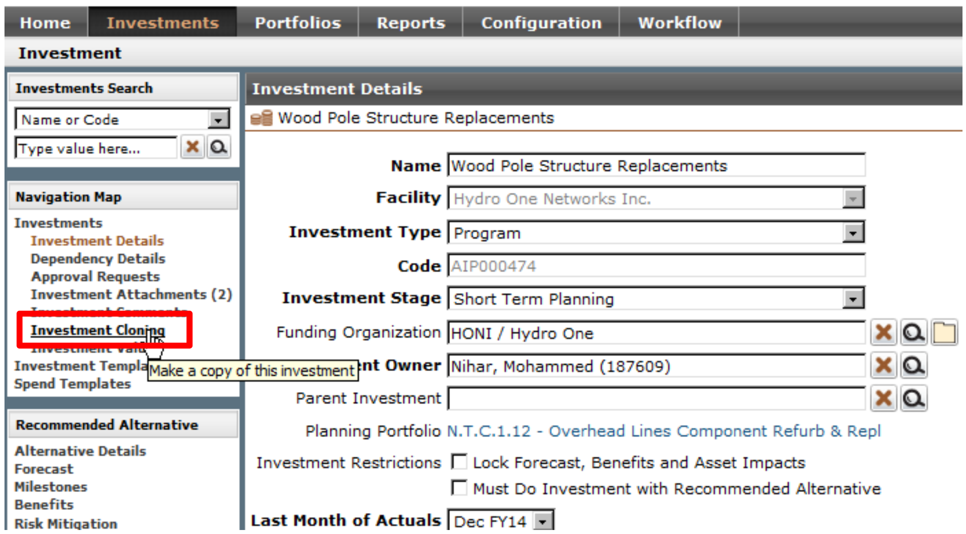


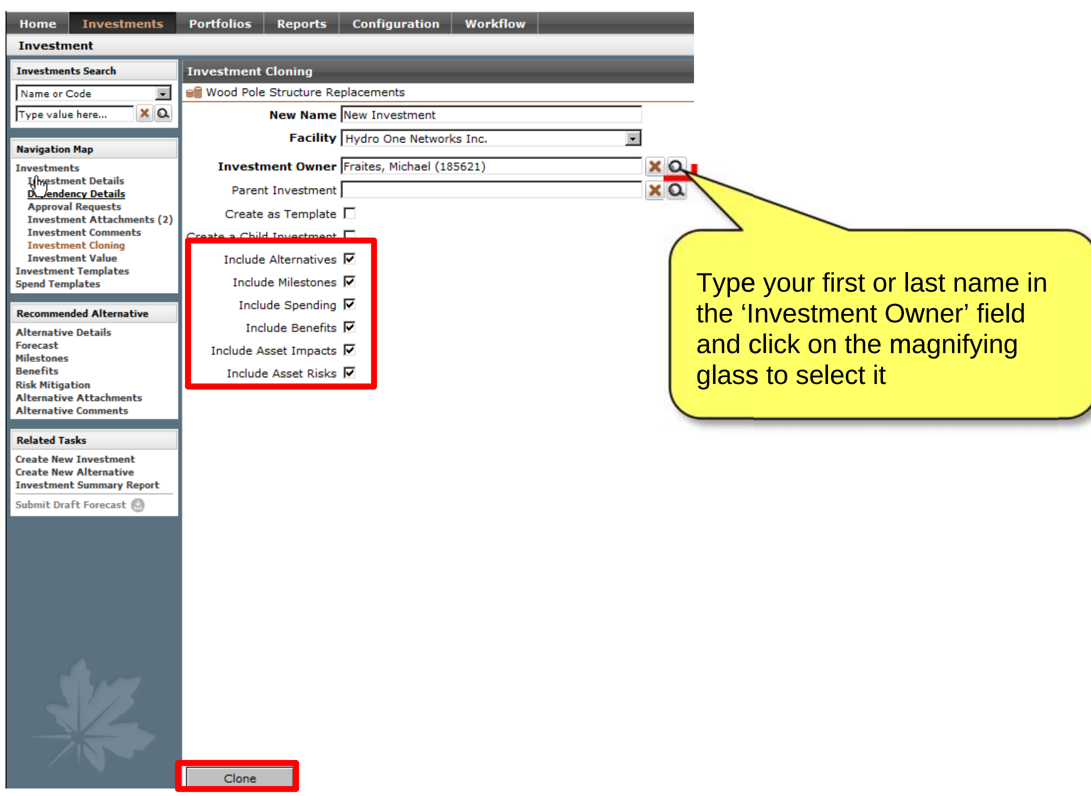


4.2.2 CREATE A NEW INVESTMENT FROM AN EXISTING INVESTMENT (INVESTMENT CLONING)

Instructions

1. Click on **<Investments>** on the main menu
2. Search for the investment you wish clone
3. Click on the Investment to view Investment Details
4. Once the investment is opened, click "**Investment Cloning**" on the left-hand menu
5. Input the Investment Name, Investment Owner and check off all aspects of the investment you wish to copy and click "Clone"





4.3 UPDATE INVESTMENT DETAILS

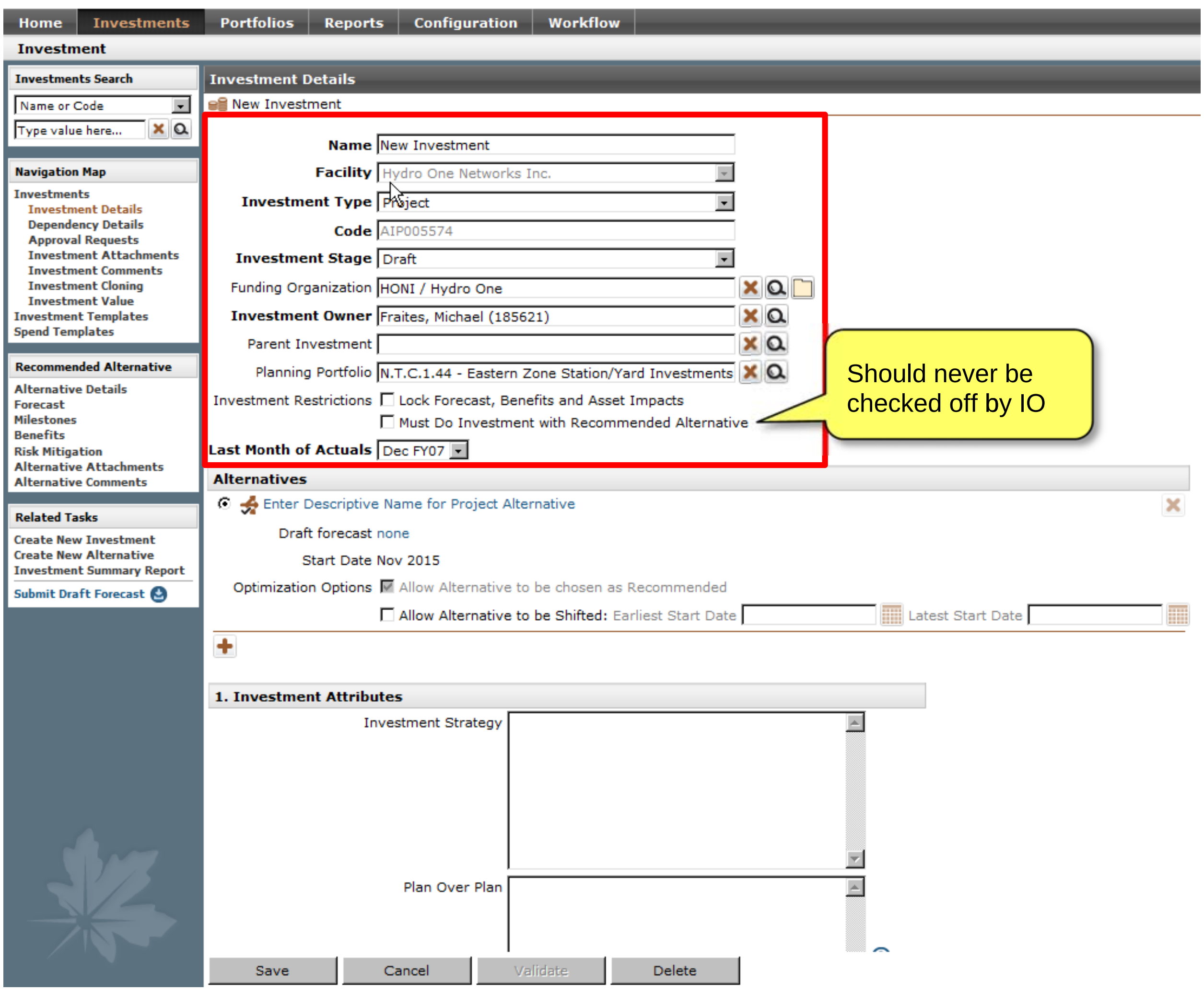
4.3.1 INPUT INVESTMENT HEADER INFORMATION

The investment header information contains the fundamental details of the investment.

Instructions

1. Enter the appropriate information based on the IO Accountabilities indicated below
2. Click “Save”.

Field	Accountability	Notes
Name	**IO**	
Facility	AIP Team	
Investment Type	**IO**	Investment type must be consistent in both AIP and SAP-IM.
Investment Stage	**IO**	IO’s should only set to the stage to Draft, Short Term Planning or Long Term Planning. All other stages are maintained by the AIP Team. Note that, only Short Term Planning investments can be routed for approval.
Funding Organization	AIP Team	
Investment Owner	**IO**	
Parent Investment	**IO** / AIP Team	Any changes to this field must be made in consultation with the AIP Team. This field is used for the purposes of managing investment dependencies
Planning Portfolio	**IO**	Planning Portfolio must be consistent in both AIP and SAP-IM. Any subsequent changes to this field must be through the AIP Team.
Investment Restrictions	AIP Team	
Last Month of Actuals	AIP Team	



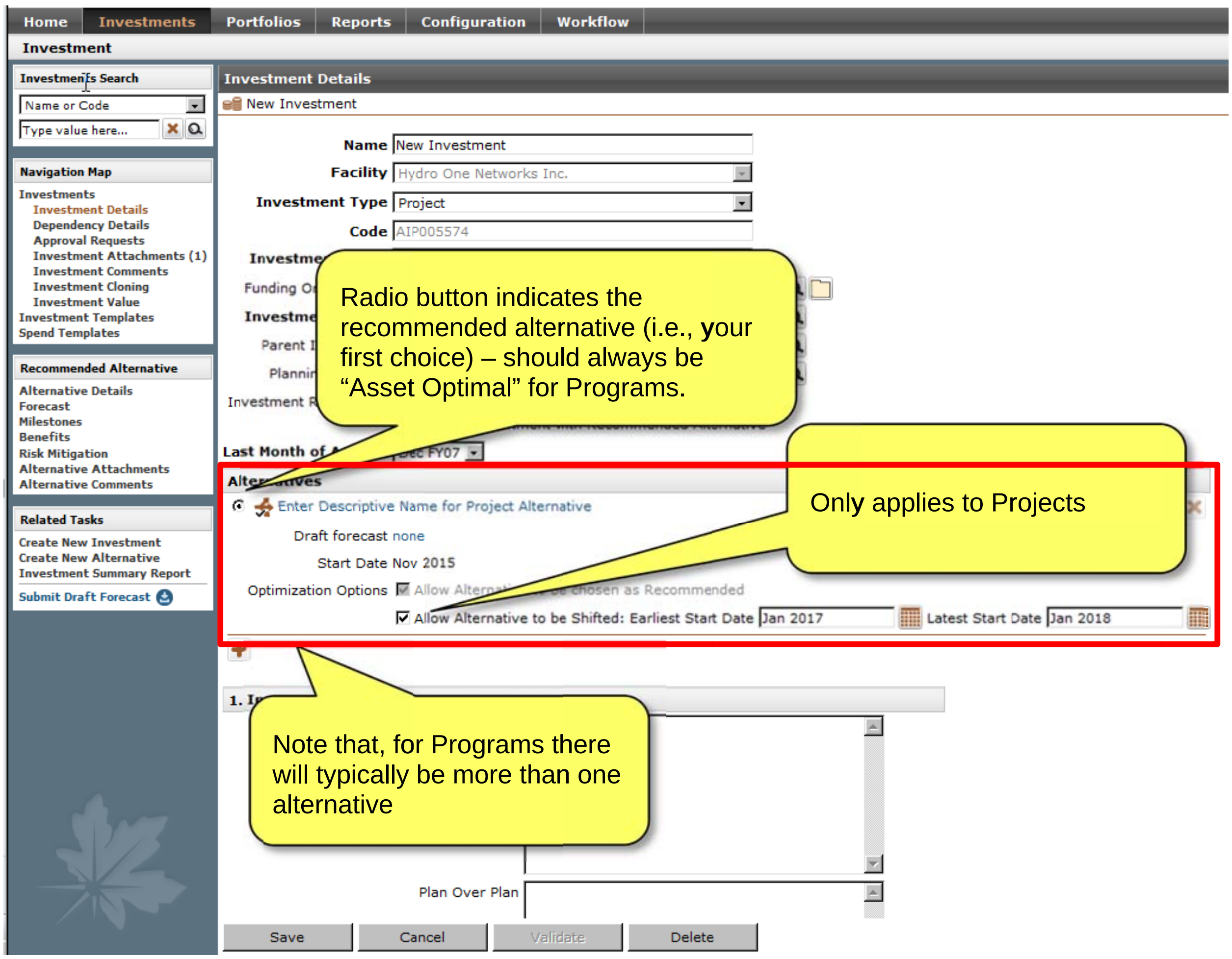
4.3.2 SPECIFY ALTERNATIVE OPTIMIZATION OPTIONS

The Alternatives section provides a summary of all the alternatives that are possible options to address the investment need. Note that, the only settings that can be modified in this area are the **Optimization options.** A full overview of how to create/edit alternatives details will be described later.

1. Indicate if the Alternative can be selected by the Optimizer by checking on/off
   ☑ Allow Alternative to be chosen as Recommended

2. Indicate if the Start Date of the Alternative can be shifted by checking on/off ☑ Allow Alternative to be Shifted: and specifying the Earliest Start Date and Latest Start Date by clicking on the icon (**this step only applies to projects**).

3. Click "Save".



Important Reminder

Allow Alternative to be chosen as Recommended **-** this box should be checked for all alternatives within an investment **–** if an alternative is no longer viable it should be deleted by contacting the AIP Team. Checking this box means that the alternative and associated funding is a viable option to address the investment need, and may be selected during optimization.

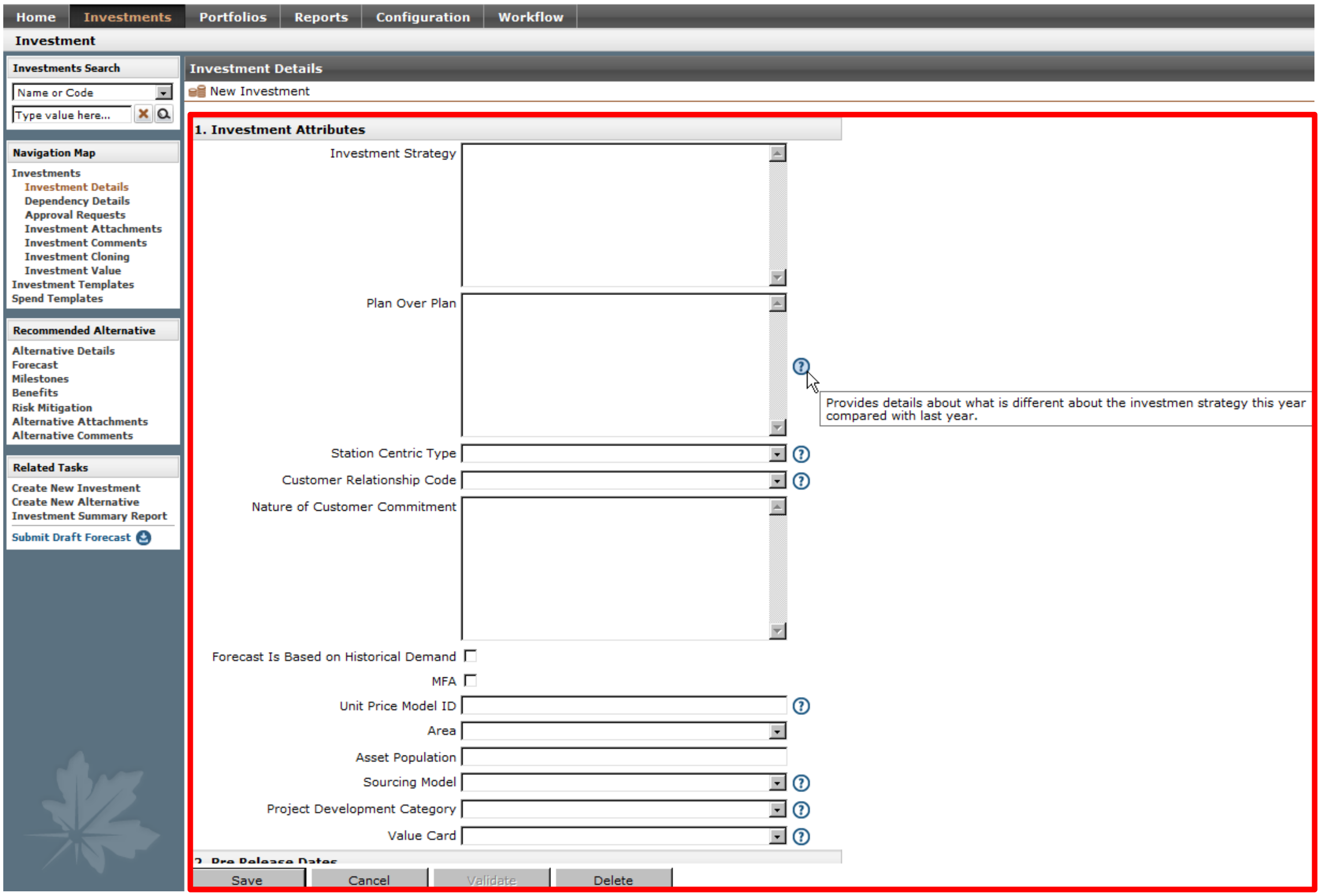
Allow Alternative to be Shifted **–** this box only applies to Project investments and should be checked if it is suitable for the start date to shift during optimization. Note that, the Earliest and Latest Start Date may be specified to **ensure the project does not start either too early or too late**. Furthermore, the **Earliest Start Date must never be earlier than January 1st of the next planning cycle** (e.g. for the 2017 – 2022 plan, this date should never be earlier than January 1, 2017).

4.3.3 INPUT INVESTMENT ATTIRBUTES

Investment Attributes are meant to provide an overview of the investment need/justification (what is the goal of your investment and how does it relate to corporate objectives). Depending on the Investment Type/Stage, the fields available for population may differ.

Instructions

1. Fill out each available field based on its applicability to your investment. Note that, hovering over the (?) icon will reveal a full description of what information is required
2. Click “Save”.

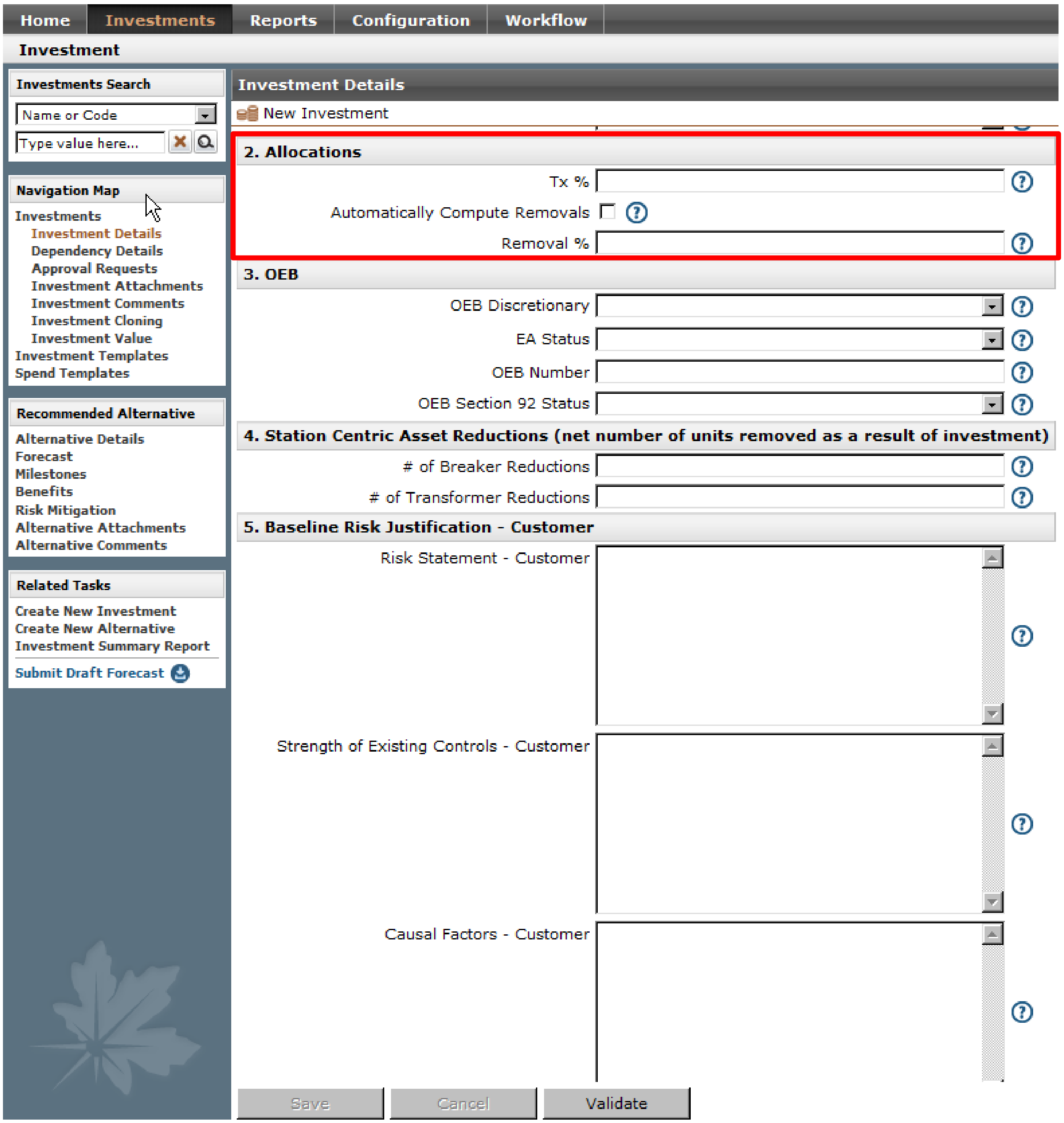


4.3.4 INPUT FINANCIAL ALLOCATIONS

Allocations are used to specify specific percentages that are to be taken into account when calculating/splitting costs of a common investment or accounting for removals. **Note that, Tx% must be populated for common investments** (investments that belong to N.C drivers) or the investment will not appear in the accomplishment file.

Instructions

1. Fill out each available field based on its applicability to your investment. Note that, hovering over the ⓘ icon will reveal a full description of what information is required
2. Click "Save".

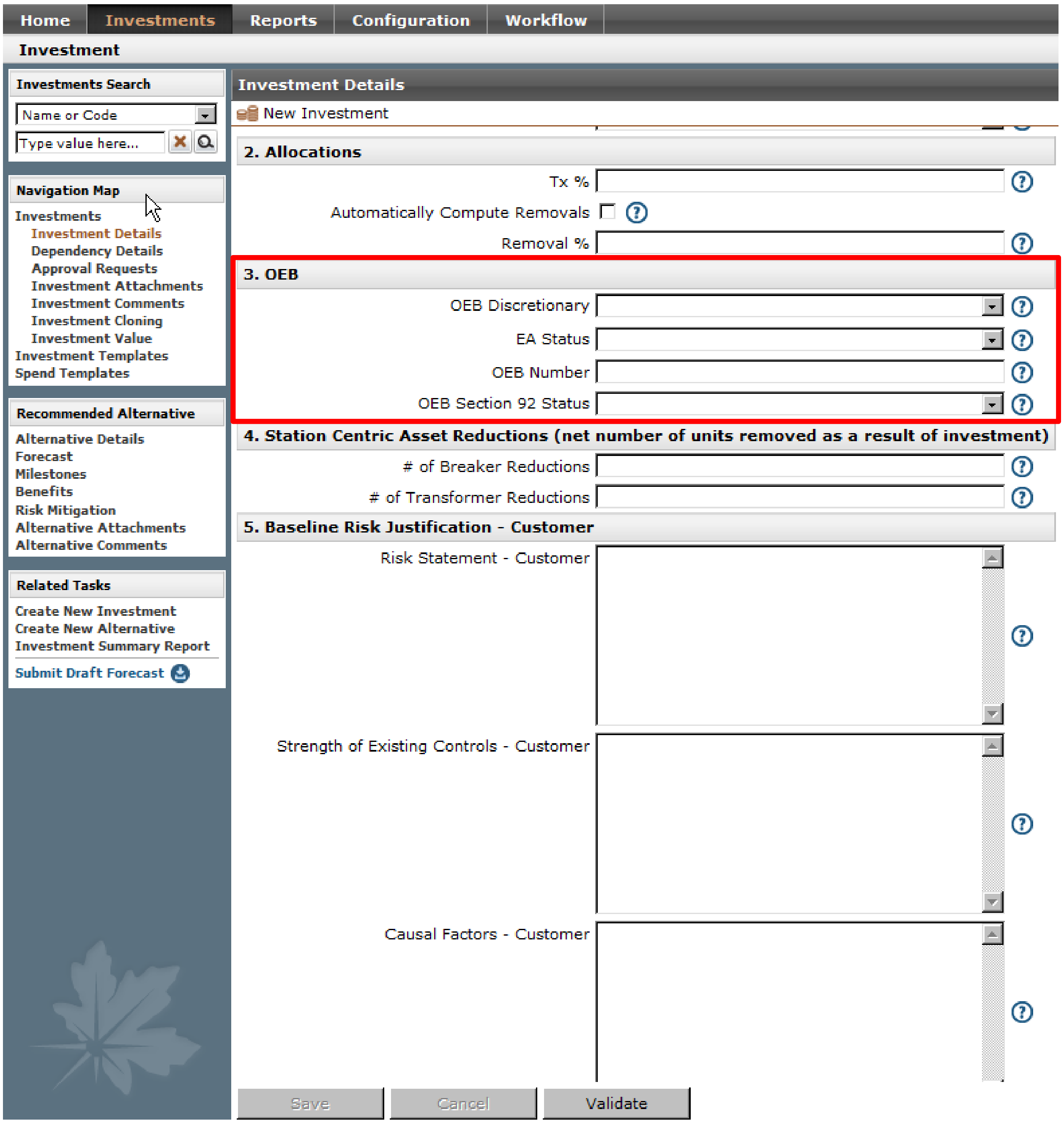


4.3.5 INPUT OEB INFORMATION

The OEB section is used to capture any information that pertains to OEB requirements.

Instructions

1. Fill out each available field based on its applicability to your investment. Note that, hovering over the ? icon will reveal a full description of what information is required
2. Click "Save".

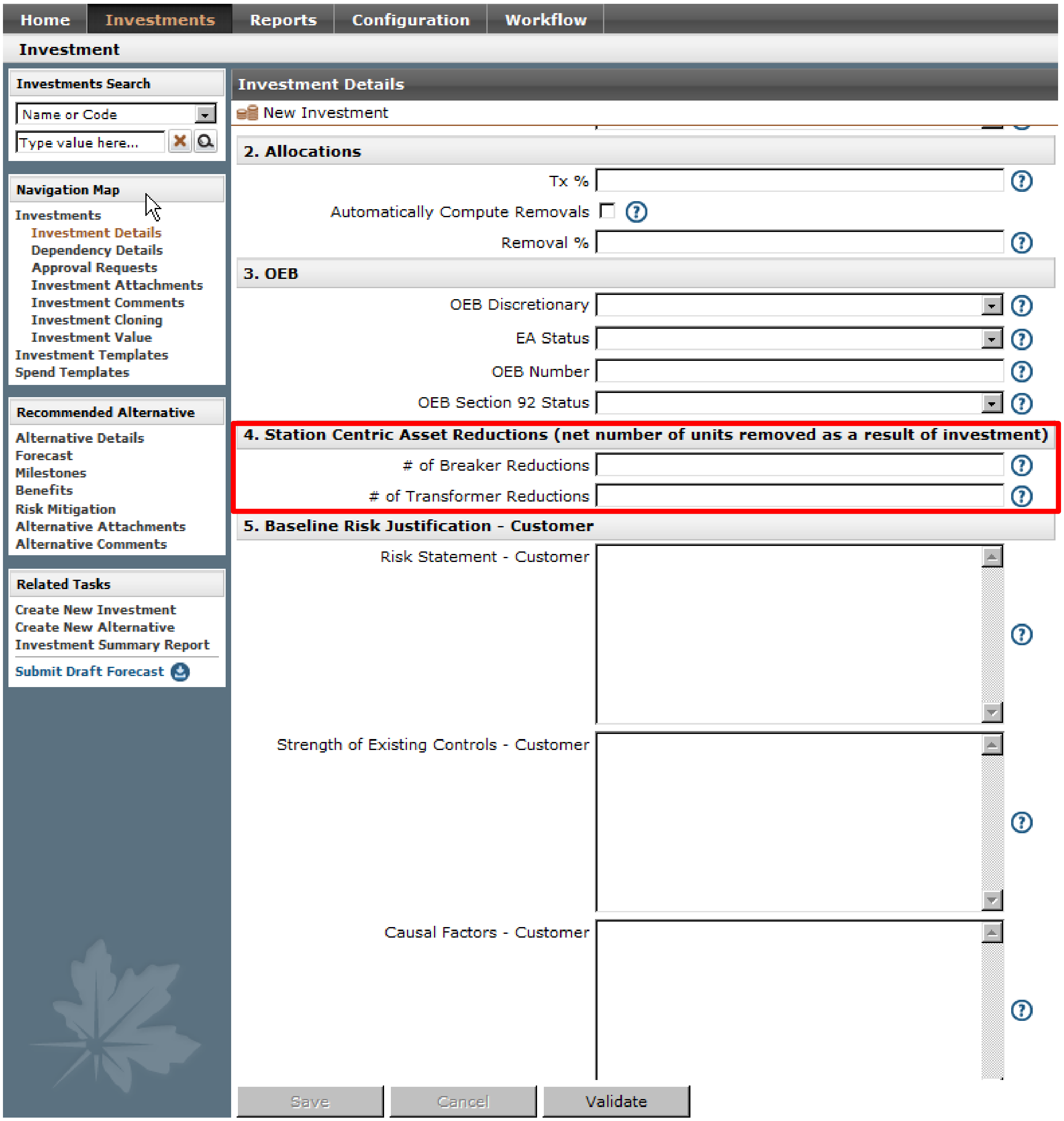


4.3.6 INPUT STATION CENTRIC ASSET REDUCTIONS

The Station Centric Asset Reductions section is used keep track of net asset reductions as a result of **station centric component replacement/refurbishment investments** (only applies to Tx Capital Sustainment)

Instructions

1. Fill out each available field based on its applicability to your investment. Note that, hovering over the icon will reveal a full description of what information is required
2. Click "Save".

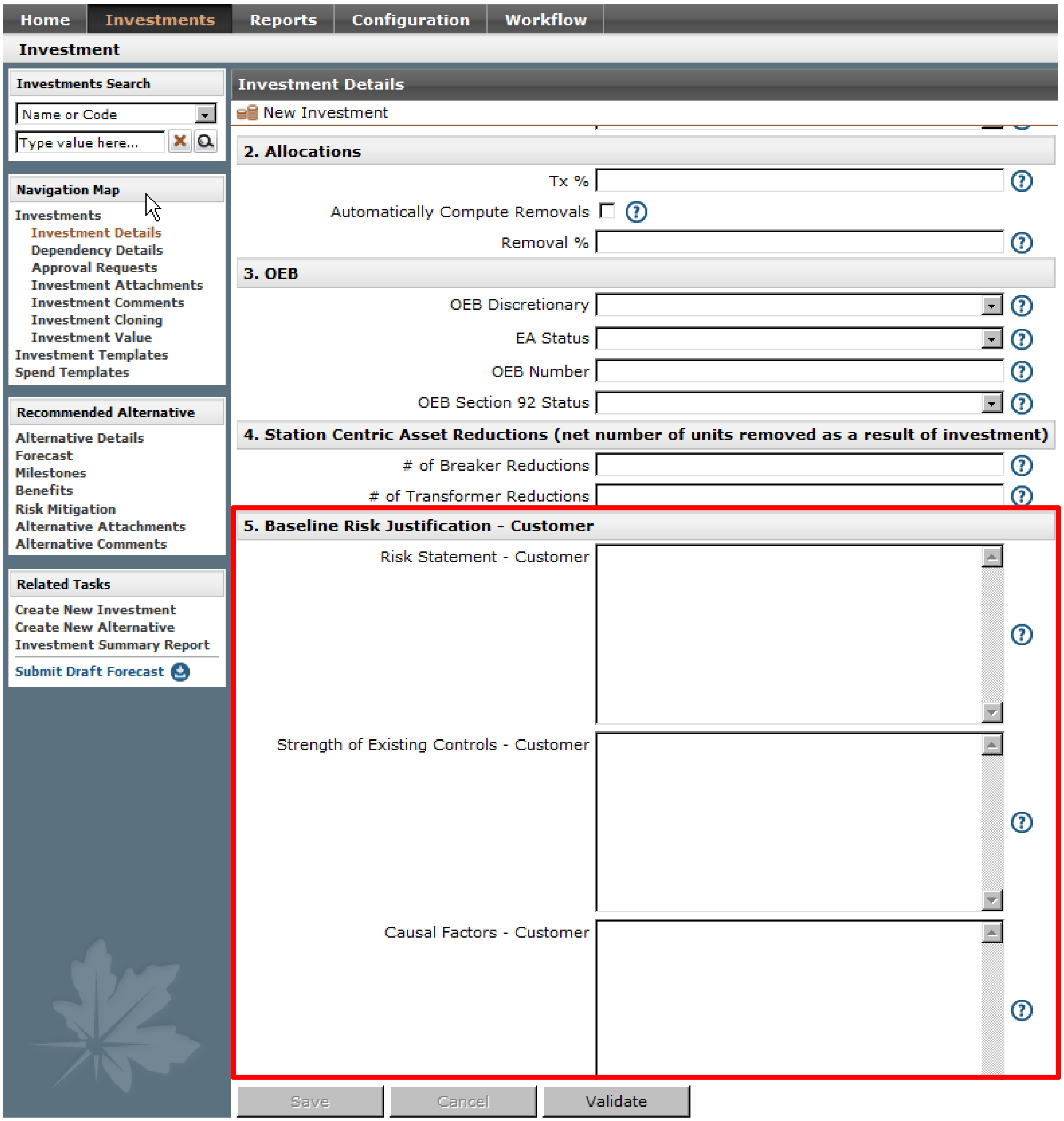


4.3.7 INPUT BASELINE RISK JUSTIFICATION

The Baseline Risk Justification section is used to document how you arrived at your baseline risk assessment. This section should be filled out **for each corporate value** you have identified in your baseline risk assessment.

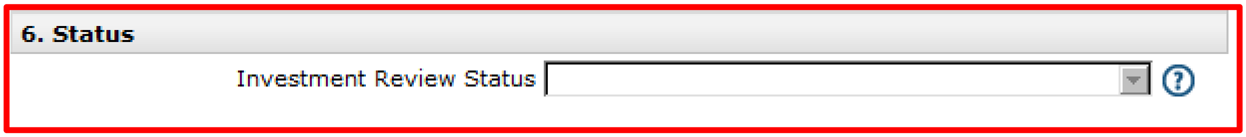
Instructions

1. Fill out each available field based on its applicability to your invesment. Note that, hovering over the ⓘ icon will reveal a full description of what information is required
2. Click "Save".



4.3.8 VIEW INVESTMENT REVIEW (WORKFLOW) STATUS

The Status section is meant to capture the current state of the investment once it has been routed through workflow and is automatically updated. **No input is required.**



4.4 ADD INVESTMENT ATTACHMENTS

Supporting document can be attached to an investment/alternative to provide additional detail / justification.

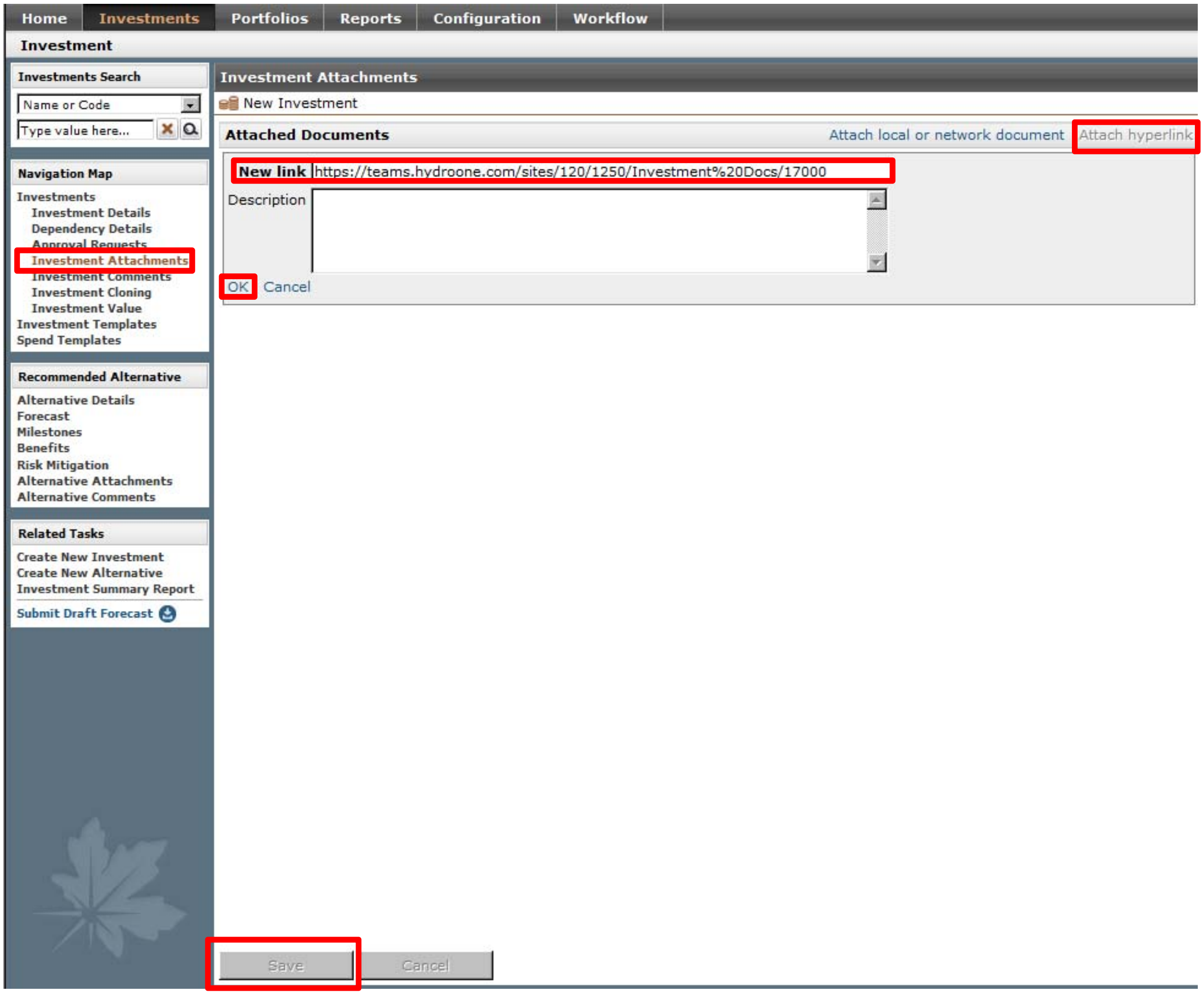
Examples of supporting documentation may include:

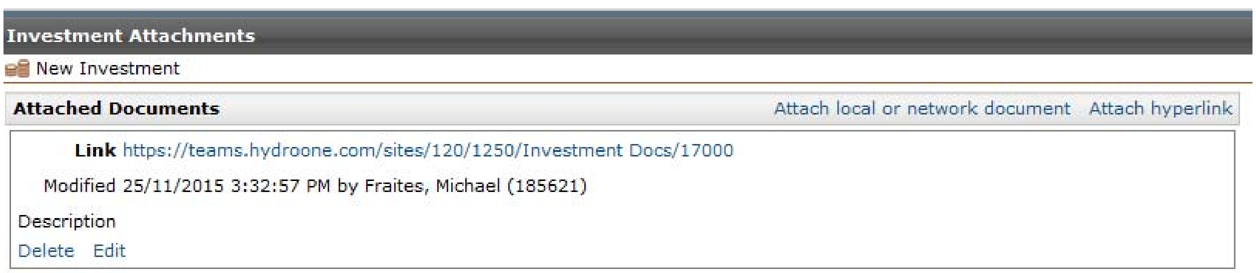
- Investment Summary Report
- Asset Analytics BI Repots (BI Report – AA 221 v.01)Risk assessment calculations/justifications
- Scope of work
- Estimates

4.4.1 ATTACH A LINK TO AN INVESTMENT

Instructions

1. Uploadthe appropriate documents to the correct AR folder within the AR Docs SharePoint library. If an AR folder does not yet exist, create a new one using the AR number assigned to the investment. If the AR has not yet been created, create a new folder and use the AIP Code as the folder name.
2. Click on the **<Investment Attachments>** link in the left hand menu on the Investment.
3. Click "**Attach Hyperlink**"
4. Copy this URL '**https://teams.hydroone.com/sites/120/1250/Investment%20Docs/**"and add your AR Number or AIP Code (depending on what was used in step one)
5. Pastethe complete URL (e.g. **https://teams.hydroone.com/sites/120/1250/Investment%20Docs/17000**)into the field "**New Link**"
6. Enter an optional description.
7. Select **<Ok>**
8. Click < Select **<Save>**


Home
Investments
Portfolios
Reports
Configuration
Workflow
Investment
Investments Search
Name or Code
Type value here...
Investment Attachments
New Investment
Attached Documents
Attach local or network document
Attach hyperlink
Navigation Map
Investments
Investment Details
Dependency Details
Approval Requests
Investment Attachments
Investment Comments
Investment Cloning
Investment Value
Investment Templates
Spend Templates
New link https://teams.hydroone.com/sites/120/1250/Investment%20Docs/17000
Description
OK Cancel
Recommended Alternative
Alternative Details
Forecast
Milestones
Benefits
Risk Mitigation
Alternative Attachments
Alternative Comments
Related Tasks
Create New Investment
Create New Alternative
Investment Summary Report
Submit Draft Forecast
Save
Cancel


Investment Attachments
New Investment
Attached Documents
Attach local or network document
Attach hyperlink
Link https://teams.hydroone.com/sites/120/1250/Investment Docs/17000
Modified 25/11/2015 3:32:57 PM by Fraites, Michael (185621)
Description
Delete Edit

4.5 MODULE 2 – EXERCISE 1

Please refer to handout.

5 MODULE 3: CREATING ALTERNATIVES

What is an Alternative?

An alternative is one of several possible options for undertaking work which will mitigate risk or create value for the organization. **Each investment must have at least one alternative**. The alternative is the entity where the following information is captured:

- Alternative Start Date
- Forecast (Spend and Accomplishment Units)
- Milestones
- Risk mitigation
- Benefits

As part of Optimization, the choice of Alternative or shifting of Alternative Start Date can be changed within an investment to maximize value.

Depending on the investment driver (Demand, Risk, Benefit) and whether the investment need will be addressed via a Program or Project, different Alternative rules apply in terms of alternative requirements. The chart below maps out examples of alternative requirements / "shift-ability" requirements for the majority of investments:

Driver	Project/Program	Type	Cost Model	Forecast Accomplishment Type	Alternatives	Shiftable?
Demand	Project	Demand Funnel / Value Based	Estimate	None/*Type B*	1	*Yes*
	Program	Demand	Historical	Type A	1	No
Risk	Project	Value Based	Estimate	None/Type B	1 or more	*Yes*
	Program	Value Based	UPC	Type A or Type B	3	No
Benefit	Project	Value Based	Estimate	None	1	Yes
	Program	Value Based	UPC	Type A	3	No

5.1 ALTERNATIVE DETAILS

5.1.1 INPUT / MODIFY ALTERNATIVE DETAILS

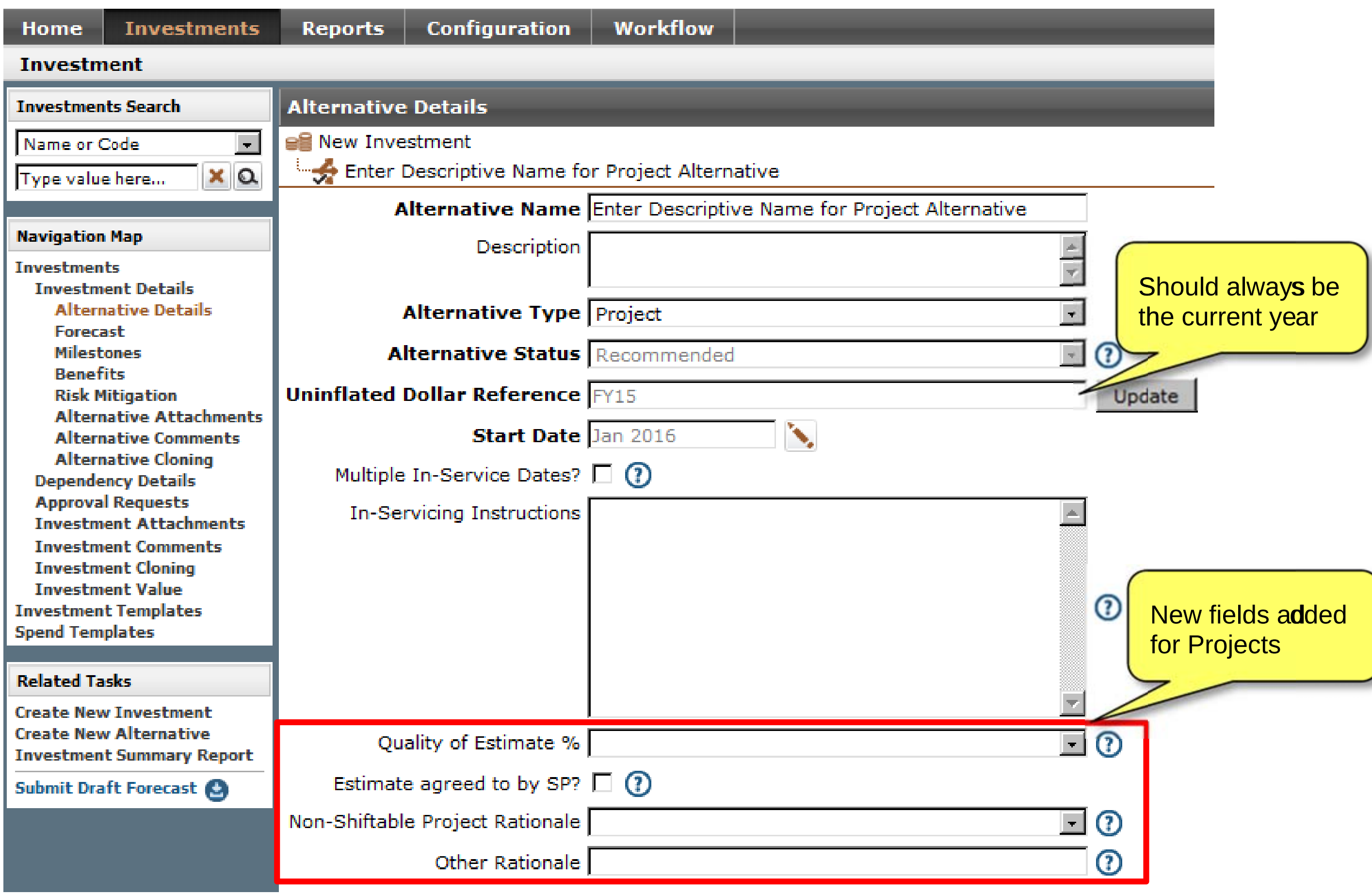
Alternative Details are meant to capture additional information that pertains to the alternative. Depending on the Alternative Type, different fields will be available for population. Note that, hovering over the icon will reveal a full description of what information is required.

Instructions

1. From within an existing investment,find an Alternative you wish to edit and click on the Alternative Name. This will take you to the <**Alternatives Details**> page where you can make the edits.

2. Enter the appropriateinformation as it pertains to your alternative. **Please take special note of changing the Start Date as explained in the section below.**

3. Click “Save”.



Important Reminder:

Uninflated Dollar Reference: For consistency purposes, always click “Update” to set the Uninflated Dollar Reference to the current year. This will determine how inflation is calculated when uninflated $’s are entered.

5.1.2 INPUT / MODIFY ALTERNATIVE START DATE

The Start Date of an Alternative can be modified to reflect when the alternative is envisioned to start. Note that, there are two options to be considered when changing the start date.

Option 1: Change the Start Date of an Alternative and shift the following components in unison:

- Draft Forecast (cash flows and units of accomplishment)
- Milestones
- Benefits
- Risk Mitigation

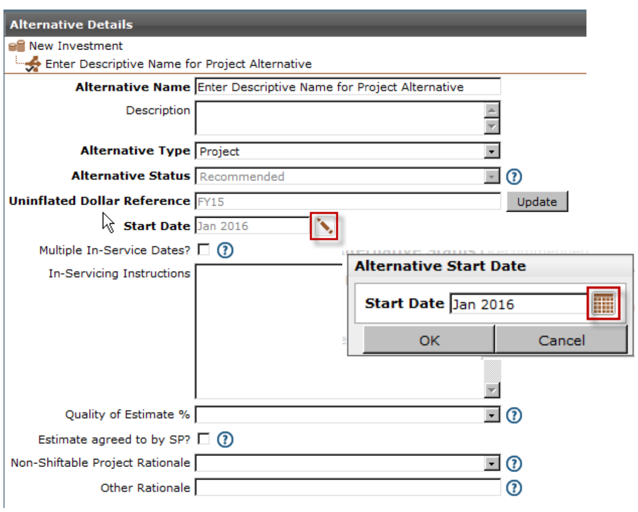
This option is typically used for an alternative that is already setup but needs to be brought forward or postponed. Note that, Start Dates should typically be modified in **one year increments** if this method is used.

Option 2: Change the start date without impacting other data

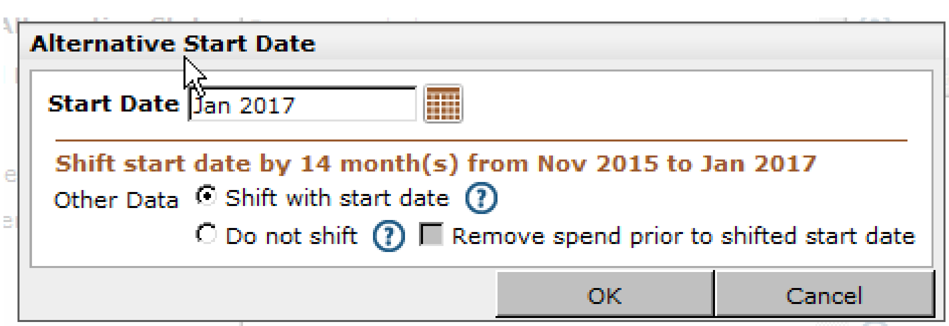
This option is typically used when an alternative is already setup with the cash flows/units in the correct year but an incorrect Start Date. In this case, you may want to adjust the Start Date so that it is in line with the first year of spend.

<u>Instructions</u>

1. Click on the  icon next to the Start Date
2. Select a new Start Date by clicking the  icon



3. The Alternative Start Date window will expand to show options of shifting the dates of all investment data or preserving them



4. Select the option "**Shift with start date**" to shift the other alternative data in unison with the start date (e.g., Cashflows, Milestones, etc.)

5. Select the option “**Do not shift**” to shift the start date without modifying the spend forecast.
6. Optional: If there are spend forecasts before the new Start Date, checking the "Remove spend prior to shifted start date" checkbox will delete these
7. Click **<OK>** , which will close the Alternative Start Date window.
8. Click **<Save>** at the bottom of the Alternative Details page.

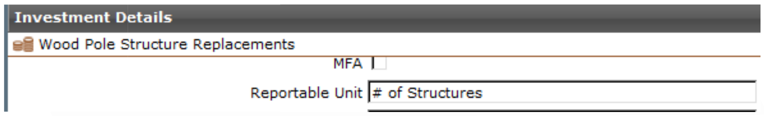
Important Reminder:

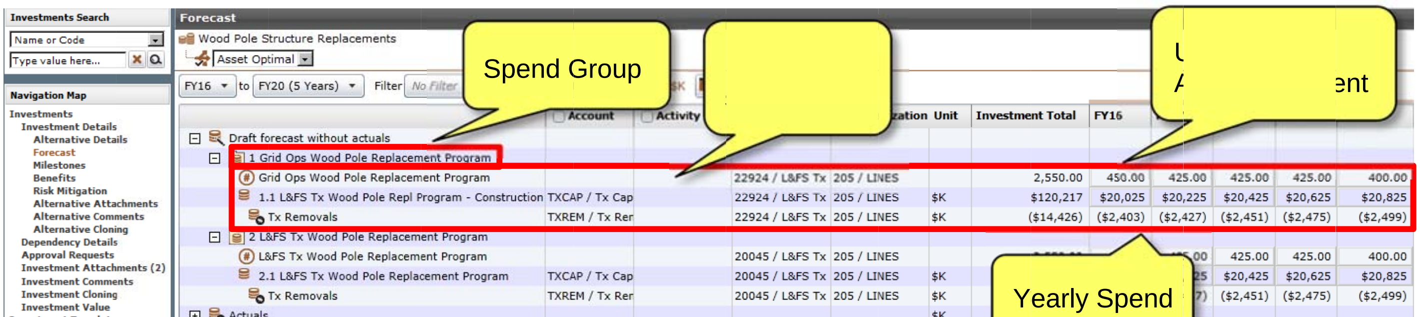
An accurate Start Date for “shiftable” Projects, in combination with a realistic Earliest Start Date and Latest Start Date (specified in the Optimization Options explained earlier) is critical to ensure your investment is not inadvertently shifted before the planning period begins, or outside of the planning window during optimization.

5.2 ALTERNATIVE FORECASTS

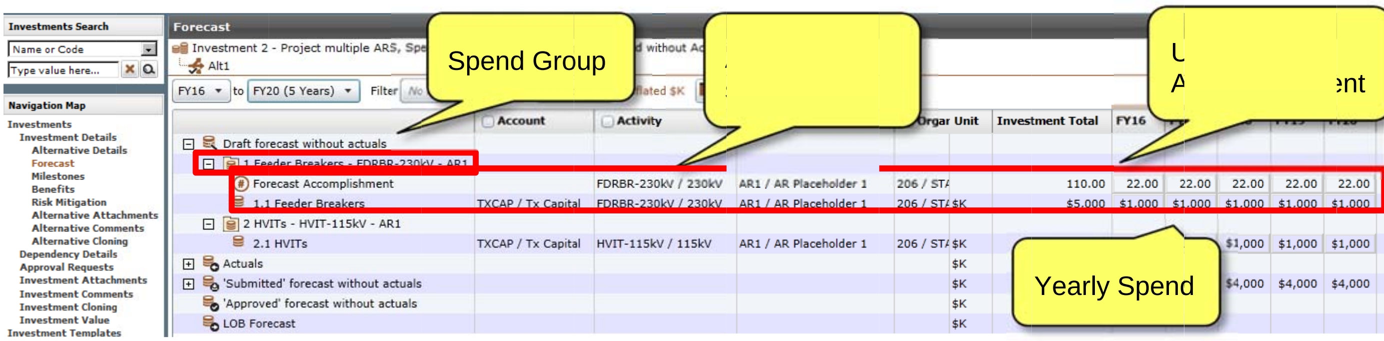
The Alternative Forecasts section is where **cash flows** and **units of accomplishments** (e.g. # of poles) are entered. Forecasts can be entered as a single **Spend Line** where yearly cash flows are recorded, or as part of **Spend Group** which includes a grouping of yearly cash flows related to yearly Forecast Accomplishments. Note that **there are two types of Forecast Accomplishments:**

Type A: no Activity (i.e., specific Asset Type) specified, with the investment field "Reportable Unit" used as the mechanism to describe the type of asset or other unit of accomplishment. Typically used for Programs.





Type B: Activity is specified to provide a more granular breakdown of the asset(s) to be replaced (optional for Programs, mandatory if Forecast Accomplishments are used within Projects)



Both Forecast Accomplishment types have a number of points in common:

- The Forecast Accomplishment and the associated spend lines must use the same AR, Organization and Activity (if used) if they exist in the same spend group
- Multiple Forecast Accomplishments can be entered within an Alternative (e.g. to capture multiple Asset Types)
- **Forecast Accomplishments in Projects do not necessarily need to have a related spend line as they are just meant to capture total units being replaced at a point in time (typically in the year the project is planned to go in-service)**
- An investment / alternative can reference multiple ARs
- An AR can only be referenced in a single investment

Important Reminder:

Units of Accomplishment must match the Reportable Units that is set on the Investment Details screen for **Type A** Accomplishments. Additionally, the Reportable Unit in AIP should also match the Reportable Unit used by Operations.

5.2.1 INPUT / MODIFY SPEND GROUP

A Spend Group is used to group multiple Spend Lines or, Spend Lines and a Forecast Accomplishment. The Spend Group and associated Spend Lines/Forecast Accomplishments should already exist if you are modifying an investment or if you created an investment from a template/cloned investment.

Instructions

1. From within an existing Investment,select **<Forecast>.** This will take you to the <Forecast> page of the **Recommended Alternative** where you can make modifications. Note that, you can change the Alternative by clicking on the drop-down menu under the investment name, and selecting a different alternative below.

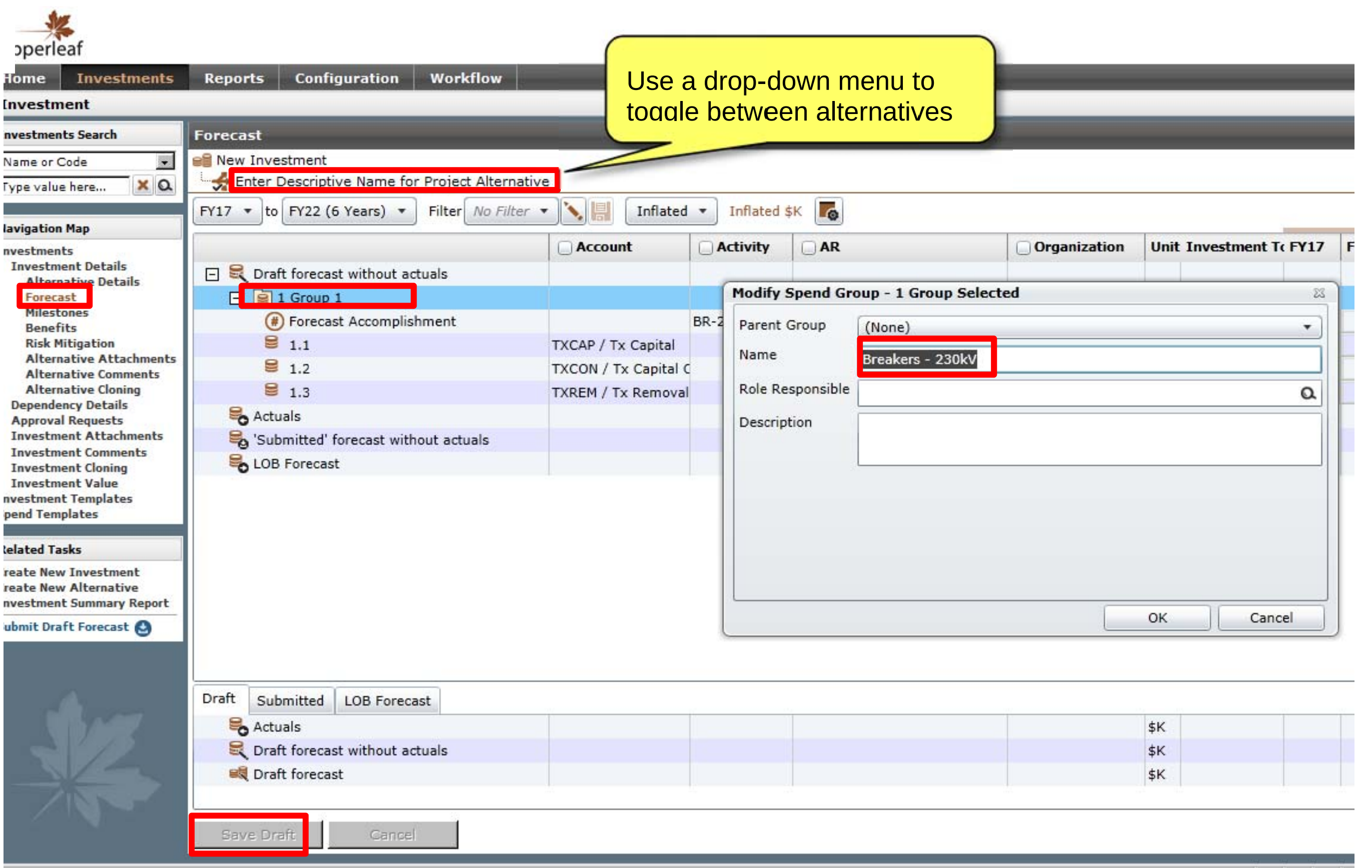
2. Providea meaningful name to the **Spend Group** (typically the AR Name or Forecast Accomplishment Name)

   a. Double-click on the **Spend Group**

   b. Enter name that describes the costs and/or forecast accomplishments in the group (typically, the AR name is entered as the group name unless the Spend Group is used to indicate a Tx Capital Sustainment Project asset replacement in which case, the name of the Spend Group is typically *Asset Type – Voltage [e.g. Metal Clad Breakers – 230kV]*)

   c. Click **Ok**.

3. Click"**Save Draft**".



5.2.2 INPUT / MODIFY FORECAST ACCOMPLISHMENTS

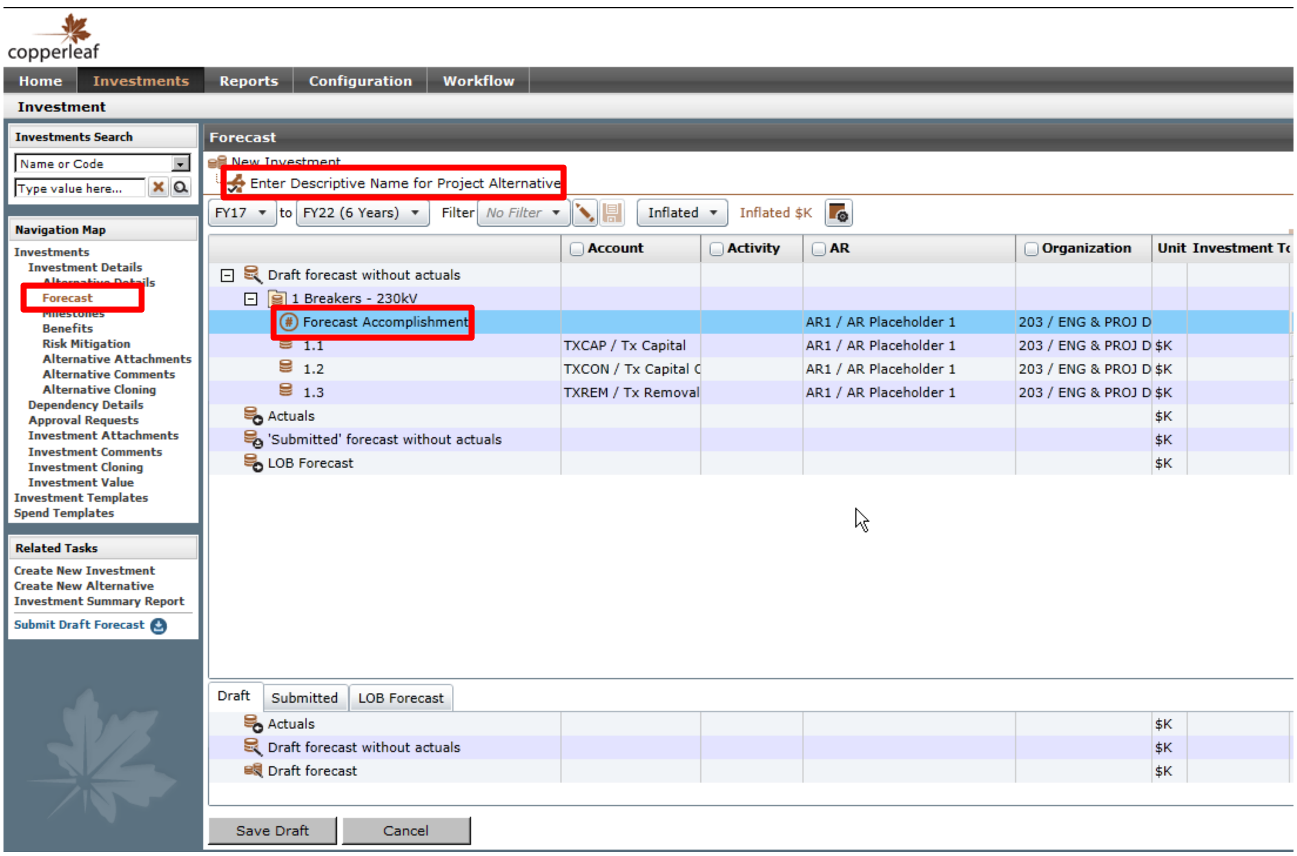
Note: If your investment does not contain Forecast Accomplishments, please skip to the next section.

A Forecast Accomplishment is used to capture yearly units of accomplishment (e.g., # of poles, # of breakers, etc.). The level of granularity will differ depending on the type of Accomplishment being entered. Refer to the Alternative Forecast section above for a detailed breakdown.

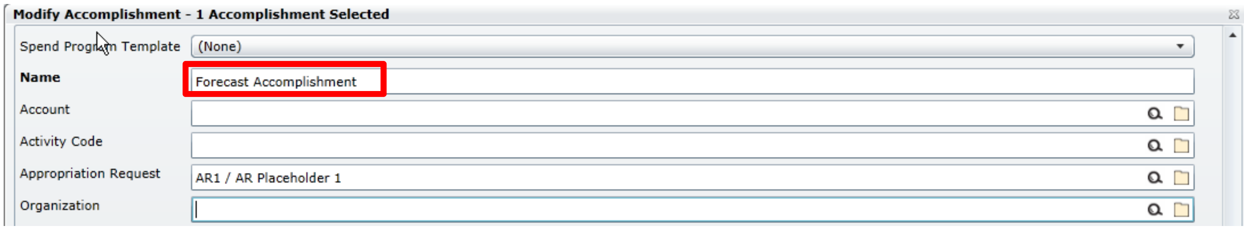
Note that, for **Projects that contain Forecast Accomplishments, Type B Accomplishments**. The total sum of each accomplishment should be entered in the year the Project is planned to go in-service unless yearly accomplishments are known (refer to section 9.1 for samples of each). Units of Accomplishment for these types of investments do not need to correspond with yearly cashflows like they do for Programs. Additionally, multiple Forecast Accomplishments can be entered to capture all asset types that are being replaced.

Instructions

1. From withinan existing Investment, select **<Forecast>.** This will take you to the <Forecast> page of the Recommended Alternative where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Set the **future years** to the Planning Period (e.g. 2016 to 2020)
3. Double-click on the **Forecast Accomplishment** you wish to modify.



4. Provide a meaningful name for the **Forecast Accomplishment** if desired.
    a. Enter a name that describes the Forecast Accomplishment
    b. Click **Ok** if you have finished entering the required Forecast Accomplishment information.



5. Select the **Activity Code** (Asset Type) that applies to the Forecast Accomplishment (**applies to Type B Accomplishments Only**). For traditional programs this will most likely be blank.

   a. Click on the  button in the "**Activity Code"** field to browse the Asset Type hierarchy

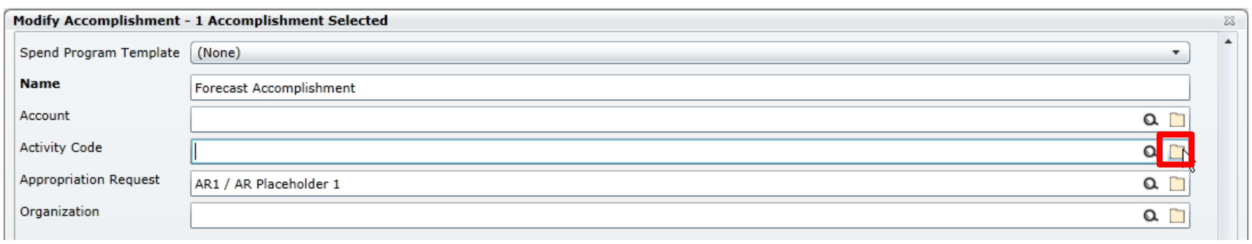
   b. Click on **Activities**

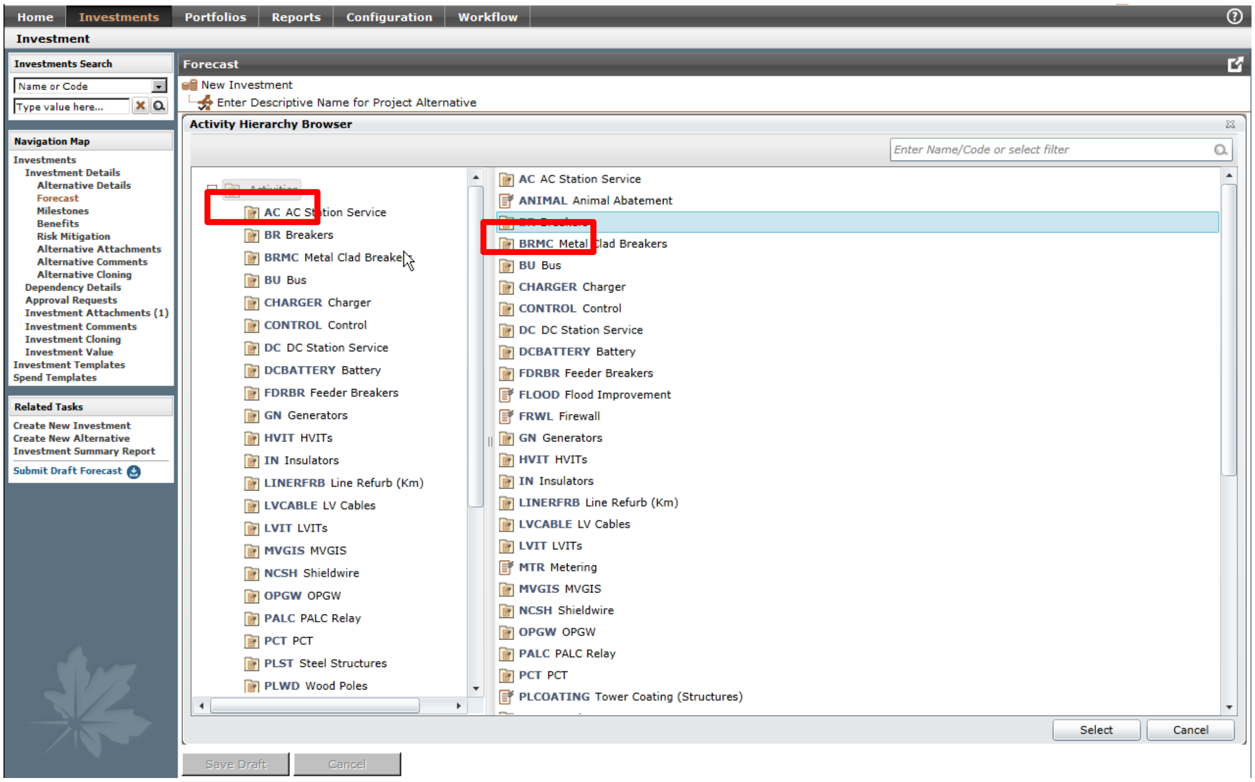
   c. Double-click on the  button to display the lower level activities (e.g. 115Kv breakers, 230kv, etc.)

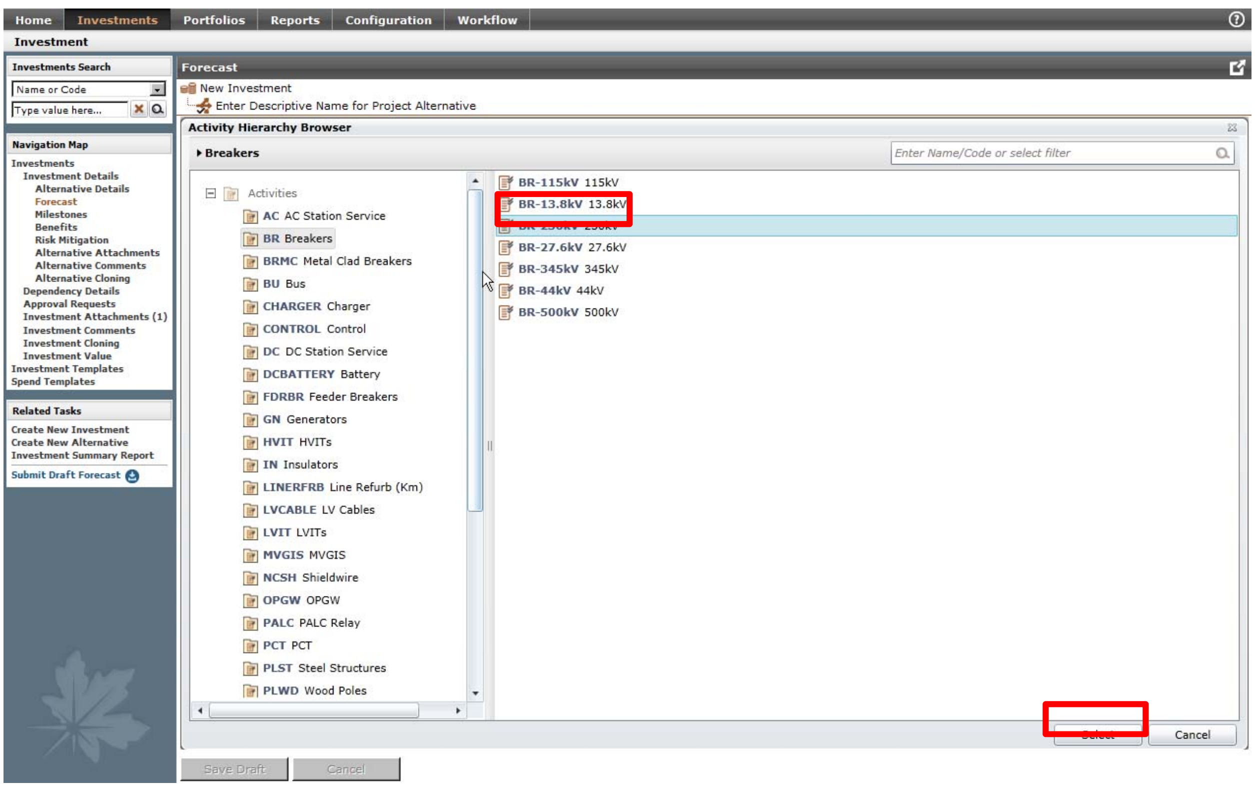
   d. click on the  button to select the Asset Type

   e. Click **Select**

   f. Click **Ok** if you have finished entering the required Forecast Accomplishment information.







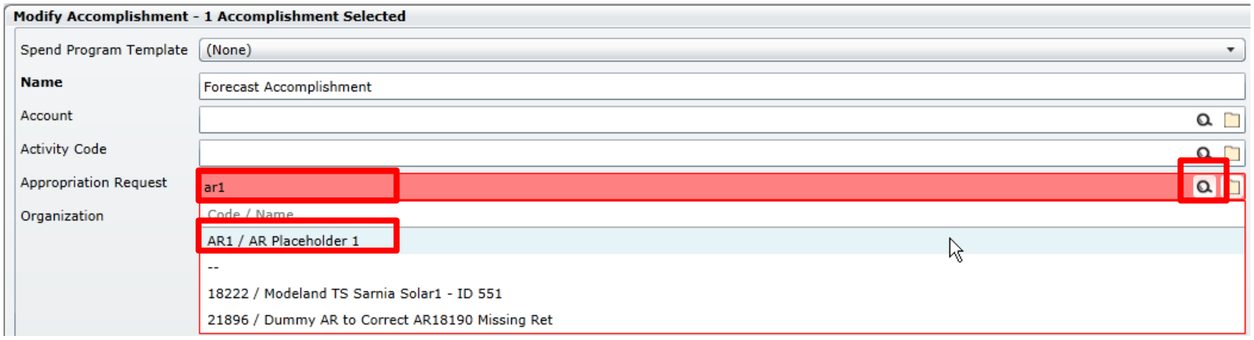
6. Select the **AR** that applies to the Forecast Accomplishment

   a. Enter the AR number in the field **"Appropriation Request"**

   b. Click the 🔍 button

c. Select the AR that matches your entry in Step A

d. Click **Ok** if you have finished entering the required Forecast Accomplishment information.



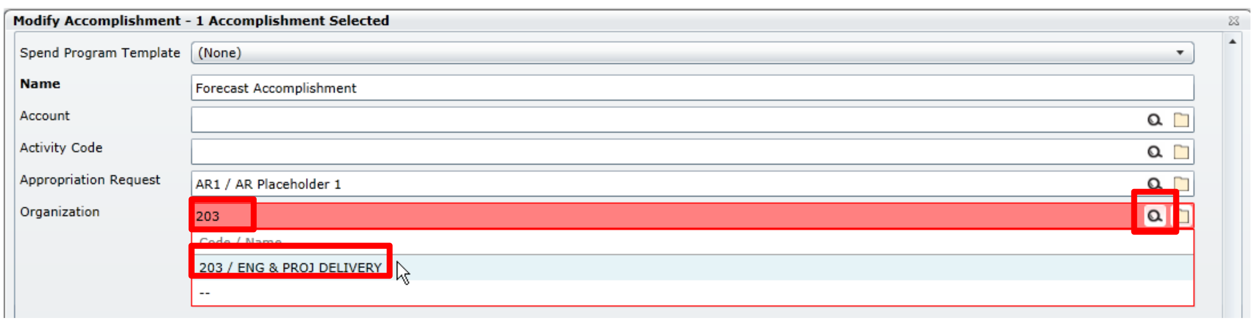
7. Select the **Organization (LOB)** that applies to the Forecast Accomplishment

a. Enter the Organization number in the field **"Organization"**

b. Click the button

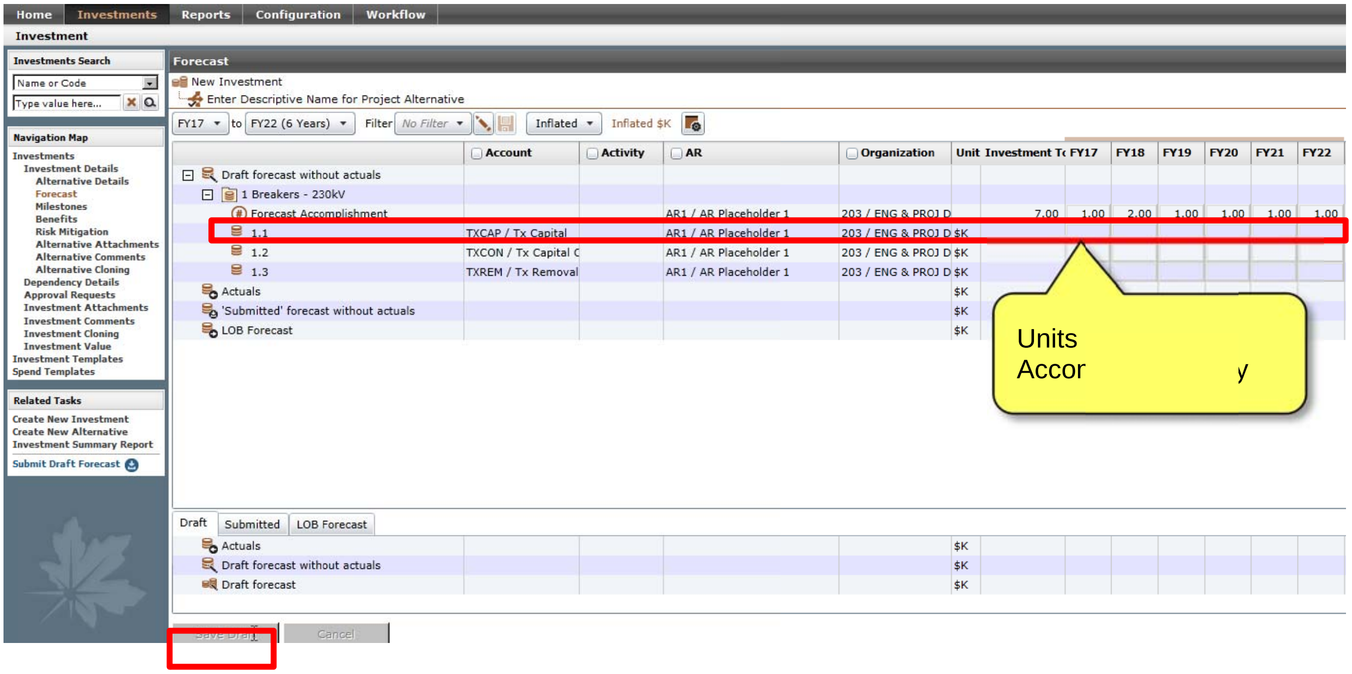
c. Select the **Organization** that matches your entry in Step A

d. Click **Ok** if you have finished entering the required Forecast Accomplishment information.



8. Enter the units of work that will be accomplished in each year (or in the in-service year for Station Bundles or Line Refurb projects)

9. Click the **Save Draft** button



Important Reminder:

Any Forecast Accomplishment/Spend Line(s) that exists in the same Spend Group **MUST** reference the same Activity Code.

All Project Forecast Accomplishments (Type B) **MUST** specify an Activity Code

Tx Station and Line Refurbishment Forecast Accomplishment **do not** have to have associated spend

Anytime a Forecast Accomplishment change is made, a cash flow change **MUST** be made (e.g. adding a penny) and **the investment must be submitted** to ensure the revised Forecast Accomplishment is reflected in the Accomplishment File.

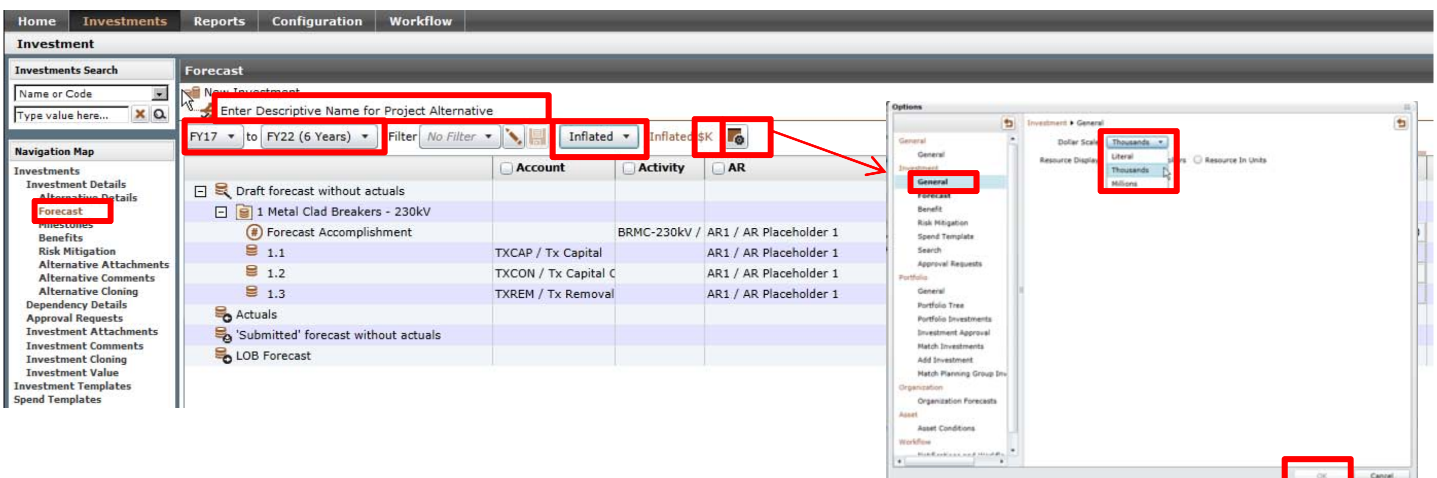
5.2.3 INPUT / MODIFY CASH FLOWS (SPEND LINES)

Spend Lines are used to capture yearly program/project costs.

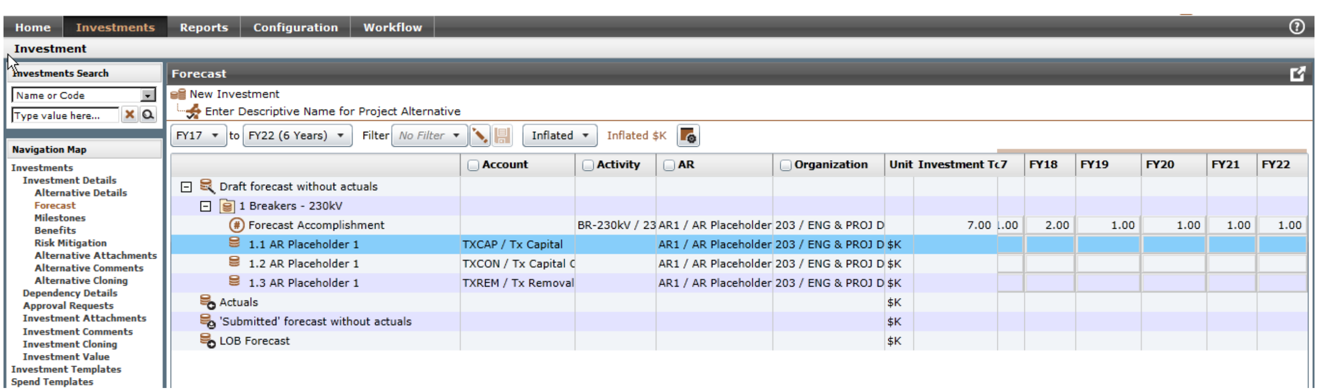
Spend Guidelines
Costs should be entered as: • Inflated dollars for Projects • Uninflated dollars for Programs Removals, Capital Contributions and OMA Recoveries: • Enter as separate spend lines (but under the same group name) • Enter as negative values Common costs: • Are entered under the appropriate Common Account (CAP vs. OMA) on their own spend line • Are automatically split between Dx and Tx based on the % entered in the 'Tx %' field on the Investment Detail Screen when you click 'Save Draft' (the tool creates an additional spend line removing the common cost and another allocating it)

Instructions

1. From within anexisting Investment, select **<Forecast>.** This will take you to the <Forecast> page of the Recommended Alternative where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Set the **future years** to the Planning Period (e.g. 2017 to 2022)
3. Select **Inflated** Dollars for Projects and **Uninflated** dollars for Programs
4. Take note of the **Dollar Scale** (default is $K). To change the Dollar Scale, click on the icon, select **General**, choose the **Dollar Scale** from the drop-down menu and click **Ok**.



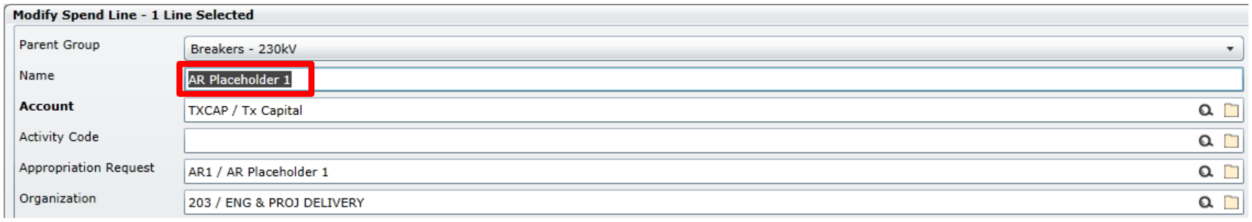
5. Double click on the appropriate **Spend Line**



6. Provide a name for the **Spend Line**

   a. Enter name that describes the Spend Line (e.g. AR Name)

   b. Click **Ok**



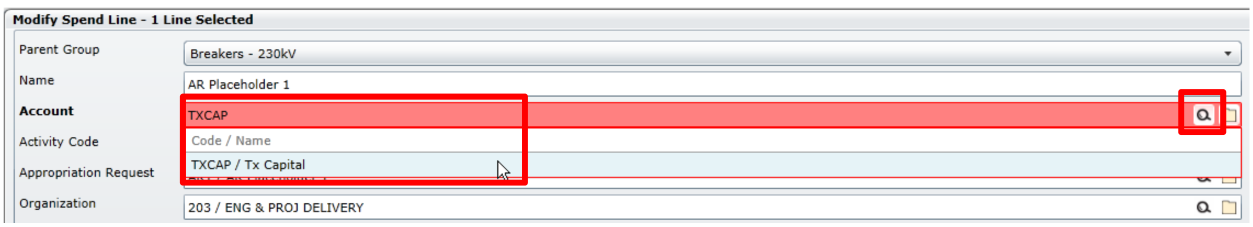
7. Confirm the **Account Code** is correct based on the Spend you are entering. If the Account Code is incorrect, follow the steps below. A complete list of Account Codes is contained in the Appendix.

   a. Enter the Account Code (e.g. TXOMA, DXOMA, TXCAP, DXCAP, etc.) in the field "**Account**"

   b. Click the  button

   c. Select the Account Code that matches your entry in Step A

   d. Click **Ok** if you have finished entering the required Spend Line information.



8. *Select the **Activity Code** (Asset Type) that applies to the Spend Line - **rare** (**only applies if Type B Accomplishments are used**)*

   a. *Click on the  button in the "**Activity Code"** field to browse the Asset Type hierarchy*

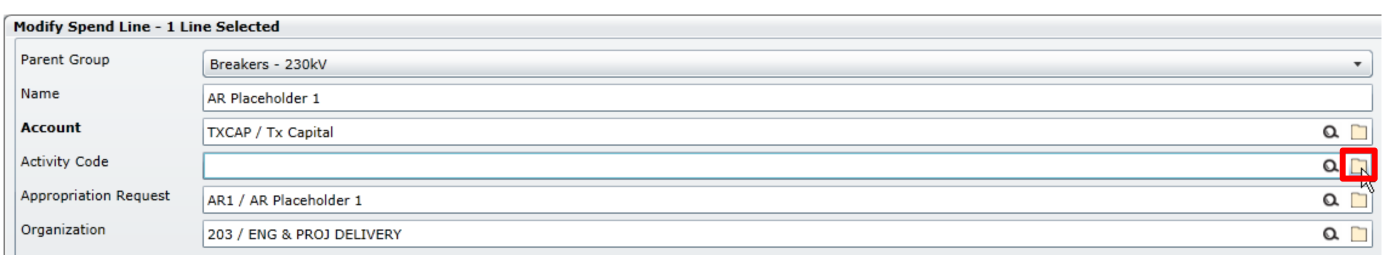
   b. *Click on **Activities***

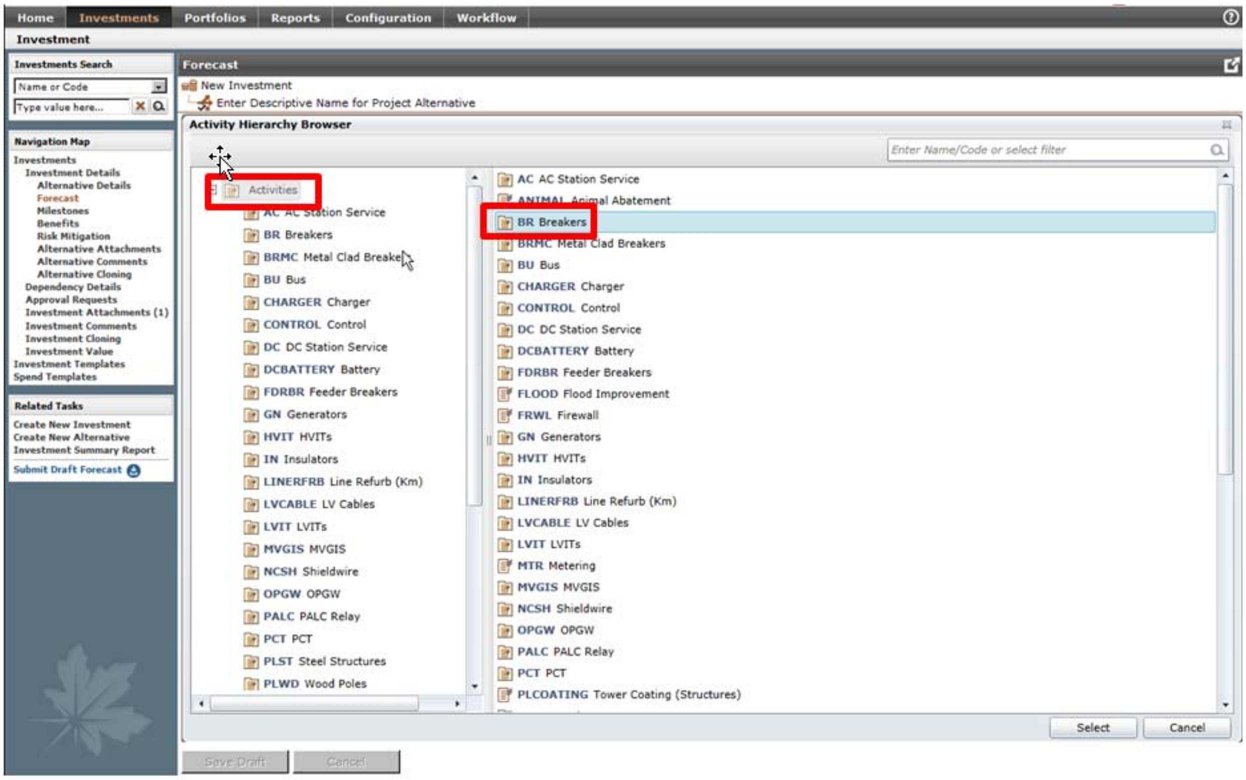
   c. *Double-click on the  button to display the lower level activities (e.g. 115Kv breakers, 230kv, etc.)*

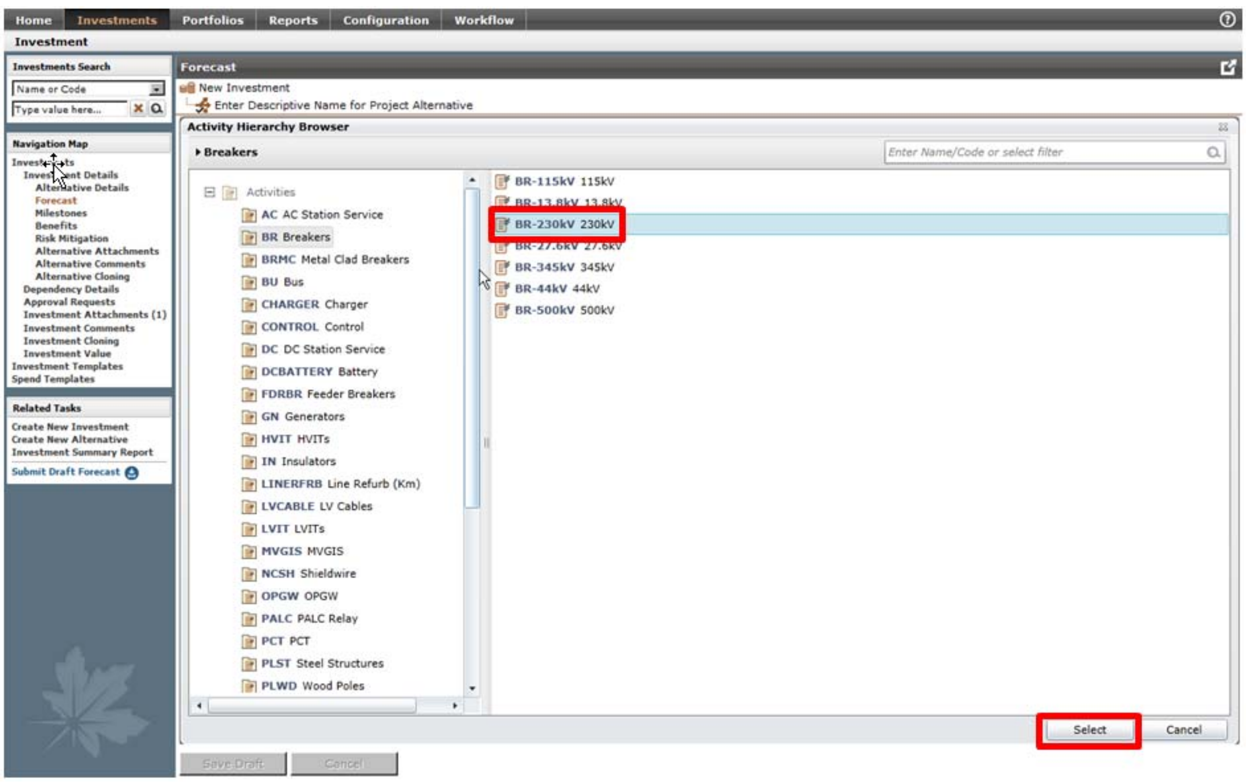
   d. *click on the  button to select the Asset Type*

   e. *Click **Select***

   f. *Click **Ok** if you have finished entering the required Spend Line information.*







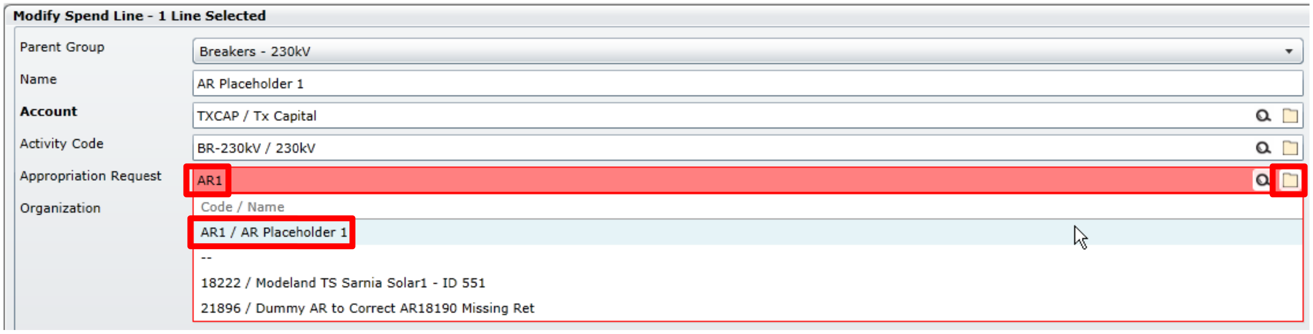
9. Select the **AR** that applies to the Spend Line

   a. Enter the AR number in the field **"Appropriation Request"**

   b. Click the  button

c. Select the AR that matches your entry in Step A

d. Click **Ok** if you have finished entering the required Spend Line information.



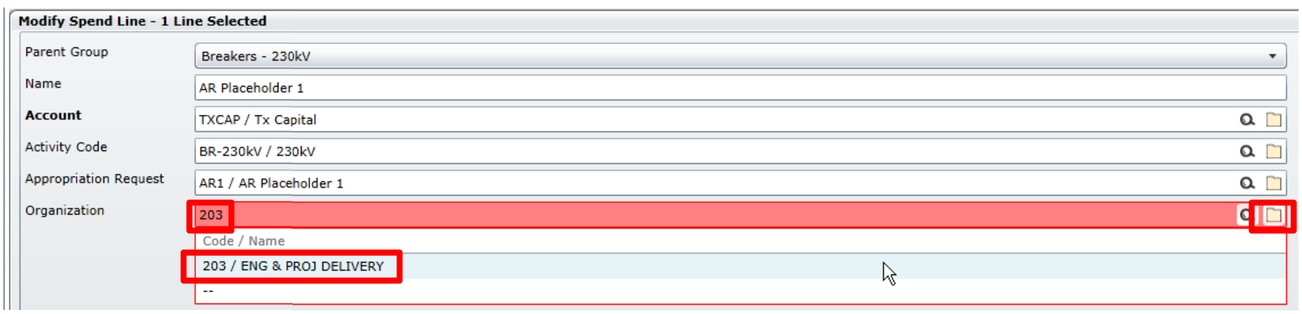
10. Select the **Organization (LOB)** that applies to the Spend Line

a. Enter the Organization number in the field **"Organization"**

b. Click the button

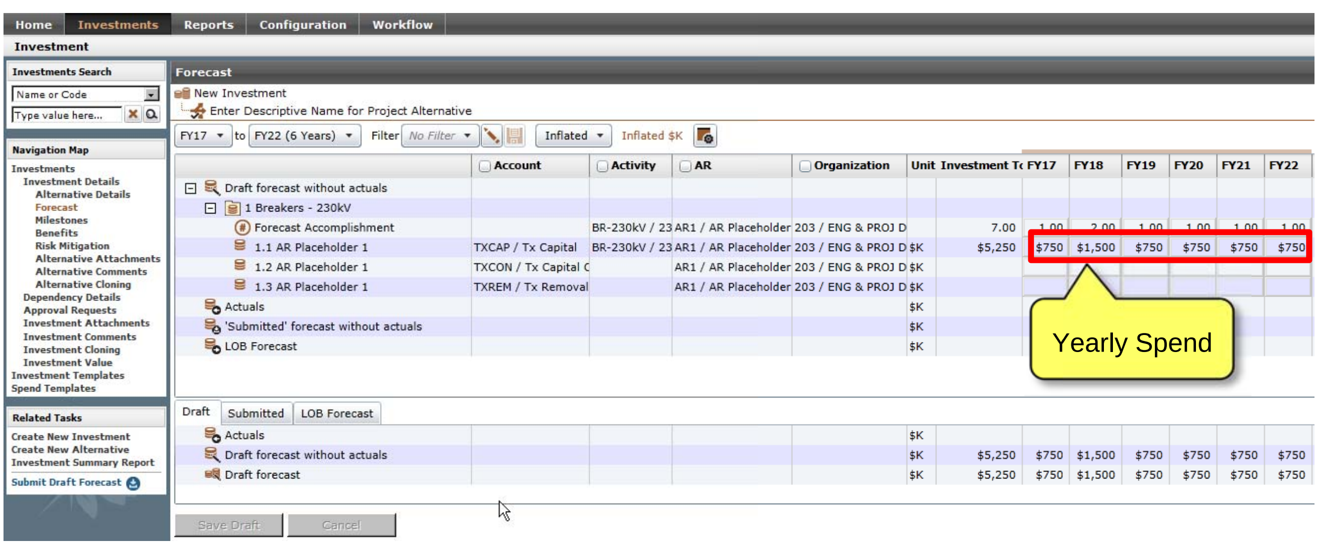
c. Select the **Organization** that matches your entry in Step A

d. Click **Ok** if you have finished entering the required Spend Line information.

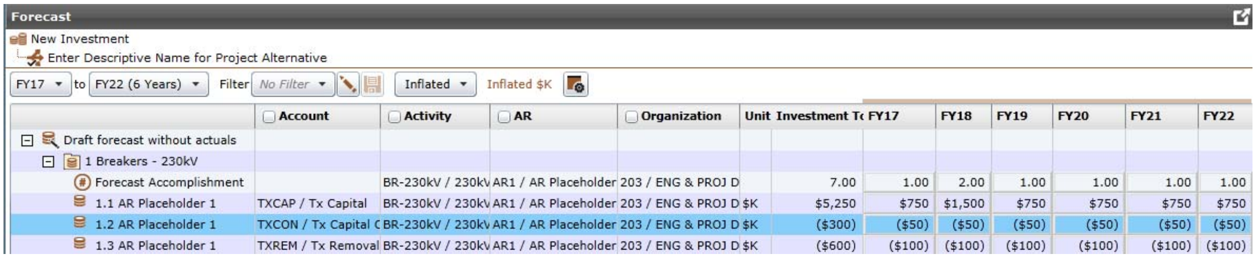


11. Enter the yearly spend. Ensure it corresponds with the Forecast Accomplishment (if applicable)

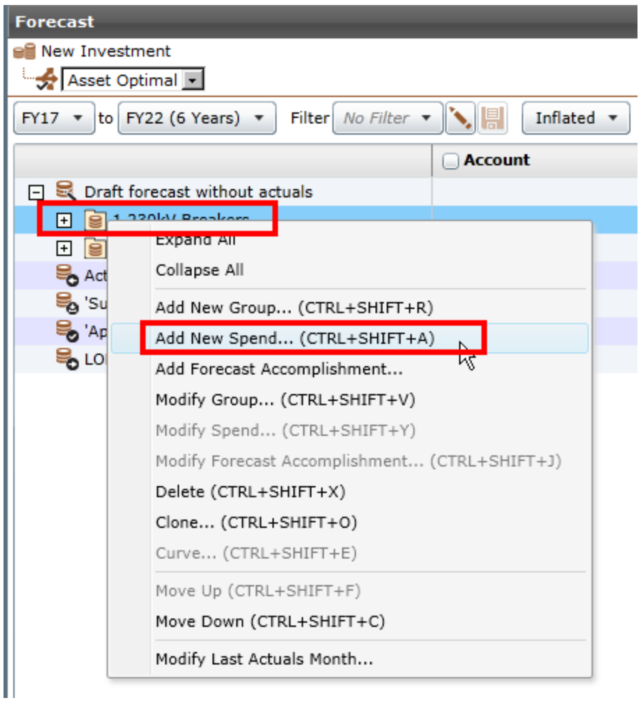
12. Click the **Save Draft** button



13. If Removals or Capital Contributions apply to your investment, follow the steps outlined above to modify each Removal/Capital Contribution Spend Lines (see completed example below)



14. If a new Spend Line needs be added, highlight the Spend Group where it is to be added and click "**Add New Spend…"**



15. Follow the steps outlined above to modify your Spend Line

16. Once all Spend Lines have been entered, click "**Submit Draft Forecast"** on the lower left hand menu. This will ensure your latest Forecast modifications are reflected in the Accomplishment File.

Important Reminder:

Inflated Dollars signifies that inflation has already been accounted for in the yearly cash flows entered in AIP

Uninflated Dollars signifies that inflation has not been accounted in the yearly cash flows, and therefore, AIP will "inflate" these costs based on the inflation rates provided by the Business Planning and configured in AIP

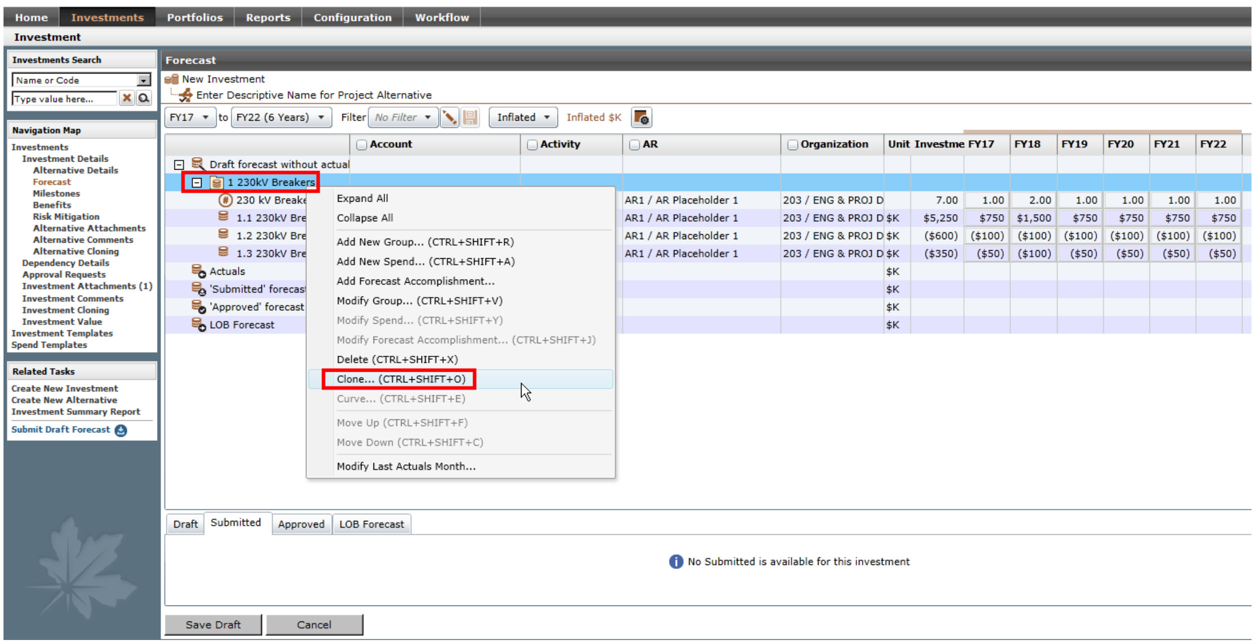
A **Spend Line** is required for each type of cost (e.g. Gross, Removals, Capital Contributions, Recoveries)

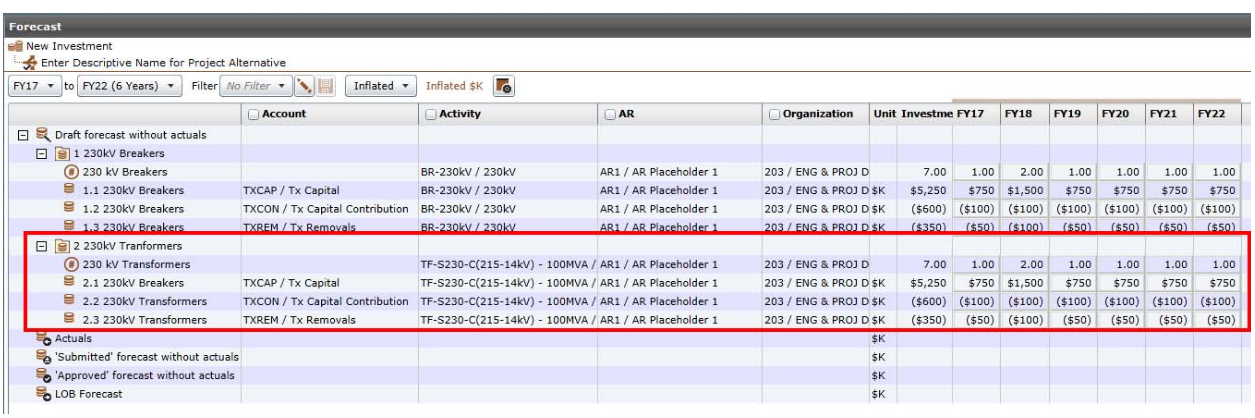
Always Submit your Draft Forecast when you are done making changes.

5.2.4 ADD ADDITIONAL FORECAST ACCOMPLISHMENTS / SPEND LINES

In cases where an investment will be constructed using multiple Forecast Accomplishments/Spend Lines (e.g. Tx Station Bundle, Line Refurbishment projects), the best approach is to clone a Spend Group that already contains the required information (e.g. Account, AR, Organization) and then modify the name and Activity of the Spend Group, Forecast Accomplishment and Spend Line by following the steps outlined above.

1. From within an existing Investment, select **<Forecast>.** This will take you to the <Forecast> page of the Recommended Alternative where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Right-click on the Spend Group you wish to clone
3. Click "**Clone…**"
4. Follow the steps outlined in the section above to modify the **Forecast Accomplishments**/**Spend Lines** within the cloned **Spend Group**



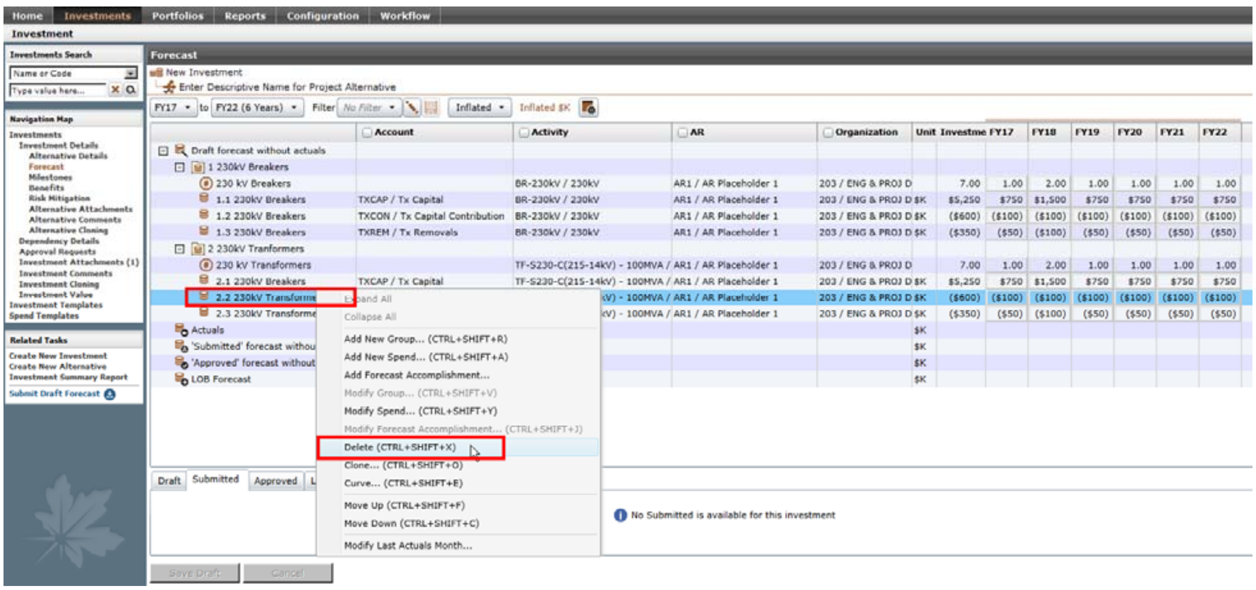


5.2.5 DELETE A SPEND GROUP/ SPEND LINE / FORECAST ACCOMPLISHMENT

In some cases, not all Spend Lines/Forecast Accomplishments included in an Investment Template or cloned investment are applicable (e.g. Capital Contributions) and need to be deleted.

1. From within an existing Investment, select **<Forecast>.** This will take you to the <Forecast> page of the **Recommended Alternative** where you can make modifications. Note that, you can change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.

2. Right click on the **Spend Group, Spend Line** or **Forecast Accomplishment** you wish to delete and click **"Delete"**
3. Confirm deletion by clicking "**Yes**".
4. Click "Save".



5.3 ALTERNATIVE MILESTONES

Milestones are key dates that are tracked for an investment and primarily apply to Projects. Once an investment plan is approved, these establish the **baseline for ACER tracking**. Refer to the Project Development Category guideline on the IM SharePoint site to determine which Milestones are required and ensure they are rational in relation to the BCS Approval Date (EMPP Date) and In-Service Date. **At a minimum, BCS Approval Date and In-Service date are required for all Projects.**

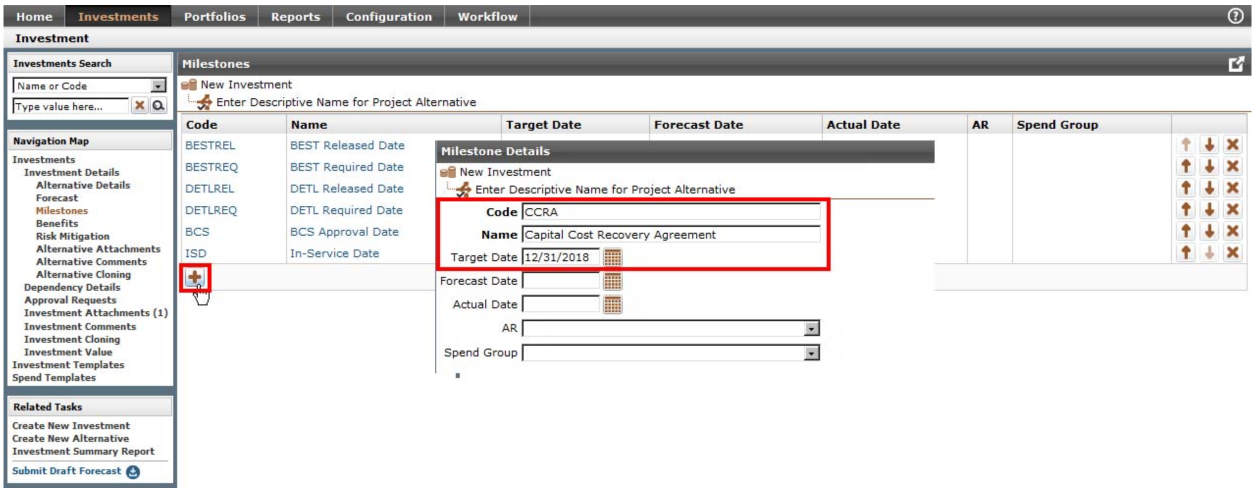
Milestone (Name)	Code	Description	Field to populate	Shifts with Start Date?
Capital Cost Recovery Agreement	CCRA	Date agreed to in the CCRA. Note that, this date does **not** shift	Target Date	No
BEST Released Date	BESTREL	Budgetary Estimate Released Date. Refers to the date the Planner intends on releasing funds to the Service Provider to complete a Budgetary Estimate.	Forecast Date	Yes
BEST Required Date	BESTREQ	Budgetary Estimate Required Date. Refers to the date the Planner requires the Service Provider to complete the Budgetary Estimate by.	Forecast Date	Yes
DETL Released Date	DETLREL	Detailed Estimate Released Date. Refers to the date the Planner intends on releasing funds to the Service Provider to complete a Detailed Estimate.	Forecast Date	Yes
DETL Required Date	DETLREQ	Detailed Estimate Required Date. Refers to the date the Planner requires the Service Provider to complete the Detailed Estimate by.	Forecast Date	Yes
BCS Approval Date	BCS	Business Case Approval Date. Refers to the date you expect full Business Case Approval (EMPP) and full release of funds to the Service Provider. Ensure it is rational based on how long estimating will take as well as the approval process (OAR)	Forecast Date	Yes
In-Service Date	ISD	Refer to the date you expect the asset(s) to go in-service If multiple I/S date are expected, enter the latest date	Forecast Date	Yes

Important Reminder:

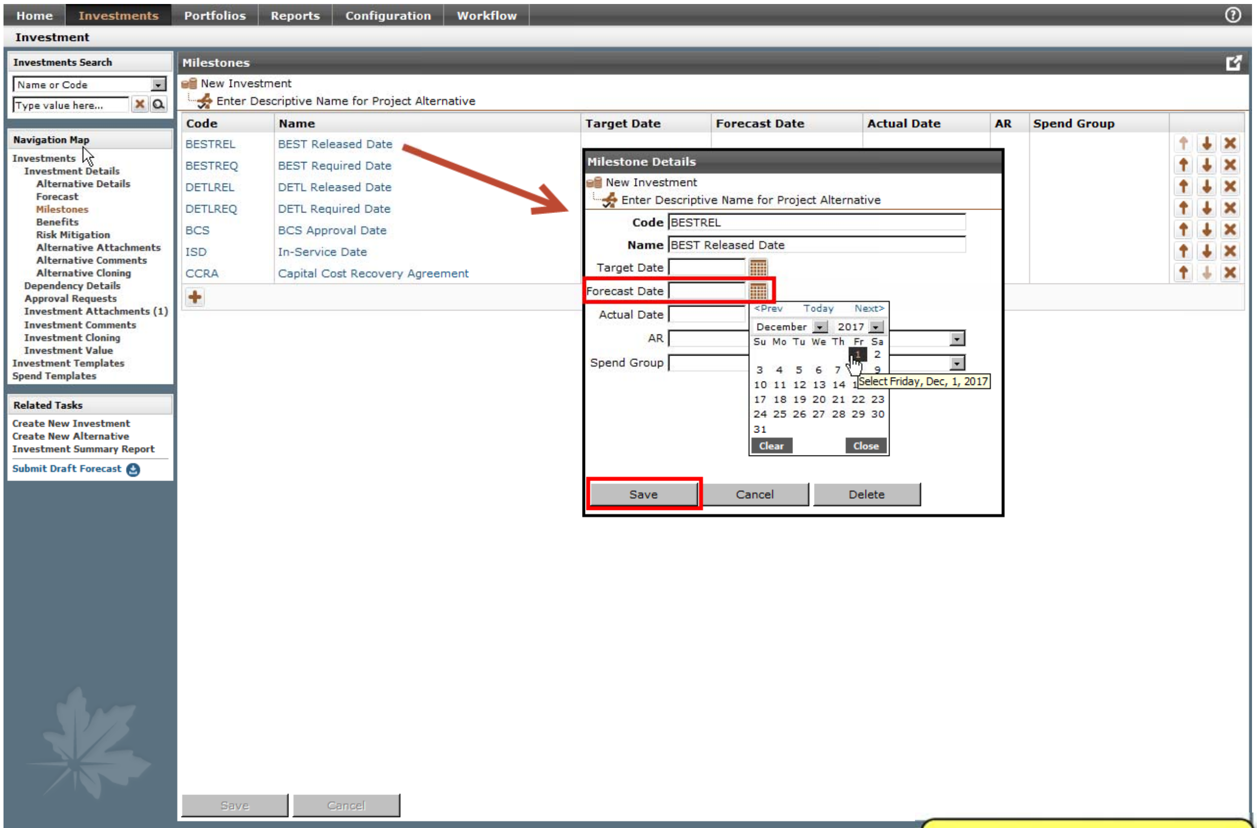
- All Milestone Dates **shift** with the Alternative Start Date with the exception of CCRA Date
- Do not select an AR for any Milestone
- If there are Multiple ISD's, enter the last one one only

5.3.1 CREATE/MODIFY MILESTONES

1. From within an existing Investment, select **<Milestones>.** This will take you to the <Milestone> page of the **Recommended Alternative** where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative.
2. To **create** a new Milestone, click on the button and populate it based on the Name, Code and "Field to populate" as specified in the guideline above (note that, if an investment is created from a template, most milestones should already exists)



3. To **modify** an existing Milestone, click on the Milestone **Code** or **Name**
4. Click on the button and select the correct date
5. Click **"Save".**


Home
Investments
Portfolios
Reports
Configuration
Workflow
Investment
Milestones
New Investment
Enter Descriptive Name for Project Alternative
Code
Name
Target Date
Forecast Date
Actual Date
AR
Spend Group
BESTREL BEST Released Date
BESTREQ BEST Required Date
DETLREL DETL Released Date
DETLREQ DETL Required Date
BCS BCS Approval Date
ISD In-Service Date
CCRA Capital Cost Recovery Agreement
Milestone Details
Code BESTREL
Name BEST Released Date
Target Date
Forecast Date
Actual Date
AR
Spend Group
Select Friday, Dec, 1, 2017
Save
Cancel
Delete


Milestones
New Investment
Enter Descriptive Name for Project Alternative
Should always be blank
Code
Name
Target Date
Forecast Date
Actual Date
AR
Spend Group
BESTREL BEST Released Date 12/01/2017
BESTREQ BEST Required Date
DETLREL DETL Released Date
DETLREQ DETL Required Date
BCS BCS Approval Date
ISD In-Service Date
CCRA Capital Cost Recovery Agreement 12/31/2018
Should only be used for CCRA

5.4 MODULE 3 - EXERCISE 2

Please refer to handout.

5.5 ALTERNATIVE RISK MITIGATION

Risk Mitigation is used evaluate and document the **Baseline risk** of your investment (risk of doing nothing), as well as **Residual risk** of each alternative **(**risk that remains if alternative is selected). In AIP, a risk assessment is completed for each corporate value (e.g. Reliability, Customer, Shareholder, Environment, Safety, Employee, Productivity, etc.) that applies to your alternative(s).

Listed below is an example of common Alternatives Levels:

Alternative Level	Description
Asset Optimal	The ideal balance point where total lifecycle cost is minimized and risk is low and in line with the corporate strategy (e.g. 4^{th} quartile Dx reliability)
Intermediate	Residual is somewhere in the middle of Vulnerable and Optimal (e.g. keep the lights on + ensure reliability for critical customers only)
Vulnerable	Residual risk in close to “red zone”, addresses only the bare minimum to “keep lights on” without leaving Hydro One in the “red zone” (e.g. corrective, regulatory, safety). Not sustainable over a long period of time.

The Risk Assessments provided will be used by AIP’s optimization module to propose which investments/alternative levels are put forward for inclusion in the Investment Plan.

<u>High-level steps to follow when evaluating risk:</u>

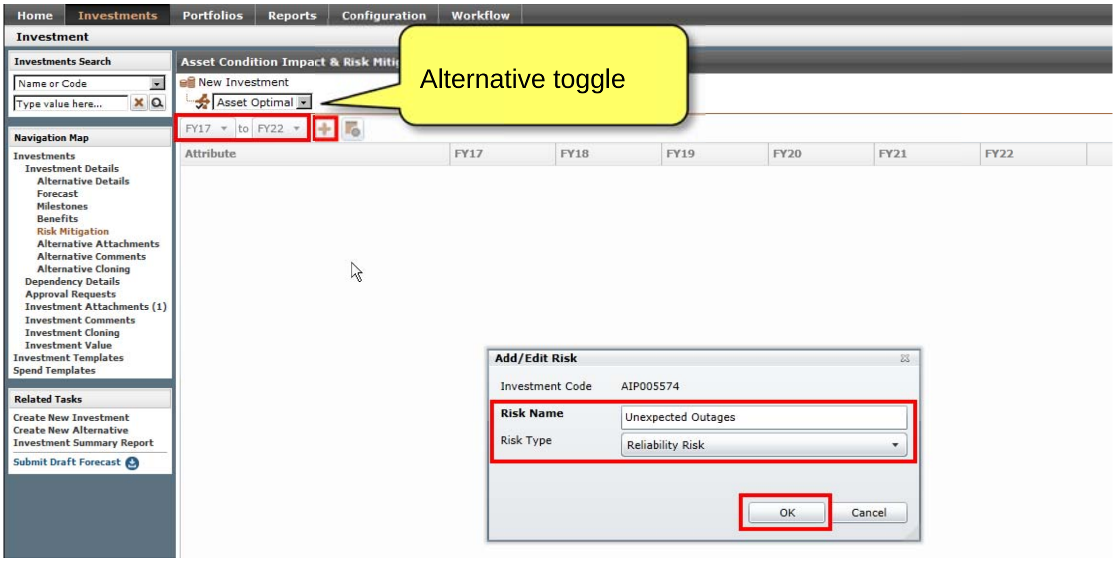
1. Identify the Corporate values that apply to your investment/alternative
2. Assess the Consequence and Probability of each applicable Corporate Value (consult the risk consequence table, call upon historical data, consult with your peers and manager) in AIP
3. Document the rationale behind your Probability/Consequence selection

5.5.1 Assign Baseline Risk

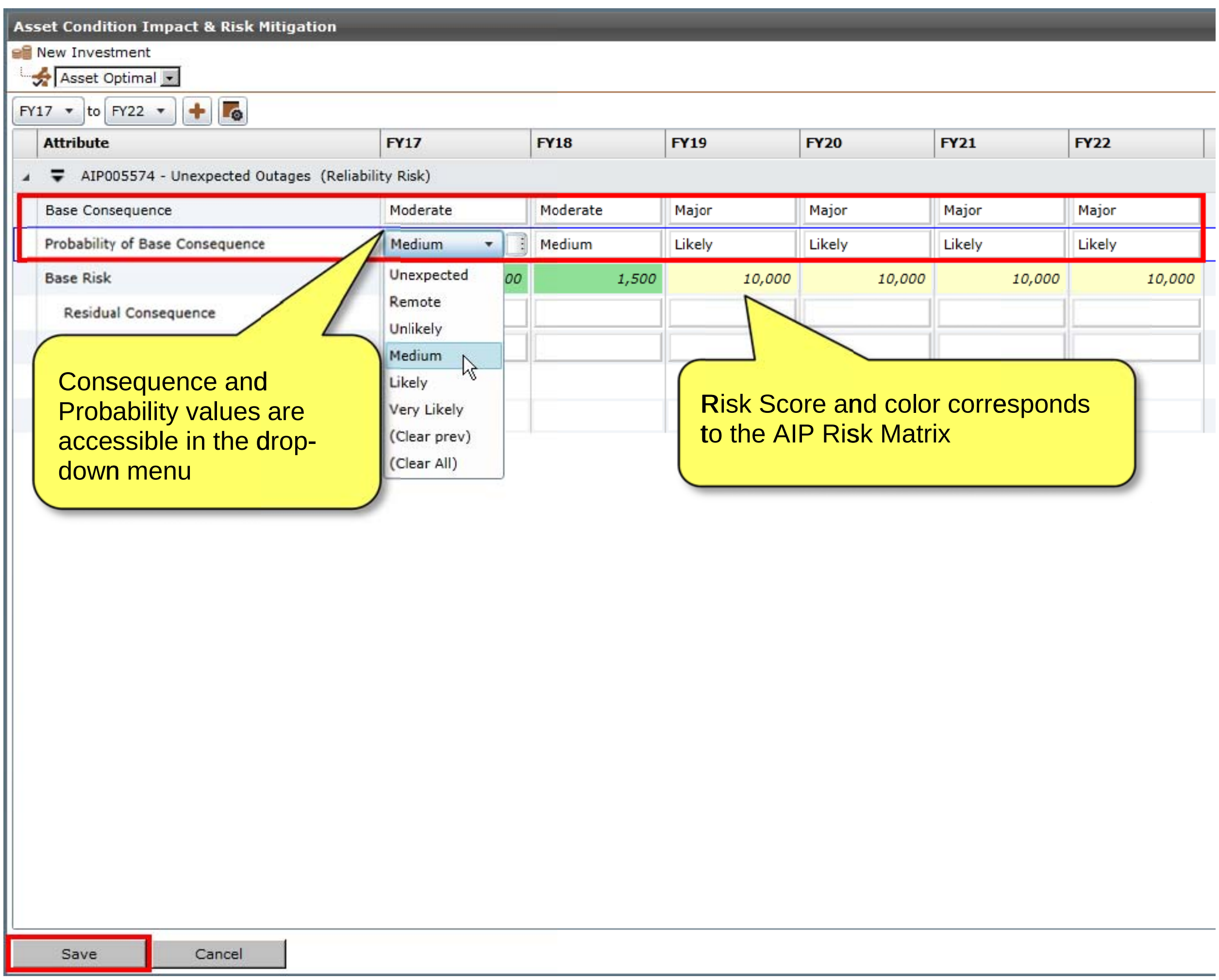
Baseline Risk is used to capture the Risk of doing nothing. It can be entered in any Alternative and only needs to be entered once, per investment.

<u>Instructions</u>

1. From within an existing Investment, select **<Risk Mitigation>.** This will take you to the <Risk Mitigation> page of the **Recommended Alternative** where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Modify the **Years** to reflect the current planning window (e.g. 2017 – 2022)
3. Click the button to add a Corporate Value
4. Choose the **Risk Type** (Corporate Value) and assign a **Risk Name**
5. Click **Ok**



6. Indicate the **Base Consequence** for each year, in the "**Base Consequence**" row and the associated **Probability** in the "**Probability of Base Consequence"** row from the drop-down menu (note that, the tool automatically inputs the same consequence / probability for each future year unless otherwise specified)
7. Click **"Save".**
8. Repeat steps above to assign Baseline Risk to each Corporate Value that applies to your investment.
9. Note that, Baseline risk justification for each Corporate Value will be entered on the main **Investment Details** page.

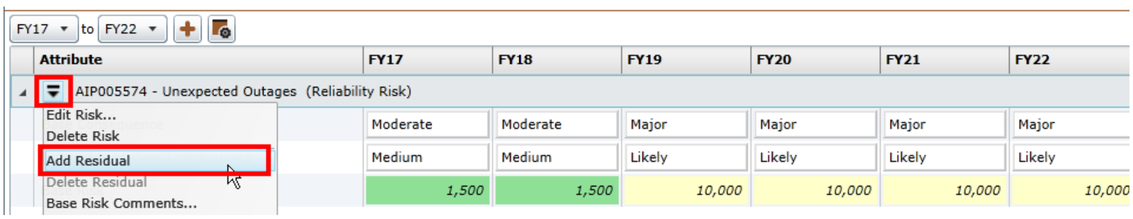


5.5.2 ASSIGN RESIDUAL RISK FOR EACH ALTERNATIVE

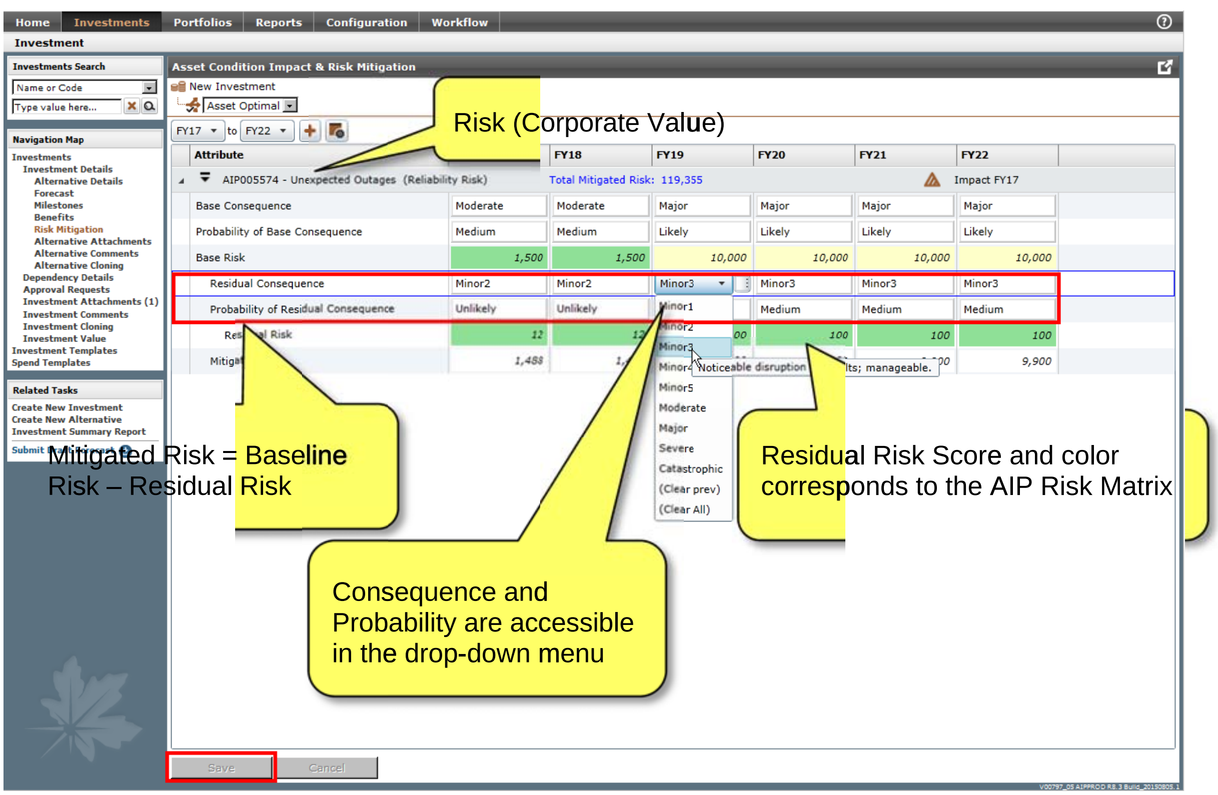
Residual Risk is assessed for each Risk (Corporate Value) that applies your to Alternative(s). The assumption is that residual risk will decrease as the funding level increases (e.g. from Vulnerable to Optimal). **The expectation is that no proposed Alternative will leave Hydro One in the "red zone".**

Instructions

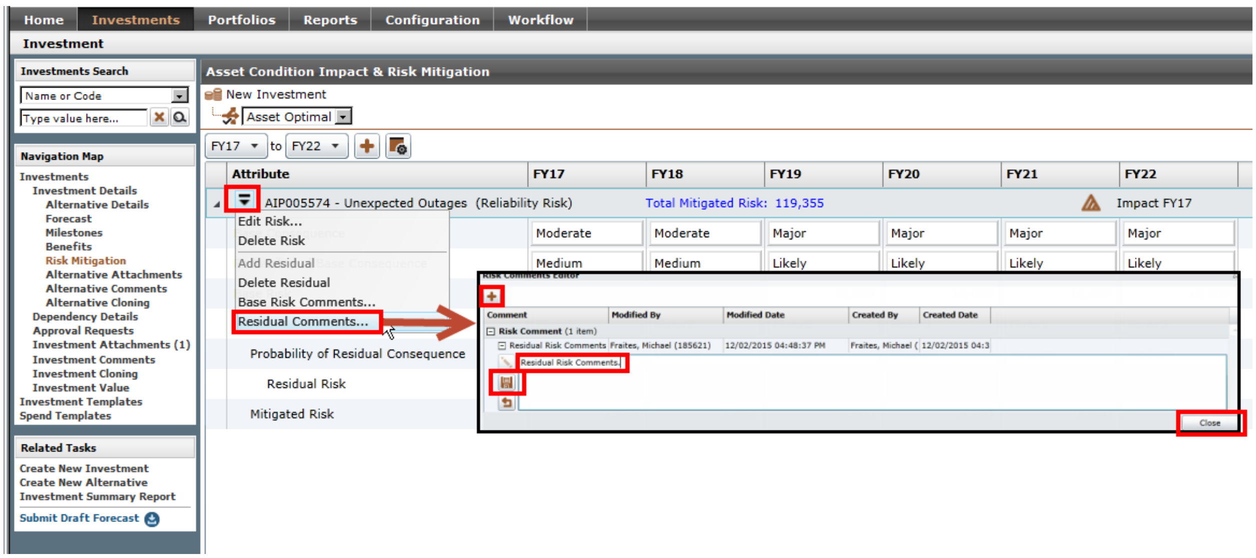
1. From withinan existing Investment, select **<Risk Mitigation>.** This will take you to the <Risk Mitigation> page of the **Recommended Alternative** where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Modify the **Years** to reflect the current planning window (e.g. 2017 – 2022).
3. Select the **Risk** (Corporate Value) that you will be assessing the Residual Risk for. **If the Residual Risk rows do not appear, please follow the steps below.**
   a) Click on the button that corresponds to the Risk you want to add Residual Risk for.
   b) Select "Add Residual…"



4. Indicate the **Residual Consequence** for each year, in the "**Residual Consequence**" row and the associated **Probability** in the "**Probability of Residual Consequence"** row (note that, the tool automatically inputs the same consequence / probability for each future year unless otherwise specified).
5. Click "**Save"**



6. **Residual Risk justification** should be captured in the **Comments** of each Risk. These comments should clearly explain how you arrived at the Probability and Consequence for each Risk in each Alternative.
   a) Click on the button
   b) Select "Residual Comments…"
   c) Click on the button
   d) Enter your justification
   e) Click the button
   f) Click Close.



7. Click "**Save**"
8. Repeat steps above to assign Residual Risk to each Corporate Value that applies to each alternative.

5.6 ALTERNATIVE FINANCIAL BENEFITS

In some cases, an investment is undertaken on the basis of the benefits that will be realized as opposed to risk that will be mitigated (e.g. ISD initiatives). However, it is also possible for an investment to be both risk driven and benefit driven. There are two types of financial benefits to consider.

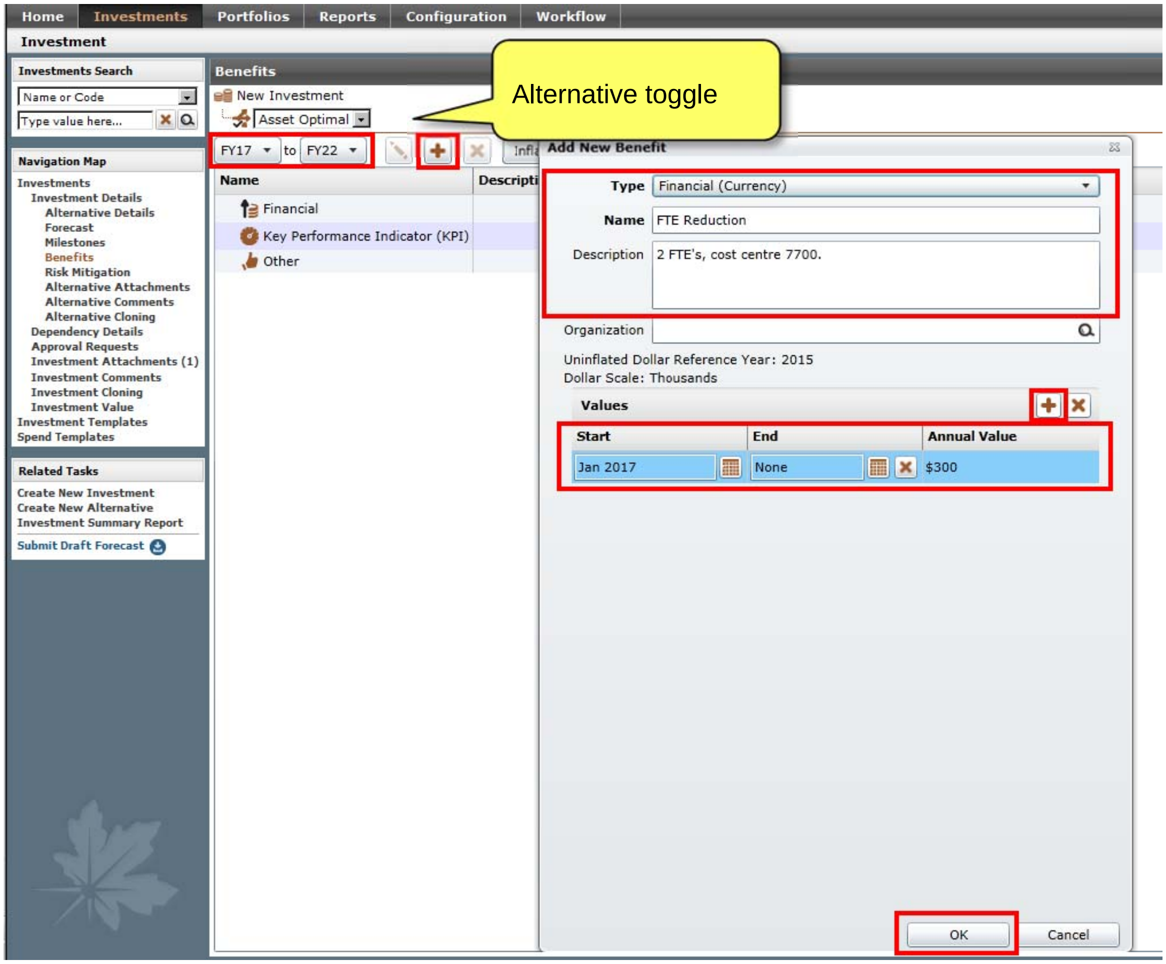
- Cost Savings
  - FTEreduction
  - Investment deferral/cancellation (e.g. by implementing system X, you no longer need to maintain system Y)
- Cost Avoidance (e.g. by installing one asset that replaces two assets, you reduce the future maintenance costs)

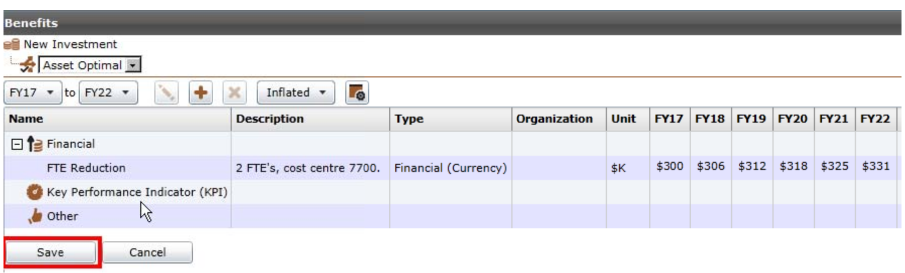
The Financial Benefits provided will be used by AIP's optimization module to decide what investments/alternative levels are selected.

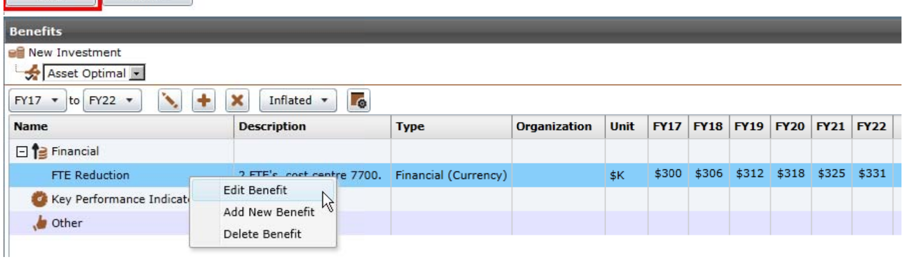
5.6.1 INPUT NEW FINANCIAL BENEFIT

<u>Instructions</u>

1. From within an existing Investment, select **<Benefits>.** This will take you to the <Benefit> page of the **Recommended Alternative** where you can make modifications. Note that, you change the Alternative by clicking on drop-down menu under the investment name, and selecting a different alternative below.
2. Modify the **Years** to reflect the current planning window (e.g. 2017 – 2022)
3. Click the button to **Add New Benefit**
   a) For **Type**, specify "Financial (Currency)"
   b) Enter a **Name** for the benefit (e.g. FTE Reduction)
   c) Describe the benefit in the **Description** field (e.g. number of FTE's saved or investment that is being discontinued)
4. From within the New Benefit screen click button under "Values" to **assign the Values**
   a) Enter the date the benefit will start in the "**Start**" field by clicking on the button and selecting a date
   b) Enter the date the benefit will end by clicking on the button and selecting a date in the "**End**" field. If the benefit will realized indefinitely, leave it as "None"
   c) Enter the financial benefit that will be realized (uninflated dollars) in the "**Annual Value"** field. Ensure to take note of the Dollar Scale. **General rule of thumb is $150K per FTE.**
   d) Click **Ok.**
5. Click**Save.**
6. Repeatthe above steps for each alternative that has a Financial Benefit.
7. To**modify** an existing Financial Benefit, right click on the Financial Benefit name, select "**Edit Benefit**" and follow the steps outlined above.







Important Reminder

The only benefit type that will be considered in optimization is “Financial (Currency)”. Ensure that no other Benefit Type is specified.

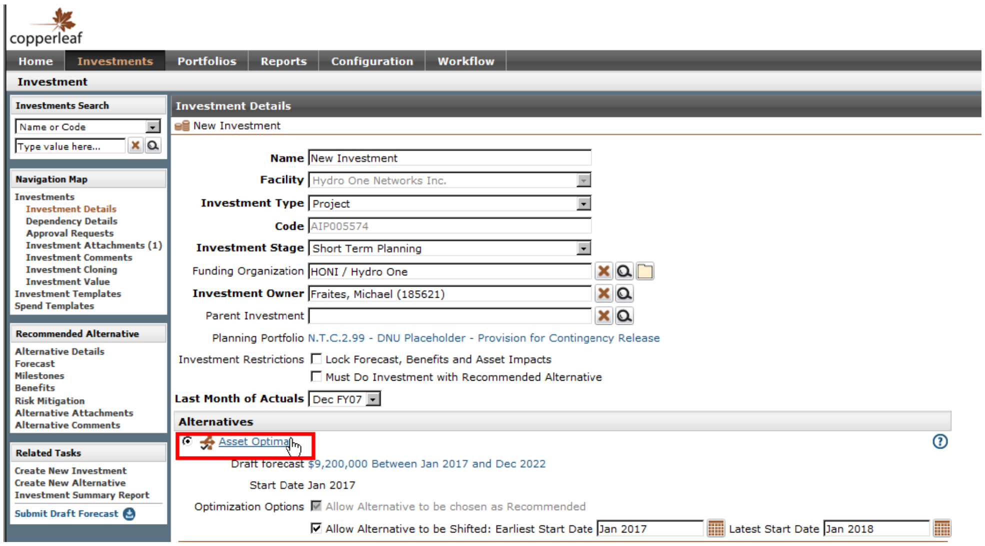
Benefits are to be entered in uninflated dollars – AIP will apply the appropriate inflation rate for future years.

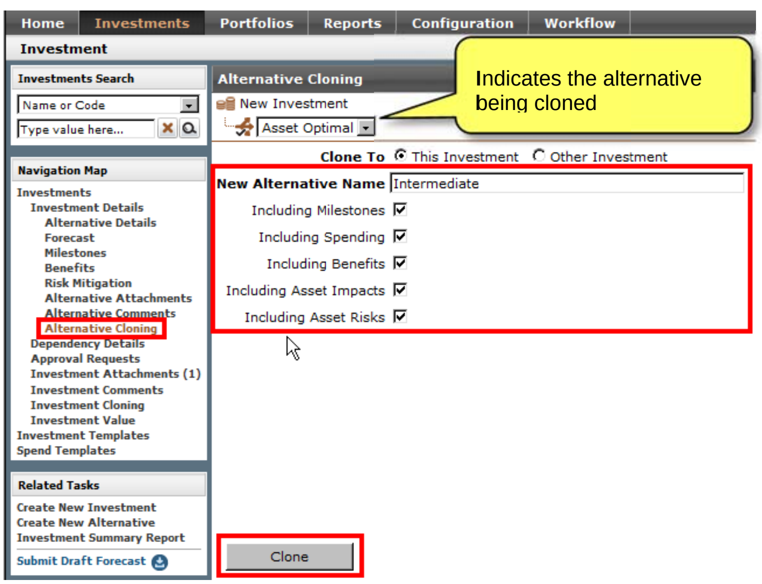
Rule of thumb is $150K per FTE

5.7 CLONE AN ALTERNATIVE

In some cases, you may wish to clone an existing alternative as opposed to creating a new one from scratch.

1. From within an existing Investment, click on the **Alternative** you wish clone.
2. In the left hand menu, select <**Alternative Cloning**>
3. Specify the alternative elements you wish to clone and assign it a new name
4. Click “Clone”
5. Edit the Alternatives details as required.



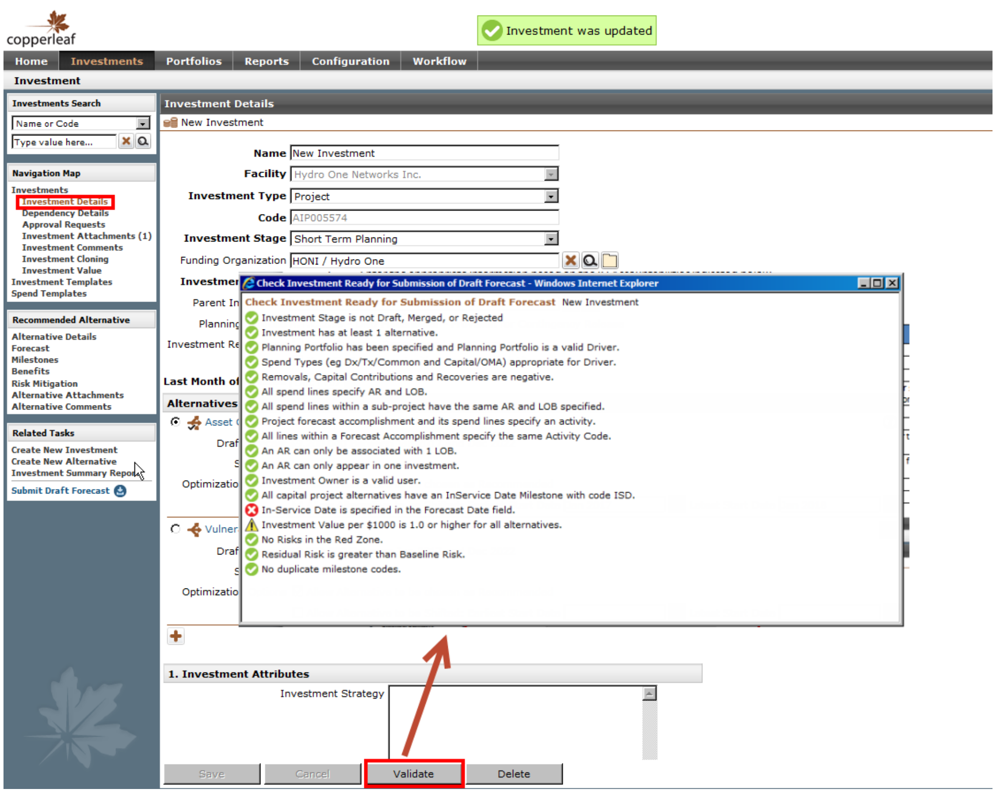


5.8 INVESTMENT VALIDATION

Before your investment can be Submitted or routed through workflow for approval, AIP will perform system validations which verifies the investment inputs against a set of a business rules. Validations will differ depending on characteristics of the investment (e.g. Project or Program, Capital or OMA, etc.) If validation criteria are not met, a red circle will appear informing you of the violation. If this occurs, you will need to address the validations errors and re-validate your investment.

Instructions

1. From within the **Investment Details** section of an Investment, click "**Save**". This will ensure all recent modifications are considered as part of validation.
2. Click on the **Validate** button
3. A pop-up will appear informing you of the Success, Failure or Warning (note that, you can still proceed with a warning) of each validation performed for the investment
4. If there are validations failures, correct the issue(s), save the investment and re-validate.
5. If validation is successful, you may proceed with routing your investment for workflow approval.

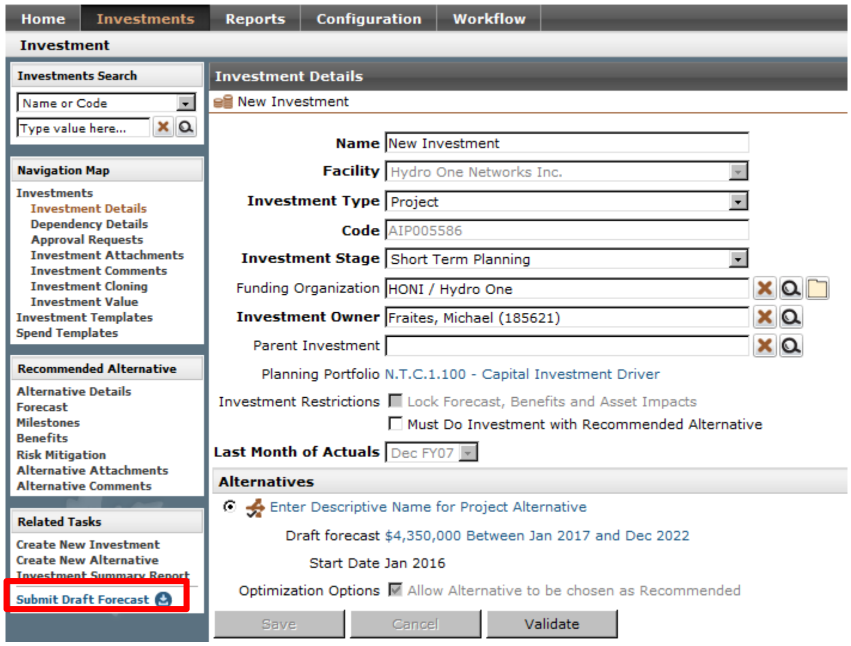


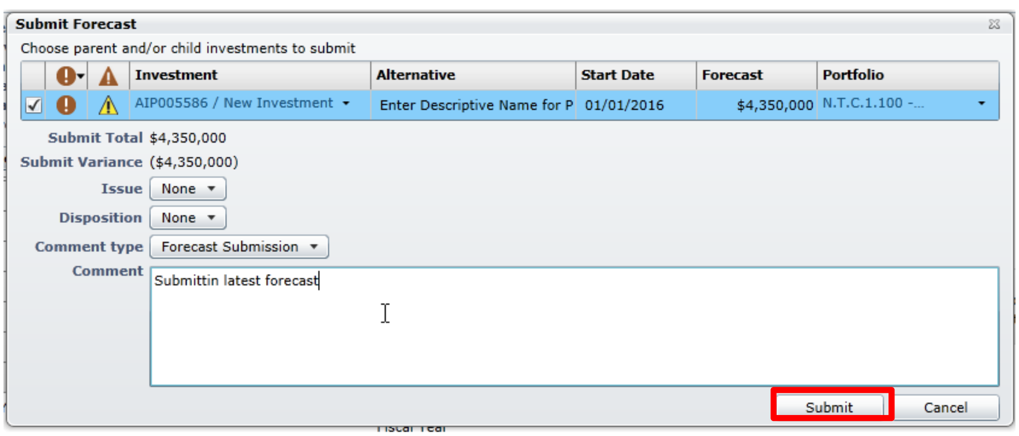
5.9 SUBMIT DRAFT FORECAST

Once your investment has been validated, you may “Submit Draft Forecast”. Although the Draft Forecast is automatically submitted during workflow approval, it is a good habit to submit the draft forecast anytime you have changed your Forecast (cash flows or accomplishment units). This will ensure that if a draft accomplishment file is run, your latest changes are reflected.

<u>Instructions</u>

1. Fromwithin the **Investment Details** section of an Investment, click “**Submit Draft Forecast**” under the sub-menu “**Related Tasks”.**
2. Enterany relevant comments click the **Submit** button





5.10 MODULE 3: EXERCISE 3

Please refer to handout.

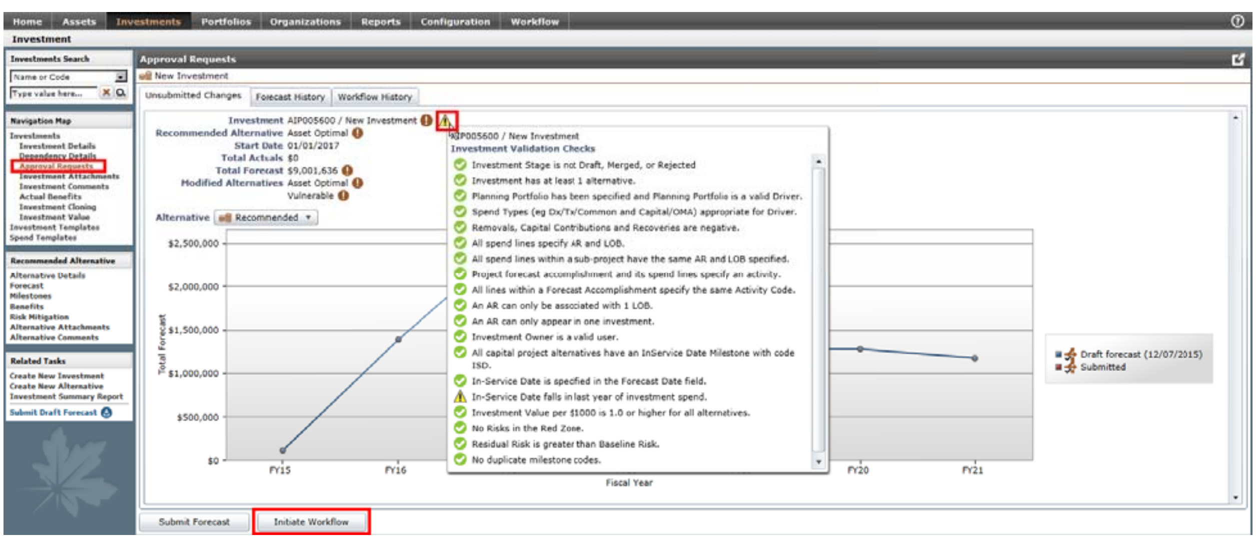
6 MODULE 4: SUBMITTING INVESTMENTS FOR WORKFLOW APPROVAL

In order for an investment to be proposed as part of in the Investment Plan, it must be approved by the appropriate level of management via AIP Workflow. The following diagram provides an overview of the approval process and dollar thresholds.

6.1.1 SUBMIT YOUR INVESTMENT THROUGH WORKFLOW

Instructions

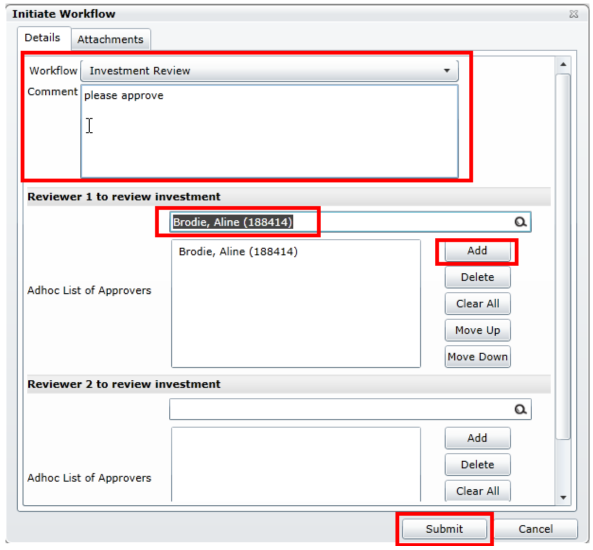
1. From within the **Investment Details** section of an Investment, click **"Approval Requests"**.
2. Next to the investment code/name you will see a Success, Failure or Warning icon that represents the validation outcome. Hovering over the icon will present you with the result of each validation. As mentioned in the section above, you will not be able submit your investment through workflow if your investment has a Failure icon.
3. Click on the "**Initiate Workflow"** button at the bottom of the page



4. Under the "**Workflow"** drop-down select **"Investment Review"**
5. Enter a **Comment** that you want the reviewer(s)/approver(s) to see (e.g. please approve, changes made as requested, etc.)
6. Specify **Reviewer 1** or **Reviewer 2** if required
   a) Enter any part of the reviewers name in the relevant review box
   b) Click the button
   c) Select the **Reviewer** that matches your entry in Step A

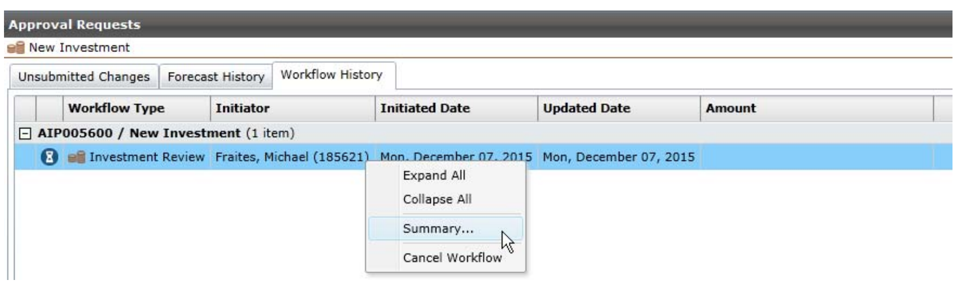
d) Click the **Add** button to add the reviewer to the “Adhoc List of Approvers” list (note that, you can have multiple reviewers)

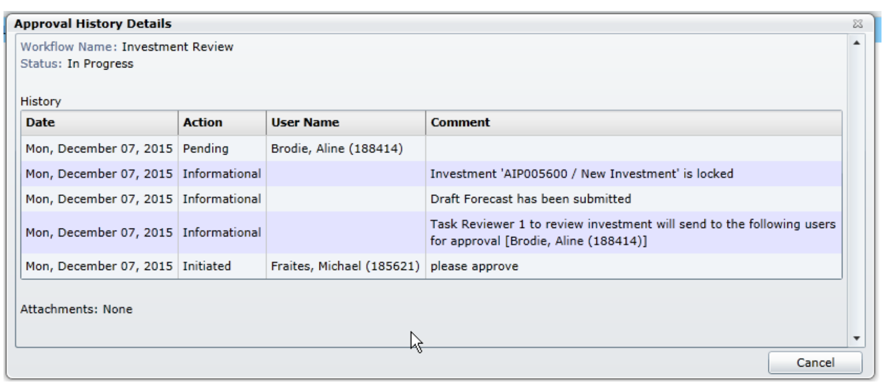
7. Click“**Submit”.**



8. Once the investment has successfully been submitted through workflow, the **Workflow History** screen will appear (note that, this may take up to 30 seconds to appear)

9. To view a summary of the workflow, right click on the workflow and select “**Summary…”**





Important Reminder:

Once an investment is submitted through workflow it will be locked until either condition is met:

a) it is rejected by the reviewer or b) the next planning cycle has begun.

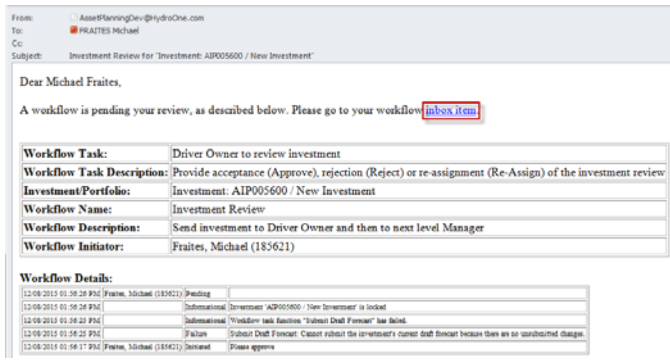
Reviewers only need to be entered if you require someone **other** than the Driver Owner/Director to review your investment. By default, AIP will route the investment to the Driver Owner if no Reviewer is specified.

6.1.2 RESPOND TO A WORKFLOW ITEM ASSIGNED TO YOU

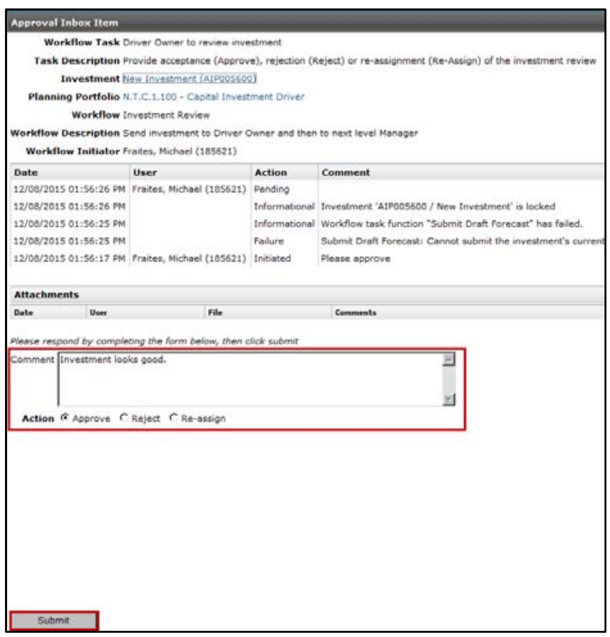
Once an investment has been submitted by the Investment Owner and e-mail notification will be sent to the next responder in the approval chain (e.g. Reviewer, Driver Owner or Director) notifying them that an investment is ready for their review. The responder will need to action it by; rejecting it, approving it, or re-assigning it.

<u>Instructions</u>

1. Navigate to the investment by clicking on the link in the work notification email

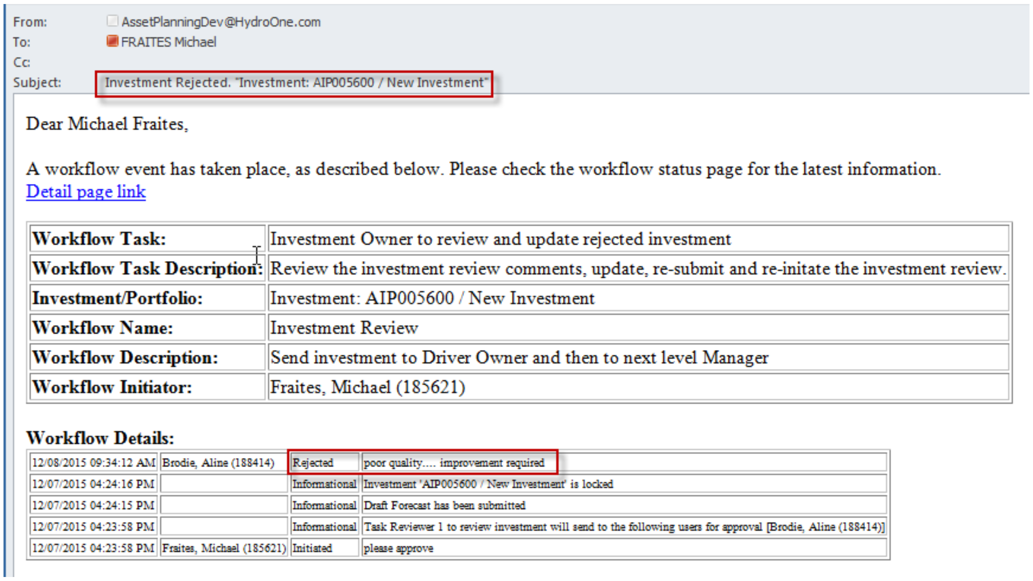


2. Choose one of the following Options: **Approve, Reject, Re-Assign**
3. Enter any relevant comments and click “**Submit**”



6.1.3 WORKFLOW EMAIL – "INVESTMENT REJECTED"

If an investment has been rejected by **any** responder in the approval chain, an email notification will be sent to Workflow Initiator (typically this would be the Investment Owner) informing them of the result, along with any comments provided by the responder. In this case, the Investment Owner must address the issues and re-submit the investment for approval. Note that, if the last responder in the approval chain rejects the investment, it will need to go through the entire approval chain once it's re-submitted.



From: AssetPlanningDev@HydroOne.com
To: FRAITES Michael
Cc:
Subject: Investment Rejected. "Investment: AIP005600 / New Investment"

Dear Michael Fraites,

A workflow event has taken place, as described below. Please check the workflow status page for the latest information.
Detail page link

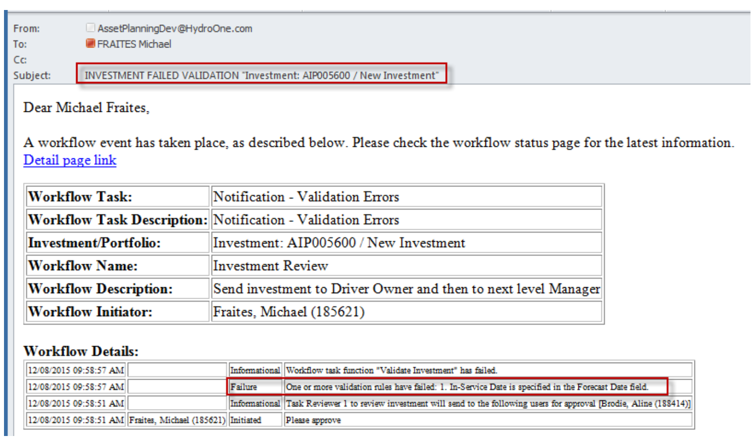
Workflow Task:	Investment Owner to review and update rejected investment
Workflow Task Description:	Review the investment review comments, update, re-submit and re-initate the investment review.
Investment/Portfolio:	Investment: AIP005600 / New Investment
Workflow Name:	Investment Review
Workflow Description:	Send investment to Driver Owner and then to next level Manager
Workflow Initiator:	Fraites, Michael (185621)

Workflow Details:

12/08/2015 09:34:12 AM	Brodie, Aline (188414)	Rejected	poor quality.... improvement required
12/07/2015 04:24:16 PM		Informational	Investment 'AIP005600 / New Investment' is locked
12/07/2015 04:24:15 PM		Informational	Draft Forecast has been submitted
12/07/2015 04:23:58 PM		Informational	Task Reviewer 1 to review investment will send to the following users for approval [Brodie, Aline (188414)]
12/07/2015 04:23:58 PM	Fraites, Michael (185621)	Initiated	please approve

6.1.4 WORKFLOW EMAIL – "INVESTMENT FAILED VALIDATION"

If an investment has been submitted for approval but did not pass validation, an email notification will sent to the Investment Owner informing them of the result. In this case, the Investment Owner must address the validation error and re-submit the investment for approval.



From: AssetPlanningDev@HydroOne.com
To: FRAITES Michael
Cc:
Subject: INVESTMENT FAILED VALIDATION "Investment: AIP005600 / New Investment"

Dear Michael Fraites,

A workflow event has taken place, as described below. Please check the workflow status page for the latest information.
Detail page link

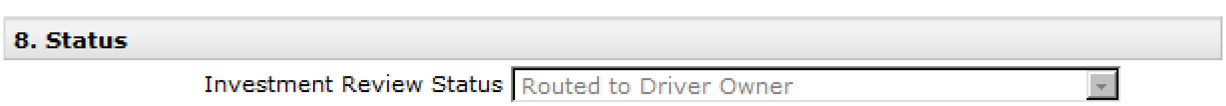
Workflow Task:	Notification - Validation Errors
Workflow Task Description:	Notification - Validation Errors
Investment/Portfolio:	Investment: AIP005600 / New Investment
Workflow Name:	Investment Review
Workflow Description:	Send investment to Driver Owner and then to next level Manager
Workflow Initiator:	Fraites, Michael (185621)

Workflow Details:

12/08/2015 09:58:57 AM		Informational	Workflow task function "Validate Investment" has failed.
12/08/2015 09:58:57 AM		Failure	One or more validation rules have failed: 1. In-Service Date is specified in the Forecast Date field.
12/08/2015 09:58:51 AM		Informational	Task Reviewer 1 to review investment will send to the following users for approval [Brodie, Aline (188414)]
12/08/2015 09:58:51 AM	Fraites, Michael (185621)	Initiated	Please approve

6.1.5 VIEW WORKFLOW STATUS

The status of your workflow can be viewed at any time from the main investment details under the field "Investment Review Status".



6.2 MODULE 4 – EXERCISE 4

Please refer to handout.

7 ADVANCED TOPICS

7.1 INVESTMENT DEPENDENCIES

Investment dependencies allow an Investment Owner to specify Alternative Dependencies between two investments (e.g. Wood Pole Inspection Program and Wood Pole Replacement must have the same Alternative Level selected) and Start Date offsets (e.g. If Project 1 is has a start date of Jan 1, 2017 and Project 2 can only start one year after Project 1, you can input a dependency such that, if the Optimizers shifts one of the projects, the other shifts by the same amount of time)

Please contact the AIP Team for assistance in setting up dependencies.

8 FREQUENTLY ASKED QUESTIONS

8.1 WHY CAN'T I SELECT MY AR?

Answer: AR numbers are not synched with SAP-IM and therefore need to be updated by the AIP Team on a periodic basis. If you're AR is not available please contact the AIP Team.

8.2 WHY ISN'T MY ASSET TYPE AVAILBLE?

Answer: Asset Types need to be provided to the AIP Team by the Planner/Manager so that they can be loaded into AIP. If an Asset Type is missing please contact the AIP Team and provide the following information:

Asset Type Code
Asset Type Name
Asset Type Voltage Levels

8.3 WHY IS MY INVESTMENT LOCKED?

Answer: Your investment may be locked for two reasons:

1 – Investment is in the executing stage. Investments in this stage are managed by the AIP Team (the AIP Team loads a multi-year forecast provided by the LOB on a quarterly basis)

2 – Investment has been submitted through workflow. Once an investment has been submitted through workflow it remains locked until one of the following conditions have been met:

- Workflow is rejected by workflow responder
- New investment planning cycle has begun

8.4 HOW CAN I CHANGE THE PLANNING PORTFOLIO (DRIVER) OF AN INVESTMENT?

Answer: Once the Planning Portfolio (driver) has been set by the IO, it can only be changed by the AIP Team. If a driver change is required, please contact the AIP Team. Note that, the driver in AIP and SAP must match.

8.5 HOW CAN I DELETE AN INVESTMENT

Answer: Investment Owners cannot delete investments. If an alternative is an investment is no longer required, please add the prefix "X – Completed/Discontinued – " to the investment name.

8.6 HOW CAN I DELETE AN ALTERNATIVE

Answer: Investment Owners cannot delete alternatives. If an alternative is no longer required, please contact the AIP Team to delete it on your behalf.

8.7 WHAT ARE SCENARIOS (E.G. DRAFT, SUBMITTED, APPROVED)

Answer:

Draft: The most recent forecast that have been entered / saved by the Investment Owner, may not necessarily be accurate or appropriate for review

Submitted: Signifies the latest Draft Forecast that was submitted with the intention of being “visible” to others. The Accomplishment File references the Submitted Forecast.

Approved: This number should match the $’s in the latest Approved Accomplishment File

8.8 WHAT DOES THIS VALIDATION ERROR MEAN?

Answer: There are various validation errors that occur and are dependent on the investment type or other factors. If you an unsure of how to rectify a validation error please contact the AIP Team.

9 APPENDICIES

9.1 APPENDIX A – FORECAST SETUP EXAMPLES

9.1.1 PROGRAM ALTERNATIVE – TYPE A FORECAST ACCOMPLISHMENTS (MULTIPLE AR'S)

Forecast

DS Preventive Maintenance - Ground and Sites

Asset Optimal

FY16 to FY20 (5 Years) Filter No Filter Inflated Inflated $K

	Account	Activity	AR	Organization	Unit	Investment Total	FY16	FY17	FY18	FY19	FY20
Draft forecast without actuals											
1 DS Preventive Maintenance - Planned - Ground &Site											
DS Preventive Maintenance - Planned - Ground &Site			20145 /	206 / STATIONS		26,088.00	3,683.00	3,683.00	3,683.00	3,683.00	3,683.00
1.1 DS Preventive Maintenance - Planned - Ground &Site	DXOMA / Dx ON		20145 /	206 / STATIONS	$K	$12,546	$1,674	$1,713	$1,747	$1,782	$1,817
2 DS Preventative Maintenance - Herbicide Application											
Forecast Accomplishment			23577 /	204 / FORESTRY		13,770.00	2,295.00	2,295.00	2,295.00	2,295.00	2,295.00
2.1 DS Herbicide Application	DXOMA / Dx ON		23577 /	204 / FORESTRY	$K	$4,528	$734	$751	$766	$781	$797

9.1.2 PROGRAM ALTERNATIVE – TYPE B FORECAST ACCOMPLISHMENTS

Illustrative only – no programs currently exist with this setup

Pole Replacement

Vulnerable - Multiple Units

FY15 to FY19 (5 Years) Filter No Filter Uninflated (Draft Only) Uninflated $K

	Account	Activity	AR	Organizatic	Unit	Investment Total	FY15	FY16	FY17	FY18	FY19
Draft forecast without actuals											
1 Rural Wood Pole In Earth											
Rural Wood Pole In Earth		PLWD - IE / Rural Wood Pole In Earth	17353 / End	205 / LINES		48,400.00	6,600.00	6,200.00	7,200.00	8,200.00	9,200.00
1.1 End of Life Replacement of Wood Pc	DXCAP / Dx Capital	PLWD - IE / Rural Wood Pole In Earth	17353 / End	205 / LINES	$K	$312,999	$38,369	$36,044	$41,857	$47,671	$53,484
Dx Removals	DXREM / Dx Removals	PLWD - IE / Rural Wood Pole In Earth	17353 / End	205 / LINES	$K	($37,560)	($4,604)	($4,325)	($5,023)	($5,720)	($6,418)
2 Rural Wood Pole in Rock											
Rural Wood Pole in Rock		PLWD - IR / Rural Wood Pole in Rock	17353 / End	205 / LINES		16,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00
2.1 End of Life Replacement of Wood Pc	DXCAP / Dx Capital	PLWD - IR / Rural Wood Pole in Rock	17353 / End	205 / LINES	$K	$134,780	$7,841	$7,841	$7,841	$7,841	$7,841
Dx Removals	DXREM / Dx Removals	PLWD - IR / Rural Wood Pole in Rock	17353 / End	205 / LINES	$K	($16,174)	($941)	($941)	($941)	($941)	($941)
3 LV Wood Pole In Earth											
LV Wood Pole In Earth		PLWD - LVIE / LV Wood Pole In Earth	17353 / End	205 / LINES		21,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
3.1 End of Life Replacement of Wood Pc	DXCAP / Dx Capital	PLWD - LVIE / LV Wood Pole In Earth	17353 / End	205 / LINES	$K	$187,958	$18,477	$18,477	$18,477	$18,477	$18,477
Dx Removals	DXREM / Dx Removals	PLWD - LVIE / LV Wood Pole In Earth	17353 / End	205 / LINES	$K	($22,555)	($2,217)	($2,217)	($2,217)	($2,217)	($2,217)
4 LV Wood Pole In Rock											
LV Wood Pole In Rock		PLWD - LVIR / LV Wood Pole In Rock	17353 / End	205 / LINES		21,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
4.1 End of Life Replacement of Wood Pc	DXCAP / Dx Capital	PLWD - LVIR / LV Wood Pole In Rock	17353 / End	205 / LINES	$K	$214,213	$23,728	$23,728	$23,728	$23,728	$23,728
Dx Removals	DXREM / Dx Removals	PLWD - LVIR / LV Wood Pole In Rock	17353 / End	205 / LINES	$K	($25,706)	($2,847)	($2,847)	($2,847)	($2,847)	($2,847)

9.1.3 PROJECT ALTERNATIVES – NO FORECAST ACCOMPLISHMENTS

Forecast

Nelson TS Recofiguration-Replace T1/T2 DESN with new DESN

Alternative 1

FY16 to FY20 (5 Years) Filter No Filter Inflated Inflated $K

	Account	Activity	AR	Organization	Unit	Investme	FY16	FY17	FY18	FY19	FY20
Draft forecast without actuals											
1 Nelson TS T1/T2/T3/T4 Station Refurbis											
1.1 Nelson TS T1/T2/T3/T4 Station Refu	TXCAP / Tx Capital		20584 / London Nelson TS EOL Replace	203 / ENG & PROJ D	$K	$39,350	$3,250	$9,150	$19,000	$7,950	
1.2 Nelson TS T1/T2/T3/T4 Station Refu	TXCON / Tx Capital Contribution		20584 / London Nelson TS EOL Replace	203 / ENG & PROJ D	$K	($8,300)	($3,350)	($1,750)	($1,750)	($1,450)	
1.3 Nelson TS T1/T2/T3/T4 Station Refu	TXREM / Tx Removals		20584 / London Nelson TS EOL Replace	203 / ENG & PROJ D	$K	($3,115)		($700)	($1,650)	($765)	

9.1.4 PROJECT ALTERNATIVE – TYPE B FORECAST ACCOMPLISHMENTS

Sample showing Forecast Accomplishments entered in the in-service year of the project

Forecast

Erindale TS T5/T6; PCT & Component Replacement
Component Replacement

FY17 to FY22 (6 Years) Filter No Filter Inflated Inflated $K

	Account	Activity	AR	Organization	Unit	Investment T(	FY17	FY18	FY19	FY20	FY21	FY22
Draft forecast without actuals												
1 Erindale TS T5/T6; PCT & Component R												
1.1 Erindale TS T5/T6; PCT & Compone	TXCAP / Tx Capital		23446 / Erindale TS T5/T6; PCT	203 / ENG & PROJ D	$K	$6,558			$107	$318	$4,492	$1,641
Tx Removals	TXREM / Tx Removal		23446 / Erindale TS T5/T6; PCT	203 / ENG & PROJ D	$K	($459)			($8)	($22)	($314)	($115)
2 HVITs - 230kV												
Forecast Accomplishment		HVIT-230kV / 2	23446 / Erindale TS T5/T6; PCT	203 / ENG & PROJ D		6.00						6.00
3 LVITs - 44kV												
Forecast Accomplishment		LVIT-44kV / 44	23446 / Erindale TS T5/T6; PCT	203 / ENG & PROJ D		6.00						6.00
4 PCT												
Forecast Accomplishment		PCT / PCT	23446 / Erindale TS T5/T6; PCT	203 / ENG & PROJ D		1.00						1.00
Actuals					$K							
'Submitted' forecast without actuals					$K	$6,099			$100	$295	$4,177	$1,526
LOB Forecast					$K							

Sample showing Forecast Accomplishments entered in the year they are expected to occur (not typically used)

FY16 to FY22 (7 Years) Filter No Filter Inflated Inflated $K

	Account	Activity	AR	Organization	Unit	Investment Total	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Draft forecast without actuals													
1 Line Refurbishment - D2L													
1.1 Line Refurbishment - D2L, Dymond	TXCAP / Tx Capit		23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY	$K	$48,300	$500	$9,400	$19,200	$19,200			
Tx Removals	TXREM / Tx Rem		23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY	$K	($242)	($3)	($47)	($96)	($96)			
2 Overhead Conductor (Km)													
Forecast Accomplishment		OC-115kV / 115kv	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		58.00		8.00	25.00	25.00			
3 OPGW													
Forecast Accomplishment		OPGW / OPGW	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		58.00		8.00	25.00	25.00			
4 Tower Coating (Structures)													
Forecast Accomplishment		PLCOATING / Tower Coatir	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		260.00		60.00	100.00	100.00			
5 Switches - ABS													
Forecast Accomplishment		SWAB-115kV / 115kV	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		5.00			3.00	2.00			
6 Switches - Grounding Switches													
Forecast Accomplishment		SWGRND-115kV / 115kV	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		2.00			1.00	1.00			
7 Insulators													
Forecast Accomplishment		IN-115kV / 115kV	23499 / D2L,Upper Notch	203 / ENG & PROJ DELIVERY		1,040.00		40.00	500.00	500.00			

9.2 APPENDIX B – LIST OF ACCOUNT CODES

- **COMCAP** Common Capital
- **COMOMA** Common OMA
- **DXCAP** Dx Capital
- **DXCON** Dx Capital Contribution
- **DXOMA** Dx OM&A
- **DXREC** DX Recovery
- **DXREM** Dx Removals
- **TXCAP** Tx Capital
- **TXCON** Tx Capital Contribution
- **TXOMA** Tx OM&A
- **TXREC** TX Recovery
- **TXREM** Tx Removals

AIP CRITICAL INPUTS –CHECKLIST

http://hydronet.hydroone.com/LoB/Operations/PO/TAM/AIP/Reference_Materials/AIP Critical Input Checklist.docx

Dx Investment Planning Cycle
2017 - 2022

Management Training
May 2016

Agenda

- Investment Planning Pain Points
- Schedule
- Key Responsibilities
- Optimization
- Risk Calibration Session
- Investment Categorization
- Investment Health Report
- Investment Approval

Prioritized IPP Pain Points to be Addressed this cycle:

Pain points prioritized by criticality and ease of addressing

1. Lack of clarity of financial boundary conditions
2. Spend categories not linked to outcome-driven objectives
3. Business values/weights do not reflect current corporate strategy
4. Planners/managers do not understand optimization process
5. Lack of feedback received on input to IPP process
6. Planner inputs are of inconsistent quality
7. Insufficient time for investment definitions + quality check
8. Inaccuracy / lack of cost-estimates for potent. investments
9. Risk evaluation process is not consistently applied
10. Invest. not tracked against expected perform. outcomes

"Quick wins" | Intermediate targets | Long-term efforts

Dx Investment Plan Schedule

June 2	• Director Kickoff
June 6 - 30	• Planner Input
July 4 - 29	• Manager/Director Review • Risk Calibration Session – July 12
Aug 1 – 12	• QA & Optimization • **First Draft of Accomplishment File**
Aug 15 – Sept 16	• 3rd Party Review • Enterprise Engagement • iPAD Development
Sept 19 – 30	• Investment Plan Finalization • CEO/CFO Plan Review – Sept 26 • **Final Draft of Accomplishment File**

Key Responsibilities of Management…

- Communication of Corporate Direction to Planners
- Ensure Investments entail:
  - Valid alternatives
  - Defensible Risk Assessment
  - Appropriate Categorization
  - Completeness & Accuracy
- Complete Manager's Checklist
- Approval of Investments thru AIP Workflow
- Adhere to Schedule Timelines

Agenda

- Investment Planning Pain Points
- Schedule
- Key Responsibilities
- **Optimization**
- Risk Calibration Session
- Investment Categorization
- Investment Health Report
- Investment Approval

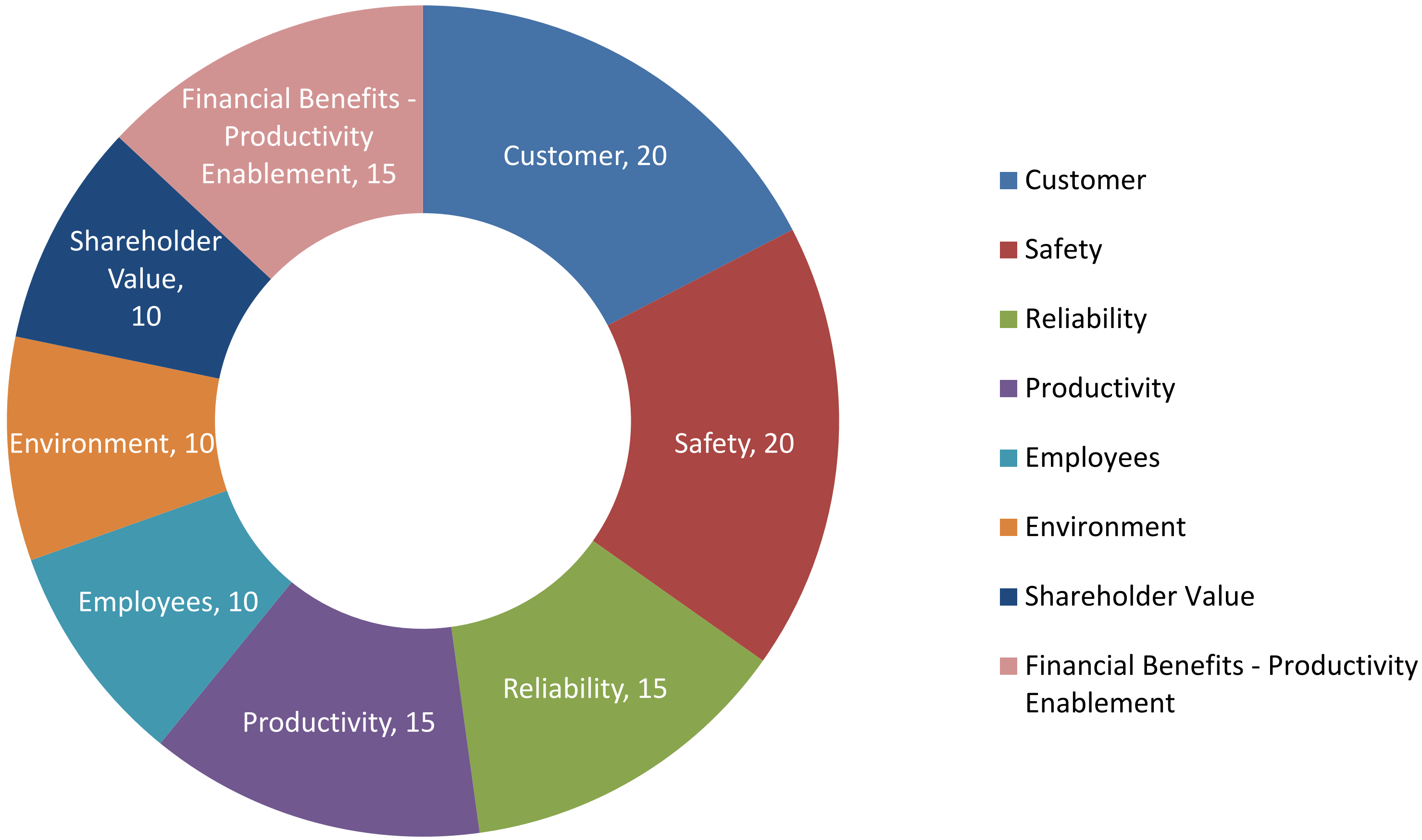
	IPP Pain Point Addressed
3	Business values/weights do not reflect current corporate strategy
4	Planners/managers do not understand optimization process

Value for Objectives: The Foundation for Optimization

- Goal: Maximize value to the corporation with regard to corporate objectives while staying within constraints
- Value: Risk Mitigated, Benefits, and/or KPI Improvements
- Financial Constraints Applied:

Transmission OMA	Distribution OMA
Transmission Capital	Distribution Capital

No Change to the Current Business Objectives and Weightings is Assumed



Note: individual weightings are determined through the allocation of 115 total value points

AIP Uses Value/$ for Optimization

Scenario: Aline's Investment Planning Company (A.I.P. Co.) must determine the optimal selection of seasons tickets given the constraints provided

	Cost		Value	
	Year 1	Year 2	Year 1	Year 2
Blue Jays	$100	$50	2000	4000
Raptors	$200	$100	500	6000
Leafs	$500	$30	4000	1000

Constraint	
Year 1	Year 2
$500	$150

Result

- Prioritize on Value:

  Year 1 = Leafs
  Year 2 = Raptors, Blue Jays

- Prioritize on Value/$

  Year 1 = Blue Jays, Raptors
  Year 2 = Blue Jays, Raptors

Investment Alternatives Produce a more Optimal Plan

Scenario: A.I.P. Co. must determine the optimal selection given the updated event alternatives and constraints provided

	Option	Cost		Value		Value/$	
		Year 1	Year 2	Year 1	Year 2	Year 1	Year 2
TFC	-	$40		200		5	
Leafs	Yr 1 or 2		$500		4000		8
Blue Jays	100 level	$100	$100	2000	4000	20	40
	500 level	$35	$35	1400	2600	40	74
Raptors	Gold	$200	$200	6000	8000	30	40
	Purple	$110	$110	3300	2100	30	19

Constraints		
	Year 1	Year 2
Financial	$550	$700
Must Do	TFC	

Investment Alternatives can Affect the Ability to Achieve an Optimal Plan

Option 1: Leafs selected Year 2

	Option	Cost		Value		Value/$		
		Year 1	Year 2	Year 1	Year 2	Year 1	Year 2	
TFC	-	$40		200		5		Must Do
Leafs	Year 2		$500		4000		8	No Shift
Blue Jays								
	500 level	$35	$35	1400	2600	40	74	High Value/$
Raptors								
	Purple	$110	$110	3300	2100	30	19	To Meet Constraint

Result:

Relax Constraints					
Year 1			Year 2		
Constraint	Cost	Value	Constraint	Cost	Value
$700	$185	4900	$550	$645	8700

Investment Alternatives can Affect the Ability to Achieve an Optimal Plan

Option 2: Leafs selected Year 1

	Option	Cost		Value		Value/$		
		Year 1	Year 2	Year 1	Year 2	Year 1	Year 2	
TFC	-	$40		200		5		Must Do
Leafs	Year 1	$500		4000		8		1 Year Shift
Blue Jays								
	500 level	$35	$35	1400	2600	40	74	High Value/$
Raptors								
	Purple	$110	$110	3300	2100	30	19	To Meet Constraint

Result:

Optimal					
Year 1			Year 2		
Constraint	Cost	Value	Constraint	Cost	Value
$700	$685	8900	$550	$145	4700

Alternative Structure can help with Reaching Constraint Levels

Optimization Results Comparison					
	Cost		Value		
	Year 1	Year 2	Year 1	Year 2	Total
Constraint	**$700**	**$550**			
Option 1	$185	$645	4900	8700	13600
Option 2	$685	$145	8900	4700	13600

Observation: Potential for additional events to be purchased up to constraint amount for Year 1 of the optimal solution.

Cause: Straight-line Alternative Structure and Major Project costs

Solution: Possible Growth or Decay Alternative Structure for Program Type Investments

Optimization of Common Costs is Dependent on both Portfolios

Scenario: A.I.P. Co. must determine the optimal selection given the updated events and constraints provided

Sports					Arts				
Event	Option	Cost	Value	Value/$	Event	Option	Cost	Value	Value/$
Blue Jays	100 level	$100	2000	20	Cats	-	$125	7000	56
	500 level	$35	1400	40	TIFF	VIP	$400	8000	20
						Reg	$150	2200	15

Optimization of Common Costs is Dependent on both Portfolios

Scenario: A.I.P. Co. must determine the optimal selection given the updated constraints provided

Sports				
Event	Option	Cost	Value	Value/$
Blue Jays				
	500 level	$35	1400	40
Child	Great	$180	3360	19

High Value/$

High Value/$

	Sports	Arts
Constraint	$250	$600
Cost	$219	
Value	4760	

Optimization of Common Costs is Dependent on both Portfolios

Scenario: A.I.P. Co. must determine the optimal selection given the updated constraints provided

Sports					Arts				
Event	Option	Cost	Value	Value/$	Event	Option	Cost	Value	Value/$
Blue Jays					Cats	-	$125	7000	56 Must Do
	500 level	$35	1400	40	TIFF	VIP	$400	8000	20 Value/$
Child					Child				
						Good	$24	400	17

	Sports	Arts
Constraint	$250	$600
Cost	~~$219~~ $91	$549
Value	~~4760~~ 2000	15400

Agenda

- Investment Planning Pain Points
- Schedule
- Key Responsibilities
- Optimization
- **Risk Calibration Session**
- Investment Categorization
- Investment Health Report
- Investment Approval

IPP Pain Point Addressed
9 Risk evaluation process is not consistently applied

Risk mitigation is a **consistent standard** used to va investments, and is used to **facilitate trade-offs between investments**

Risk Assessment Process

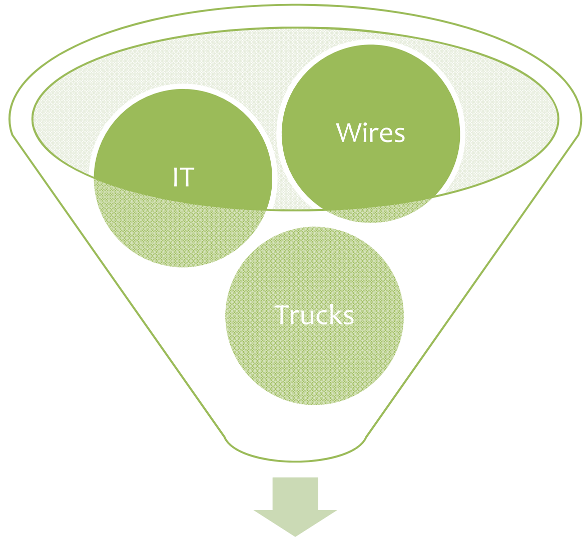
- For each identified investment need, risk is assessed against the potential impact on the Company's Business Values; investment alternatives are developed which may reduce the probability (risk abatement) and/or the consequence (risk mitigation) of the risk occurrence.
- **The risk assessment process allows investments to be compared** to one another on a value basis **across different portfolios**.

Investment Optimization Process

- The Investment Optimization process considers different investment increments/timing comprised of different risk management alternatives to facilitate tradeoffs between risk, cost and performance.
- The result is an investment plan that manages risk consistent with corporate direction and directs resources ($) to where they provide the maximum business value within the financial guidance provided.

Role of Calibration Session

- **If risk assessments are not properly calibrated** across business units, the optimized **investment portfolio may not** adequately **reflect the Company's priorities**
- The calibration sessions will focus on two dimensions:
  - Investment Flexibility
  - Risk Assessment Validation



Optimized Investment Plan

Why calibrate risk across LOBs?

Everyone competes for funding – if there is too much "mandatory", other work is reduced/deferred

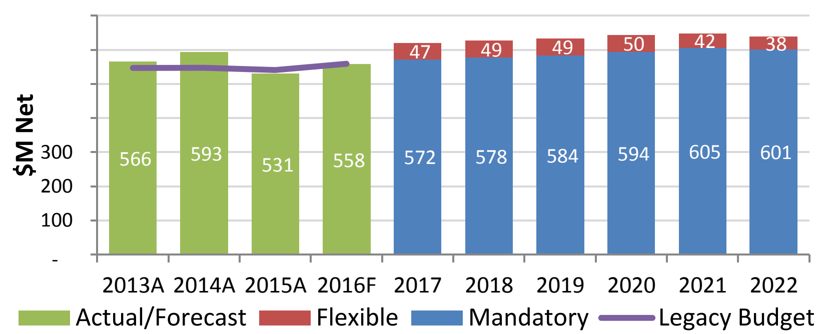
Observation:
- An increasing portion of the enterprise portfolio is being deemed "mandatory"

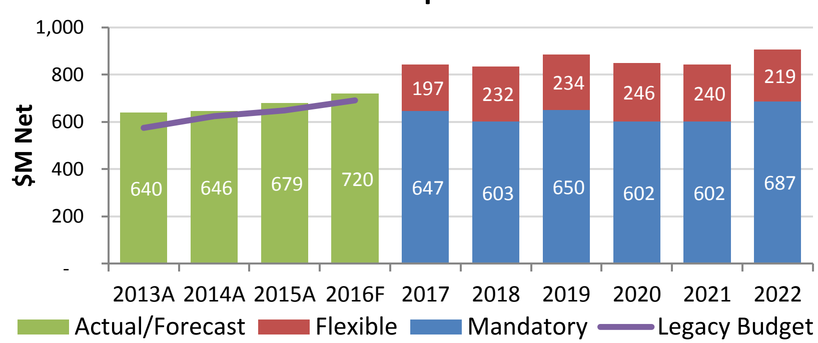
Workshop Purpose:
- To understand the level and composition of "mandatory" investments
- **Distinguish between investments that are beyond the control of the Company** *("mandatory")* **and those that are at the discretion of the Company** *("flexible").*

Implication:
- You are all competing for limited resources
- **If too much** of the investment portfolio is deemed to be **"mandatory" there is limited ability to accommodate more discretionary work** *(i.e. select projects/incremental volumes get "squeezed out").*

Potential Outcomes:
- **Acceptance** of "mandatory" investments **or reclassification** of "mandatory" investments
- Separation of investment elements into base (mandatory) and enhancement (flexible)

Why discuss investment flexibility?





Mandatory investments include:
- Executing Projects
- Demand/Contract based programs
- Vulnerable(minimum) level of programs
- Single alternative programs
- Non-shift-able, unreleased projects

Data as of March 14th, 2016

Flexible investments include:
- Incremental Project/Program levels
- Shift-able, unreleased projects (shift-able by 1 year or more)

Everyone competes for funding – if risk assessments are not aligned, the investment plan may not reflect the Company's priorities

Observation:

- Risk assessments across LOBs may not be consistent

Workshop Purpose:

- To understand each LOB's approach to risk assessments
- **To normalize risk assessment outliers and improve consistency**

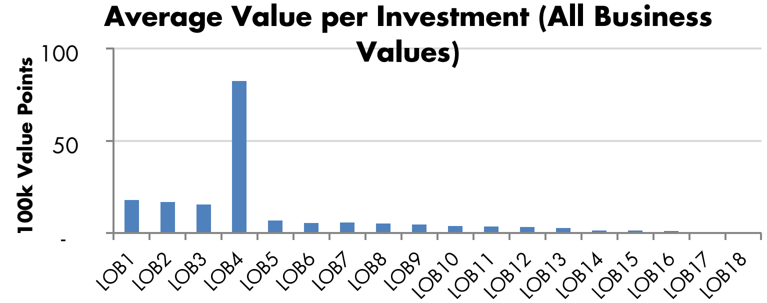
Implication:

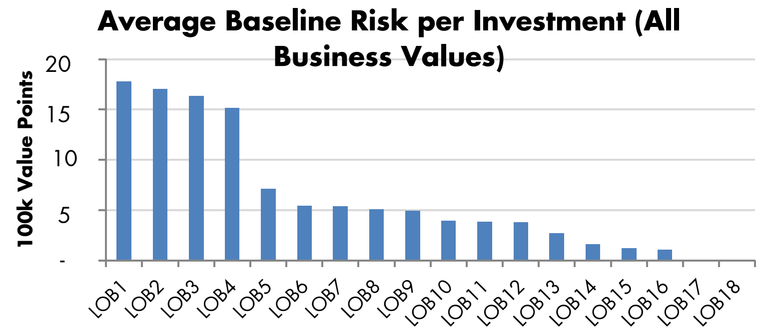
- You are all competing for limited resources
- The optimization process seeks to maximize value within the financial guidance identified
- **If an investment's risk mitigation** or productivity enhancement is **"overstated",** that investment may be selected in the optimization process, while **other worthwhile, higher operational risk investments** may be deferred*(assuming the mandatory level of investment does not exceed the financial guidance)*

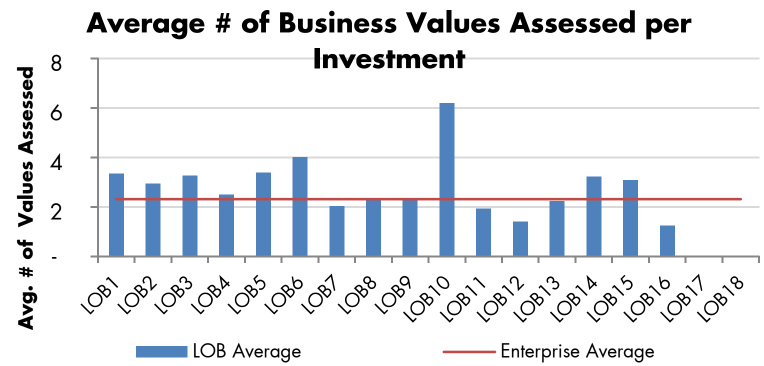
Potential Outcomes:

- **Acceptance or revisions** to risk assessment

Why validate investment risk assessments?







Data as of March 14th, 2016

The Risk Calibration session will cover Investment Flexibility and Risk Analysis

Session	Key Questions to Consider/Address
Investment Flexibility	**Portfolio Questions:** • Is there variability in your investments? • How did you arrive at your mandatory/vulnerable/minimum funding level request? • What type of work is included in your mandatory bucket? • If the investment is mandatory, why now or at the time proposed? • Did you contemplate +/- 10% adjustments to your portfolio? • Did you consider a 1 or 2 year deferral? • Is the entire investment mandatory, or are there flexible/discretionary elements? • Is your mandatory level aligned with historic budgets or historic expenditures? **Select Investments:** • How did you determine your minimum funding level?
Risk Analysis	**Portfolio Questions:** • What are the largest risks facing your portfolio? • What would the impact of a +/-10% change to your investment portfolio be? • How did you determine the business values applicable to your portfolio and the level of risk mitigated? • Are you relatively aligned with other planning groups? **Select Investments:** • How did you assess the baseline and residual risk?

What will be covered?

6 week outlook includes investment development customer consultations, risk calibration and management review

- **Risk calibration session is scheduled for July 12**

- A **standard template** will be developed and communicated to all participants; the expectation is that all materials will have a similar look/feel

- **Data will be pulled approximately 15 days before the calibration session** and sent to participants *(week of June 27)*:
  - Historic/forecast expenditures vs. current minimum/flexible investment outlook
  - Average risk/value assessment relative to other LOBs
  - Listing of significant investments to be covered as part of the workshop; significant investments may be identified based on:
    - » Risk/value score;
    - » Planned expenditures;
    - » Baseline risk assessment;
    - » Value per $; or
    - » Other considerations

What's next?

Agenda

- Investment Planning Pain Points
- Schedule
- Key Responsibilities
- Optimization
- Risk Calibration Session
- **Investment Categorization**
- Investment Health Report
- Investment Approval

IPP Pain Point Addressed	
2	Spend categories not linked to outcome-driven objectives

Investments segmented into foundational and enhancement categories with different purposes

	Investment category	Purpose
	Note: Will also consider applicability to Tx	
1 Foundational	a Asset renewal / maintenance b Customer connections c Safety, security, enviro (compliance) d Customer projects (ongoing) e Outage response f Facilities g Enterprise IT	**Maintain current reliability risk and system performance** • Continue to prioritize based on existing risk model / investment planning process
2 Enhancement	a Reliability enhancement b Grid mod (comms / automation) c Advanced analytics d Distributed Energy Resources enablement e Additional capacity / reserves f Grid hardening	**Enhance performance and deliver outcomes desired by customers**

Outcome	Metric
Improved reliability	$ / ACI
Reduced O&M	Annual savings / $ invested
Avoided CapEx	20-year NPV
Cust. energy efficiency / conservation	Load reduction / $ invested
New cust. products / services	Qualitative assessment

Customer input will help determine enhancement outcomes to prioritize in investment plan

1. Note: Foundational investments are those that are required for Hydro One to continue to deliver safe, reliable, and efficient service to all customers

Investments segmented into foundational and enhancement categories with different purposes

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Investment category | **Requirements**

Note: Will also consider applicability to Tx

1 Foundational

- a Asset renewal / maintenance
- b Customer connections
- c Safety, security, enviro (compliance)
- d Customer projects (ongoing)
- e Outage response
- f Facilities
- g Enterprise IT

2 Enhancement

- a Reliability enhancement
- b Grid mod (comms / automation)
- c Advanced analytics
- d Distributed Energy Resources enablement
- e Additional capacity / reserves
- f Grid hardening

Proper Categorization to be determined by Business Unit

Framework for Reporting in

Dx Rate Filing

Customer input will help determine enhancement outcomes to prioritize in investment plan

1. Note: Foundational investments are those that are required for Hydro One to continue to deliver safe, reliable, and efficient service to all customers

Agenda

- Investment Planning Pain Points
- Schedule
- Key Responsibilities
- Optimization
- Risk Calibration Session
- Investment Categorization
- Investment Health Report
- Investment Approval

IPP Pain Point Addressed
6 Planner inputs are of inconsistent quality
7 Insufficient time for investment definitions + quality check

Investment Health Report to ensure Completeness and Accuracy of Investments

- Objective:
  - Enhance quality assurance and minimize post-optimization changes
  - Facilitate time management of Investment Completion/Approvals for Planners/Managers
- Structure:
  - Reported Weekly
  - Summarized by Driver Owner

Investment Reporting to Minimize Post-Optimization Changes

QA Verification	Report Ending	Investment Completion	Investment Approvals
Categories	**Week**	**Target**	**Target**
Planning Timelines	1	30%	20%
Risk Evaluation (High Level)	2	55%	40%
Data Input Completion	3	75%	75%
AIP-SAP Key Component Alignment	4	100%	100%

Note: Targets are to serve as a guide and can be measured by:

- Investments routed through Workflow Approval
- Investment Components (Strategy, Risk, Costs etc)

Investment Approval Process to Drive Investment Quality

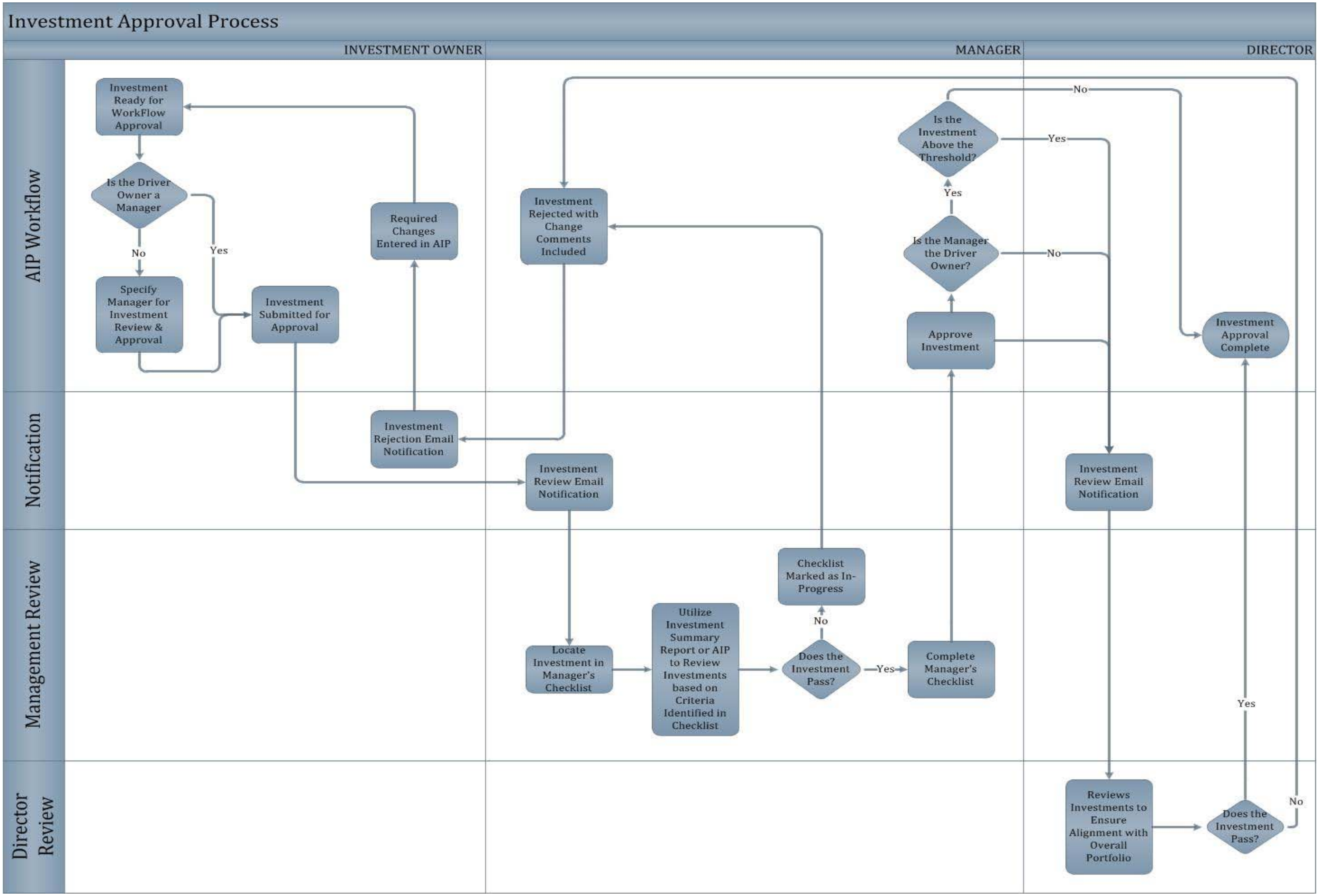
- Objective: Guide Manager's Review thru key investment characteristics for Short-term Planning Investments
- Components:
  - Manager's Checklist via SharePoint
  - AIP Workflow Approval
- Output:
  - Facilitates Investment Planning Process Metrics to be reported to Executives
  - Ensures Comprehensive Investment Summary Reports as potential Rate Filing Evidence

Investment Approval Process

Role	Responsibilities
Parent Portfolio Owner	• Final Approval for Investments over given threshold • $10M Projects/$15M Programs
Driver Owner	• Mandatory – Manager/Director • Manager - Completes Manager's Checklist • Final Approval via AIP Workflow
Reviewer 1	• Optional if Driver Owner is Director • Completes Manager's Checklist
Investment Owner	• Initiates Workflow • Specifies Reviewer 1 if required

Approval via Workflow

Rejected Workflow returns to Investment Owner


Investment Approval Process
INVESTMENT OWNER
MANAGER
DIRECTOR
AIP Workflow
Notification
Management Review
Director Review
Investment Ready for WorkFlow Approval
Is the Driver Owner a Manager
No
Yes
Specify Manager for Investment Review & Approval
Investment Submitted for Approval
Required Changes Entered in AIP
Investment Rejection Email Notification
Investment Rejected with Change Comments Included
Investment Review Email Notification
Locate Investment in Manager's Checklist
Utilize Investment Summary Report or AIP to Review Investments based on Criteria Identified in Checklist
Does the Investment Pass?
Checklist Marked as In-Progress
Complete Manager's Checklist
Approve Investment
Is the Manager the Driver Owner?
Is the Investment Above the Threshold?
Investment Approval Complete
Investment Review Email Notification
Reviews Investments to Ensure Alignment with Overall Portfolio
Does the Investment Pass?

Investment Approval Process

- Email Notification Alert

2017-2022

From: AssetPlanningDev@HydroOne.com

To: BRODIE Aline

Cc:

Subject: Investment Review for "Investment: AIP005656 / TRAINING DS Station refurbishment Program - Wojtek"

Dear Aline Brodie,

A workflow is pending your review, as described below. Please go to your workflow inbox item.

Link to Investment Approval Form

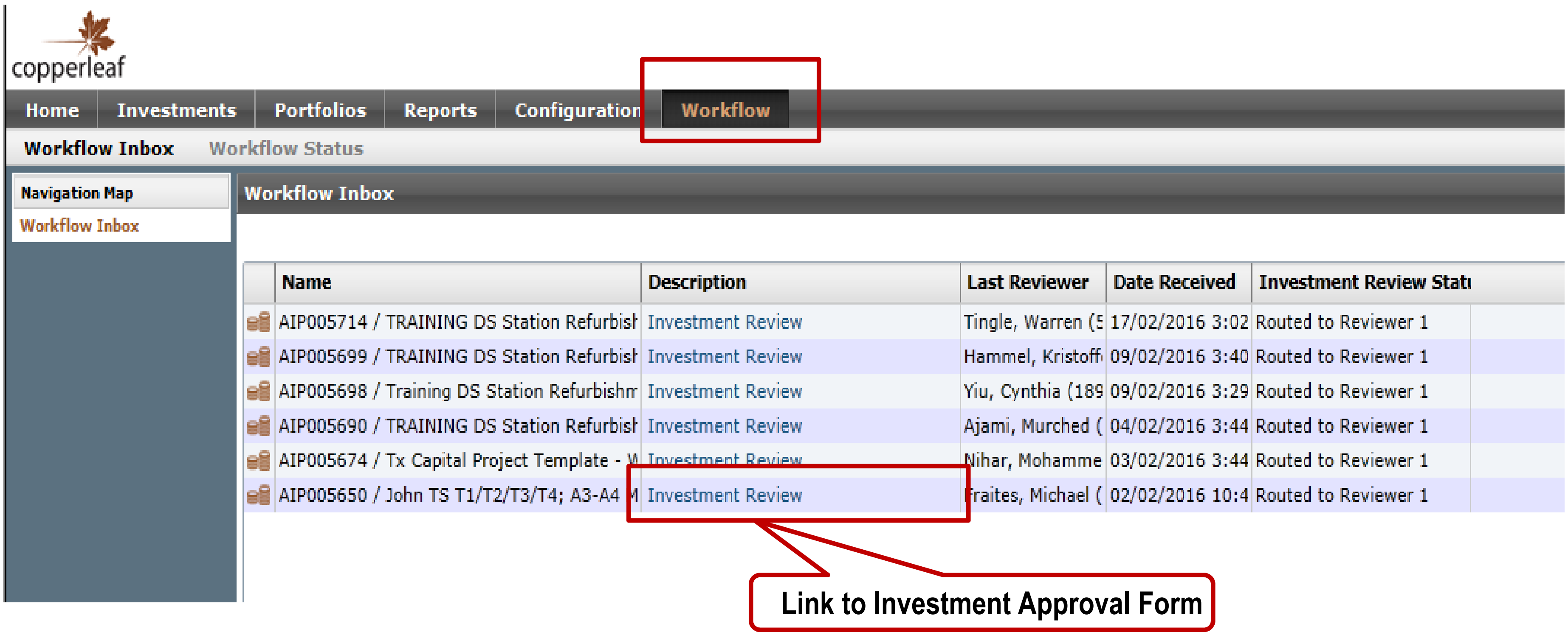
Workflow Task:	Reviewer 1 to review investment
Workflow Task Description:	Provide acceptance (Approve), rejection (Reject) or re-assignment (Re-Assign) of the investment review
Investment/Portfolio:	Investment: AIP005656 / TRAINING DS Station refurbishment Program - Wojtek
Workflow Name:	Investment Review
Workflow Description:	Send investment to Driver Owner and then to next level Manager
Workflow Initiator:	Maroszek, Wojciech (188626)

Workflow Details:

02/02/2016 03:04:10 PM	Brodie, Aline (188414)	Pending	
02/02/2016 03:04:09 PM		Informational	Investment 'AIP005656 / TRAINING DS Station refurbishment Program - Wojtek' is locked
02/02/2016 03:04:08 PM		Informational	Workflow task function "Submit Draft Forecast" has failed.
02/02/2016 03:04:08 PM		Failure	Submit Draft Forecast: Cannot submit the investment's current draft forecast because there are no unsubmitted changes.
02/02/2016 03:04:01 PM		Informational	Task Reviewer 1 to review investment will send to the following users for approval [Brodie, Aline (188414)]
02/02/2016 03:04:01 PM	Maroszek, Wojciech (188626)	Initiated	Please approve my investment

Investment Approval Process

- Investments Pending Review
  - AIP Workflow Inbox



Investment Approval Process

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Home | Investments | Portfolios | Reports | Configuration | Workflow

Workflow Inbox Workflow Status

Navigation Map
Workflow Inbox

Approval Inbox Item

Workflow Task Reviewer 1 to review investment
Task Description Provide acceptance (Approve), rejection (Reject) or re-assignment (Re-Assign) of the investment review
Investment TRAINING DS Station Refurbishment Program - Kris Hammel (AIP005699)
Planning Portfolio N.D.C.1.100 - Capital Investment Driver
Workflow Investment Review
Workflow Description Send investment to Driver Owner and then to next level Manager
Workflow Initiator Hammel, Kristoffer (186930)

Date	User	Action	Comment
02/09/2016 03:40:27 PM	Brodie, Aline (188414)	Pending	
02/09/2016 03:40:27 PM		Informational	Investment 'AIP005699 / TRAINING DS Station Refurbishment Program - Kris Hammel' is locked
02/09/2016 03:40:27 PM		Informational	Workflow task function "Submit Draft Forecast" has failed.
02/09/2016 03:40:27 PM		Failure	Submit Draft Forecast: Cannot submit the investment's current draft forecast because there are no unsubmitted changes.
02/09/2016 03:40:20 PM		Informational	Task Reviewer 1 to review investment will send to the following users for approval [Brodie, Aline (188414)]
02/09/2016 03:40:20 PM	Hammel, Kristoffer (186930)	Initiated	

Attachments

Date	User	File	Comments

Please respond by completing the form below, then click submit

Comment

Action Approve Reject Re-assign

Submit

Workflow Tracking

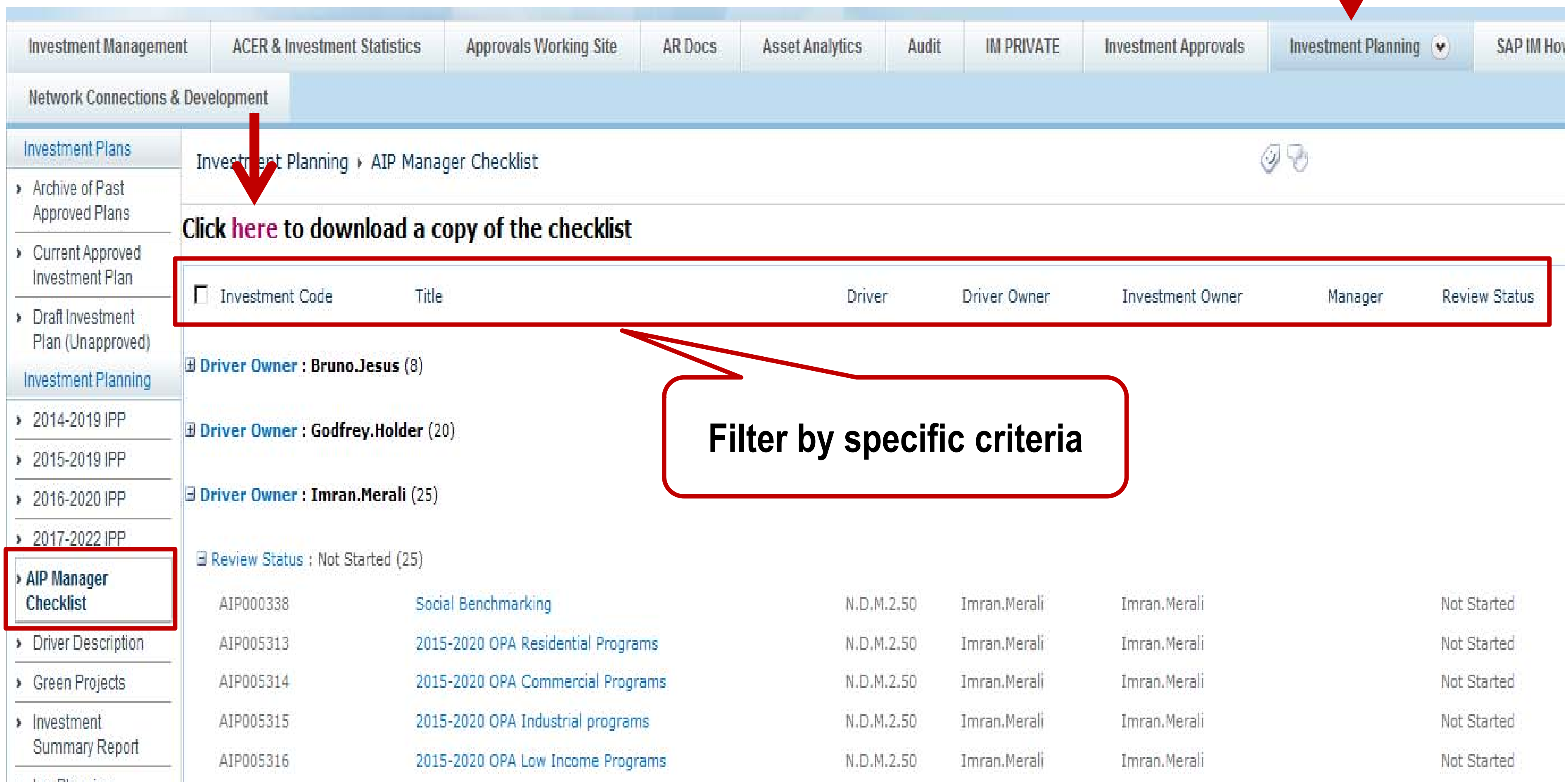
AIP Code Reference for Manager's Checklist

Investment Review Material

1) Within AIP via link
2) Investment Summary Report via AR Docs

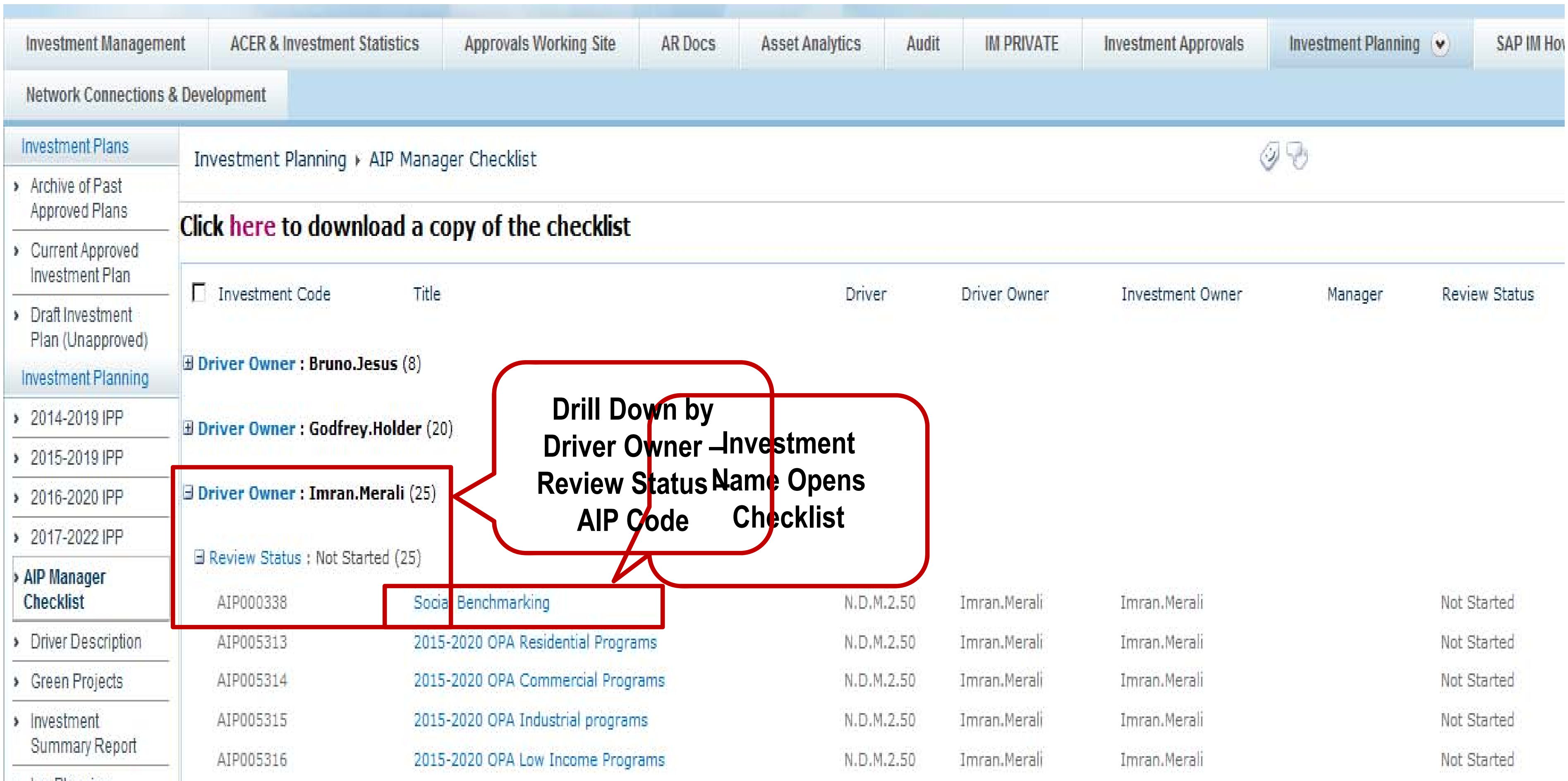
Investment Approval Process

Manager's Checklist



Investment Approval Process

Manager's Checklist



Investment Approval Process

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Investment Checklist Summary

Edit Item to Begin or Complete Checklist

AIP Manager Checklist - Social Benchmarking

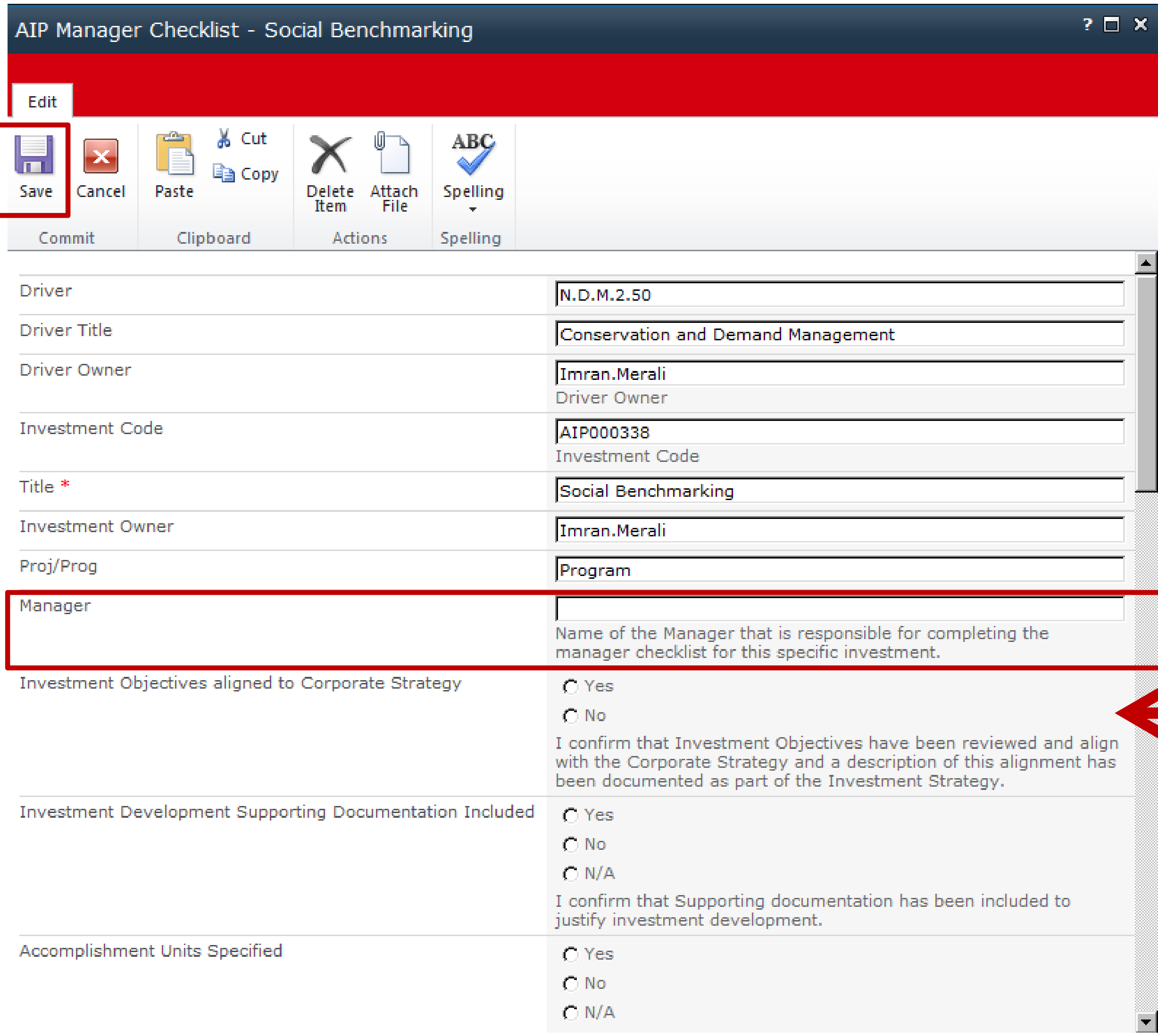
View

Edit Item | Version History | Manage Permissions | Delete Item | Alert Me

Manage | Actions

Driver	N.D.M.2.50
Driver Title	Conservation and Demand Management
Driver Owner	Imran.Merali
Investment Code	AIP000338
Title	Social Benchmarking
Investment Owner	Imran.Merali
Proj/Prog	Program
Manager	
Investment Objectives aligned to Corporate Strategy	
Investment Development Supporting Documentation Included	
Accomplishment Units Specified	
Asset Analytics Utilization	
Other Data Sources Considered	
Investment Categorization is Logical	
Planning Timelines Are Logical	
Timing to Cash Flows Are Logical	
Service Provider Agreement With Alternatives	
Estimate Provided by WPM	
Alternatives Entered and Selectable	
Project Shift-able as Appropriate	
Gantt Chart Provided	
Review Status	Not Started

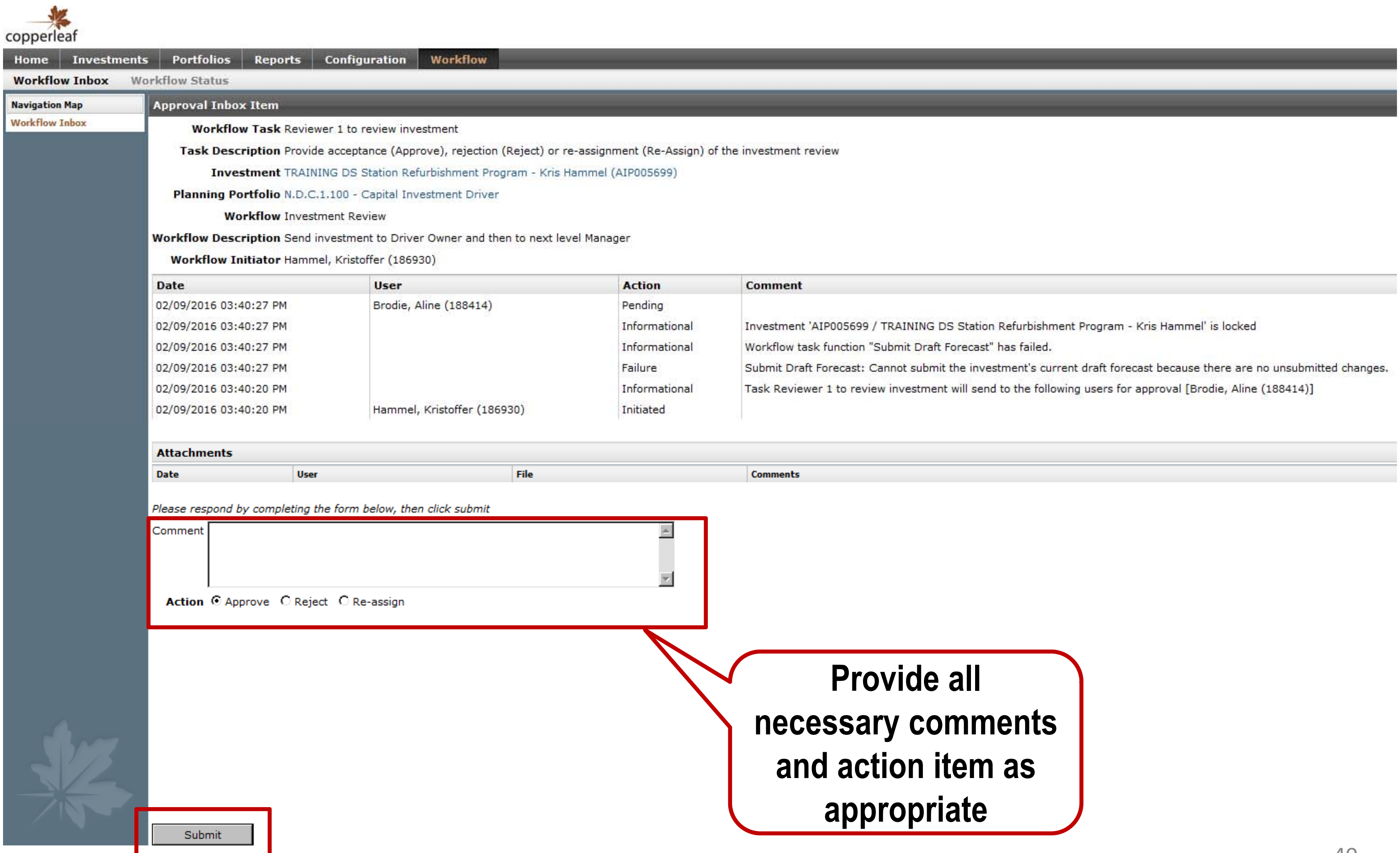
Investment Approval Process



Don't forget to save!

Manager's Checklist to Confirm Multiple Investment Characteristics

Investment Approval Process



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Home | Investments | Portfolios | Reports | Configuration | Workflow

Workflow Inbox   Workflow Status

Navigation Map

Workflow Inbox

Approval Inbox Item

Workflow Task Reviewer 1 to review investment

Task Description Provide acceptance (Approve), rejection (Reject) or re-assignment (Re-Assign) of the investment review

Investment TRAINING DS Station Refurbishment Program - Kris Hammel (AIP005699)

Planning Portfolio N.D.C.1.100 - Capital Investment Driver

Workflow Investment Review

Workflow Description Send investment to Driver Owner and then to next level Manager

Workflow Initiator Hammel, Kristoffer (186930)

Date	User	Action	Comment
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02/09/2016 03:40:20 PM		Informational	Task Reviewer 1 to review investment will send to the following users for approval [Brodie, Aline (188414)]
02/09/2016 03:40:20 PM	Hammel, Kristoffer (186930)	Initiated	

Attachments

Date	User	File	Comments

Please respond by completing the form below, then click submit

Comment

Action Approve Reject Re-assign

Submit

Provide all necessary comments and action item as appropriate

Prioritized IPP Pain Points to be Addressed this cycle:

Pain points prioritized by criticality and ease of addressing

#	Pain point	Addressed
1	Lack of clarity of financial boundary conditions	
2	Spend categories not linked to outcome-driven objectives	✓
3	Business values/weights do not reflect current corp. strat.	✓
4	Planners/managers do not understand optimiz. process	✓
5	Lack of feedback received on input to IPP process	
6	Planner inputs are of inconsistent quality	✓
7	Insufficient time for investment definitions + quality check	✓
8	Inaccuracy / lack of cost-estimates for potent. investments	
9	Risk evaluation process is not consistently applied	✓
10	Invest. not tracked against expected perform. outcomes	

"Quick wins" (1–4) — Intermediate targets (5–7) — Long-term efforts (8–10)

Questions?

APPENDIX

Dx Investment Plan Schedule

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Date	Segment	Key Stakeholder(s)	Description
May 25 - 31	Director/Management Training	Investment Management, Planning	AIP Team to provide insight into AIP's optimization process and review requirements for the new Manager's Checklist
June 2	Investment Planning Kickoff	Planning, Operations, Finance, Regulatory & Investment Management	AIP Team to review schedule, requirements etc of the Dx Investment Planning Process with key stakeholders at Director/Management Level
June 6 – July 1	Planner Input	Planning (Operations)	AIP Tool Open to Planners with investments under Dx CapEx & Dx OMA only
July 4 – July 29	Management Review & Approval	Planning (Operations)	Management Review including Manager's Checklist with Final Investment Approval through AIP Workflow
July 12	Risk Calibration	Planning	AIP Team to facilitate Risk Calibration Session(s) to determine consistent risk approach across the all Planning organizations
Aug 1 –12	QA Optimization	Investment Management	AIP Team to run QA & optimization on Dx CapEx & Dx OMA only
August 12	Hand-off for 3rd Party Review	Investment Management	Updated Accomplishment File due for 3rd Party Review
Aug 15 – 26	3rd Party Review	Regulatory	Optimized Dx Work Program to undergo 3rd Party Review
Aug 15 - Sept 16	Enterprise Engagement	Planning, Operations, Finance, Regulatory & Investment Management	Planning and Operations to review Accomplishment File as a result of all changes identified, provide feedback with any remaining adjustments required, final Director Approval
Aug 15 – Sept 16	iPad Development	Planning	Planning to document investment strategy and outcome as a result of the Planning Process in their respective iPADs
Sept 19 - 30	Accomplishment File #3 Finalization	Planning & Investment Management	AIP Team to finalize updates prior to Business Planning Hand-off
Sept 26	CEO/CFO Investment Plan Review	Planning, Operations, Finance, Regulatory & Investment Management	Investment Plan Review Session for CEO/CFO Approval (previously IRRC)
Sept 30	Business Planning Hand-off	Investment Management	Updated Accomplishment File due for Business Planning Board Prep

Foundational Investment Categorization

Category	Description
Asset renewal / maintenance	Investments focused on minimizing life-cycle asset costs while maintaining an acceptable risk and continuously delivering reliable service
Customer connections (new customers)	Investments related to providing service to new customers, including construction, meter installations, and other required investments to address load growth
Safety, security and enviro (compliance)	Investments to ensure transmission and distribution facilities and operations are in compliance with environmental, safety, and other regulations
Customer projects (existing customers)	Investments related to customer-requested work from existing customers, including design and relocation of services
Outage response	Investments (primarily O&M) focused on responding to outages and restoring service
Facilities	Routine investments for building required facilities for customer and workforce needs
Enterprise IT	IT capital programs related to hardware replacement, secure access to information and technology and investments related to Hydro One's Enterprise Information Systems

Enhancement Investment Categorization

Category	Description
Reliability enhancement	Investments focused on providing improved reliability (e.g., reducing SAIFI / CAIDI) through addressing root causes of reliability issues or mitigating reliability impact from routine events
Grid modernization (comms / automation)	Investments to modernize the electrical grid to provide real-time visibility and control capabilities . May include smart meters, remote controllable devices. or enhanced communication capabilities.
Advanced analytics	Investments focused on databases, software, and analytics applications to collect and utilize operational data (e.g. meters, assets, customers)
DER enablement	Investments focused on enabling the integration of significant amounts of new distributed resources, such as rooftop PV
Additional capacity / reserves	Investments which improve system resiliency through increased circuit redundancy, additional load capacity, and storage capabilities
Grid hardening	Investments which increase the grid's ability to reliably operate during major events related to weather or other adverse conditions

Investment Approval Targets set Roadmap to Completion

Driver Owner	Week 1 (20%)	Week 2 (40%)	Week 3 (75%)	Week 4 (100%)	Total	% under $3M
Imran Merali	5	5	8	7	25	48%
Godfrey Holder	4	4	7	5	20	85%
Bill Welch	1	2	3	3	9	100%
Bruno Jesus	1	2	3	2	8	100%
Scott McLachlan	0	1	2	1	4	100%
Lou Fortini	0	1	1	1	3	33%
Miroslav Kostic	0	0	1	1	2	100%
Mike Piggott	0	0	0	1	1	0%
Ronald Gentle	0	0	0	1	1	100%

Investment Approval Targets set Roadmap to Completion

Driver Owner	Week 1 (20%)	Week 2 (40%)	Week 3 (75%)	Week 4 (100%)	Total	% under $3M
JJ Blais	11	11	20	14	56	98%
Lincoln Frost-Hunt	6	6	11	8	31	71%

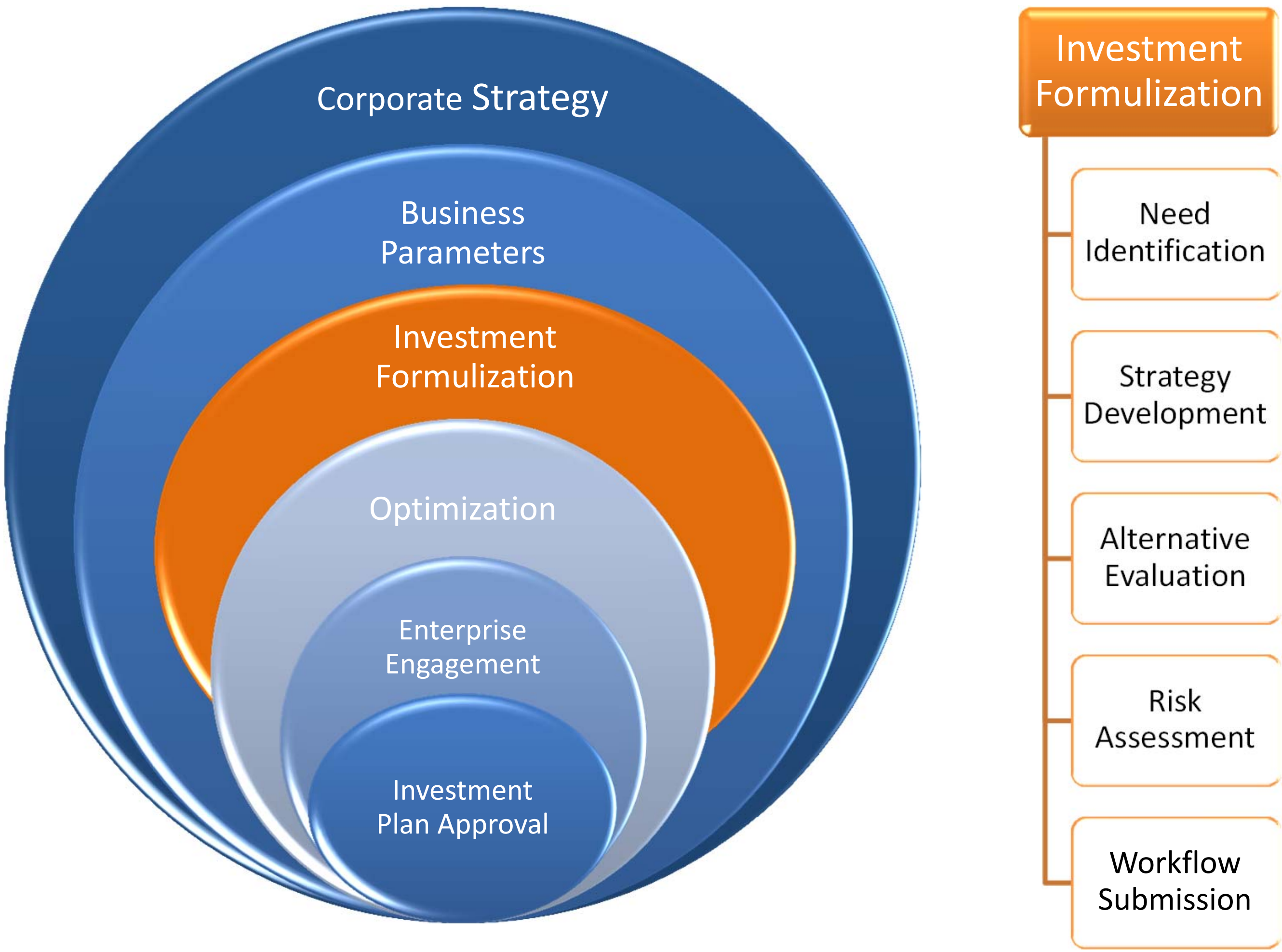
Investment Approval Targets set Roadmap to Completion

Driver Owner	Week 1 (20%)	Week 2 (40%)	Week 3 (75%)	Week 4 (100%)	Total	% under $3M
Sinisa Grkovic	19	20	35	25	99	53%
John Fuerth	10	10	19	13	52	90%
Peter Faltaous	6	6	10	8	30	87%
Luis Marti	1	1	1	2	5	80%

Investment Planning Schedule

Date	Segment	Duration
Training		
Jan 11 - Feb10	Planner & Manager Training	4 weeks
Input		
Jan 30	Operations provides Unit Price Catalogue; Planning accepts Unit Price Catalogue	1 day
Feb 1 - Mar 28	Planner Input	8 weeks
Feb 24	Investment Planning Drop-in Session (TCT 13-C)	½Day - AM
Mar 9 - 16	QA Review	1 week
Mar 22	Investment Planning Drop-in Session (TCT 13-C)	½Day - PM
Mar 28 – May 4	Manager/Director Review of Input	4 weeks
Apr 27 – May 3	Investment/Risk Calibration	1 weeks
Optimization and Review		
May 5 – May 18	QA and Optimization	2 weeks
May 19 – 25	Director Review of Optimization Results	2 weeks
May 26 – June 1	Executive Review	1 week
Enterprise Engagement		
June 2 – 20	Executing LOB Review (Lines, Forestry, Stations, E&C)	3 weeks
Investment Plan Approval		
June 30	IRRC IPP Review and Approval	1 day
June 30	Investment Plan Proposal Complete	

Your Role in the Investment Planning Process



Planning Consequences

	SAFETY*		CUSTOMER			ENVIRONMENT		EMPLOYEES	PRODUCTIVITY	RELIABILITY							
Event	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction inOSHA Recordable injuries.	Public Injuries (with Hydro One at fault)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Failure to meet Service Quality Indicies.	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Adverse Environmental Impact	Adverse emission (carbon footprint / greenhouse gas)	Change in employee engaement survey results.	Failure meet Unit Cost targets per plan	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparables).	Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	Frequency of Distribution Outages Number of customers interrupted for > 1 minute	Cost Impact
Minor1 Noticeable disruption to results; manageable.	Meets planned improvement in health and safety targets	No Change in number of injuries	Meets planned improvement in customer satisfaction survey results (as measured by scorecard).	Achieved or exceeded Overall Expected Performance	Stable satisfaction as per survey responses (as measured by scorecard).	No impact on Hydro One Inc.	Aniticipated improvement relative to work program in carbon footprint / greenhouse gas are achieved.	On-plan improvement achieved in Employee Survey Results.	Unit costs reduction less than planned	< 12 MWh	No deterioration in reliability relative to current performance in the 5 year period.	< 240 MWh	<.001% (< 100 asset-hours, for an asset class with 1000 assets, where an asset-hour is defined as an asset being unavailable for 1 hour)		< 20,000 Customer Interruption Hours	< 10000 Interruptions	0-$500K
Minor2 Noticeable disruption to results; manageable.										12-30 MWh		240-600 MWh	0.001-0.0025% (100 asset-hours - 200 asset-hours, for an asset class with 1000 assets)		20,000 to 50,000 Customer Interruption Hours	10000 to 25000 Interruptions	$500K-$1M
Minor3 Noticeable disruption to results; manageable.										30-120 MWh		600-2400 MWh	0.0025-0.006% (200 asset-hours - 500 asset-hours, for an asset class with 1000 assets)		50,000 to 500,000 Customer Interruption Hours	25000 to 100000 Interruptions	$1M-$2M
Minor4 Noticeable disruption to results; manageable.										120-250 MWh		2400-5000 MWh	0.006-0.015% (500 asset-hours - 1000 asset-hours, for an asset class with 1000 assets)		500,000 to 5 Million Customer Interruption Hours (equivalent to SAIDI of <0.8 to 3.8 hrs)	100000 to 200000 Interruptions	$2M-$3M
Minor5 Noticeable disruption to results; manageable.	Safety targets met, but minor concerns regarding future performance.		Less than planned improvement in customer satisfaction survey results (as measured by scorecard).	Achieve only 95% (to 100%) of Overall Expected Performance	Less than planned improvement in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor impact on Hydro One Inc property only e.g. <3,000 L non-PCB material released or < 5% increase in non-recoverable spills/leaks above historical levels	Marginally less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Less-than-planned improvement achieved in Employee Survey Results.		250-600 MWh	Deterioration in reliability relative to current performance (but still within 1st quartile) for only one year in the 5 year period.	5000 MWh-12,000 MWh	0.015-0.04% (1000 asset-hours - 4000 asset-hours, for an asset class with 1000 assets)		5 Million to 7 Million Customer Interruption Hours (equivalent to SAIDI of 3.8 to 5.4 hrs)	200,000 to 500,000 Interruptions	$3M-$5M
Moderate Material deterioration in results; a concern; may not be acceptable; management response would be considered.	Less than planned improvement in health and safety performance	Small Increase in Number of Injuries	Increase in number of customer complaints; Some increase in number of customers falling outside of "delivery point performance standards"; Moderate deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in at least one segment.	Achieve on 90% (to 94%) of Overall Expected Performance	Slight deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor local offsite impact (e.g. a single residential property or private water supply); or Significant spill/release with impact on Hydro One Inc property only. e.g. 3,000 - 5,000 L non-PCB material released or 5 - 25% increase in non-recoverable spills/leaks above historical levels	Somewhat less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Much Less-than-planned improvement achieved in employee survey results.	Unit Costs not reduced	600-1500 MWh	Deterioration in reliability relative to current performance (but still within 1st quartile) for more than one year in the 5 year period.	12,000 MWh-30,000 MWh	0.04-0.1% (4000 asset-hours - 10,000 asset-hours, for an asset class with 1000 assets)	Impact 1 or 2 chronic outliers	7 Million to 8 Million Customer Interuption Hours (equivalent to SAIDI of 5.4 to 6.7 hrs)	500,000 to 1.25 Million Interuptions	$5M-$25M
Major Significant deterioration in results; not acceptable; management response.	No improvement in health and safety performance	Moderate Increase in Number of Injuries	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; High level (CEO, COO, etc.) calls to Hydro One CEO's office; Significant increase in number of customers falling outside of "delivery point performance standards"; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single segment.	Achieve only 80% (to 89%) of Overall Expected Performance	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).	Significant local offsite Impact (e.g., a public thoroughfare) e.g. >5,000 - 10,000 L non-PCB material released or >25% - 50% increase in non-recoverable spills/leaks above historical levels	No real improvement relative to work program in carbon footprint / greenhouse gas initiatives.	No improvement achieved in employee survey results.	Unit Costs increase by < 5%	1500-5000 MWh (e.g. In 2013, Armitage TS failure was 1,700 MWh and Manby TS failure was 3,400 MWh)	Deterioration to second quartile for only one year in the 5 year period.	30,000 MWh-100,000MWh	0.1 - 0.5% (10,000 to 40,000 asset-hours, for an asset class with 1000 assets)	Impact 2 to 5 chronic outliers	8 Million to 10 Million Customer Interruption Hours - note: current performance is 8.8 hrs and 5 year average is 8.4 hrs (equivalent to SAIDI of 6.7 to 8.3 hrs)	1.25 Million to 3.75 Million Interruptions	$25M-$100M
Severe Fundamental threat to operating results; immediate senior management attention.	Employee/contractor critical injury due to failure of managed system. Significant deterioration in health and safety performance.	Significant Increase in Number of Injuries	Customer associations (AMPCO, etc.) step up lobbying efforts for stricter penalties against Hydro One; Increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase significantly; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) across multiple segments.	Achieve only 67% (to 79%) of Overall Expected Performance.	Exponential increase (>30%) in: - call centre volumes (not storm related); - complaints received by field staff; - time and effort to resolve; Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Multiple local offsite impacts (e.g. multiple residential properties or private water supplies) e.g. >10,000 - 20,000 L non-PCB material released or >50% increase in non-recoverable spills/leaks above historical levels	Carbon footprint / greenhouse gas gets somewhat larger relative to work program and more visible to interested stakeholders.	Modest decline in employee survey results.	Unit Costs increase by 6% - 10%	5000-10,000MWh	Deterioration to second quartile for more than one year in the 5 year period.	100,000 MWh-200,000 MWh	0.5 - 1% (40,000 to 100,000 asset-hours, for an asset class with 1000 assets)	Impact 5 to 10 chronic outliers	10 Million to 15 Million Customer Interruption Hours (equivalent to SAIDI of 8.3 to 12.5 hrs)	3.75 Million to 7.5 Million Interruptions	$100-$300M
Worst Case Results threaten survival of company in current form; potentially full time senior management response until resolved.	Employee/contractor fatality or major permanent disability due to failure of managed system	Fatality or Major Permanent Disability	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically	Achieve only 25% (to 66%) of Overall Expected Performance.	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments	Widespread offsite impacts (e.g. Regional or Municipal water supply) e.g. >20,000 L non-PCB material released	Carbon footprint / greenhouse gas gets substantially larger relative to work program and more visible to interested stakeholders.	Sharp deterioration in employee survey results.	Unit Costs increase by > 10%	>10,000 MWh (for comparison, GTA flood in 2013 was 21,000 MWh).	Deterioration to third quartile at any time in 5 year period.	> 200,000 MWh	> 1% (100,000 asset-hours, for an asset class with 1000 assets)	Impact 10 or more chronic outliers	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)	>7.5 Million Interruptions	>$300M
Comments	Same as Corporate Risk Matrix with addition of Minor1 Consequence *Since there is a commitment by all parts of the business to manage the incidence of injuries and illnesses, it is important to assess the potential impact any asset investment plan might have on Health and Safety performance. This is not only true when an investment is specifically targeted to reduce Health and Safety risk, but also when the investment justification involves other stakeholder concerns, in order to determine if Health and Safety would be significantly affected. In those situations where Health and Safety could be significantly affected, risk mitigation strategies must be considered as part of the asset investment plan; and no investment level should be proposed where there is an "unmitigable" risk of serious injury, illness or fatality. Therefore, where an investment is justified by impact on Health and Safety, or where there is likely an identifiable and supportable impact on Health and Safety risk, the planner will request Health and Safety subject-matter-expert support to review the risk assessment and the data sources used (eg., Line of Business information, standards, regulations, best practices, industry sources, etc.) In these instances l t tD Wh t f i t	Same as Corporate Risk Matrix	Same as Corporate Risk Matrix with addition of Minor1 Consequence.	Same as Corporate Risk Matrix with addition of Minor1 Consequence. May wish to remove OEB Service Quality Indices as unclear as to how an individual planner would assess if Hydro One will "Achieve only 67% (to 79%) of Overall Expected Performance	Same as Corporate Risk Matrix with addition of Minor1 Consequence	The Environment is the same as the Corporate Risk Matrix, except that: 1. Split into 2 columns to make it easier to apply 2. Examples added to the adverse impact to help quantify the levels 3. Minor1 consequence added	see previous column	Same as Corporate Risk Matrix with addition of Minor1 Consequence.	This is the same as the Corporate Risk Matrix, except: 1. Excluded the Work Program Accomplishment metrics as Planners cannot apply these to individual program and project risk assessments.	Same as the Corporate Risk Matrix with addition of finer granularity to Minor1 through Minor5 Consequences.	Same as the Corporate Risk Matrix with addition of Minor1 Consequence.	This category has been added as a way of assessing the risk of operating without redundancy. It has been set as 1/20th the cost of a complete failure based on the assumption that there is approximately 5% probability of the redundant portion being failed or in maintenance, overloaded etc.	This has been added as a category for addressing situations where it is difficult to estimate the impact on reliability. For a simple starting point have assumed that there are "1000" of each asset in the asset category and consequently to increase unavailability by 1% for an entire asset class then 10 assets would have to be out for the whole year. These numbers could be improved to be asset class specific (i.e. based on the number of assets in a particular class). They could also be further refined to reflect the criticality of assets in a particular area.	This has been added to the Corporate Risk Matrix as a way of valuing investments for current worst served customers. We need to provide the list of specific outliers so that each program can understand which outliers are being addressed by a program.	Same as the Corporate Risk Matrix with addition of finer granularity fo Minor1 through Minor5 Consequences.	Values for this have been derived based on an estimate of the average cost of an interruption as $60. This is based on a study (see CopperLeaf White Paper) that shows for residential customers a cost of an outage at $3.90 and for small commercial a cost of $818, with a mix of 7% small commercial and 93% residential. Numbers can be converted to an impact on SAIFI by dividing by number of customers served by Hydro One Distribution. In a meeting on Aug. 3/2012 it was decided to scale these numbers by a factor of 3. Note that the Hydro One ADS project used the $1/CIM ($60 per hour) which is equivalent to the CopperLeaf suggestion….since they are based on the same underlying report. So Hydro One concurs and it is consistent with th l i ti d i	This ties to a Net Income Impact in the Corporate Risk Matrix. Simplified in the project matrix as Capital and OMA costs could have different impacts on Net Income and did not want planners to have to distinguish costs when identifying these risks and/or compute tax impacts. There is one shareholder value column that is present in the corporate risk matrix under shareholder value that is not present here: "Credit Worthiness". Any impacts of individual risks to credit worthiness should be expressed by the planner as a "Cost Impact".

Planning Consequences

	SHAREHOLDER VALUE			
Event	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Publice Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities (OEB/ IESO/NERC/NPCC/WSIB etc) including non- compliance.	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction
Minor1 Noticeable disruption to results; manageable.				No Consequence
Minor2 Noticeable disruption to results; manageable.				
Minor3 Noticeable disruption to results; manageable.				
Minor4 Noticeable disruption to results; manageable.				
Minor5 Noticeable disruption to results; manageable.	Some concern with management decisions; Occasional requests from owner for details	Credible letter(s) to Senior Management	Balanced; some challenges.	Regulatory Warning, conditional closeout without sanctions.
Moderate Material deterioration in results; a concern; may not be acceptable; management response would be considered.	Confidence in question; Owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action	Increase in Reporting Detail and Frequency (for HOI only)	Regulatory Order and/or financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry.
Major Significant deterioration in results; not acceptable; management response.	Material erosion in confidence; Shareholder Agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board	Significant local attention; Several opinion leaders/customers publicly critical	Some Concerns re: Competence; Difficult Demands	Conviction or regulatory finding of non-compliance with minor fine ("minor" meaning <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high/unprecedented amount for the industry).
Severe Fundamental threat to operating results; immediate senior management attention.	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced	Provincial media attention; most opinion leaders/customers publicly critical	Some loss of Credibility; Excessive Involvement;	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).
Worst Case Results threaten survival of company in current form; potentially full time senior management response until resolved.	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate	National media attention; opinion leaders/customers nearly unanimous in public criticism	General loss of Credibility; Intrusive Involvement;	Conviction with Incarceration of Staff
	same as Corporate Risk Matrix	same as Corporate Risk Matrix	same as Corporate Risk Matrix	same as Corporate Risk Matrix with addition of Minor1 Consequence.

Comments

Baseline Risk Statement Guidance

Investment Detail Field	Required Contents	Templates
Risk Statement	Provide a risk statement that contains a hazard/threat, a departure event, an asset and a consequence. The narrative will provide background information considered relevant to understanding and appreciating the noted concerns.	Given that [**HAZARD**], there is a possibility of [**DEPARTURE EVENT**] adversely impacting [**ASSET/OBJECTIVE**], which can result in [**CONSEQUENCE**]
Strength of Existing Controls	In absence of the proposed investment, what other controls are in place? Consider established corrective and demand programs, if applicable.	
Causal Factors	Describe the causal factors that contribute to the risk event.	
Context Statement	Document additional information that does not appear in the Risk Statement, including the "what, when, where, how and why" of the Risk by describing the risk indicators, circumstances, causal factors, uncertainties, and related issues. Provide data sources considered/consulted.	
Baseline Risk Assessment	Describe the consequence and likelihood of the Risk assessment and how was arrived at, including calculations.	
Risk Treatment	Describe what action, if any, should be taken to reduce the risk.	• Retain • Retain, but Change Mitigation • Increase • Avoid • Reduce likelihood • Reduce Consequence • Share

Hazards/Threats

- Fire
- Explosion
- Severe Weather
- Hazardous materials spill or release
- Mechanical breakdown
- Equipment condition
- Cyber Attack
- Physical Attack
- Theft and vandalism
- Obsolescence
- Inefficient processes
- Non-Compliance

Assets/Objectives at Risk

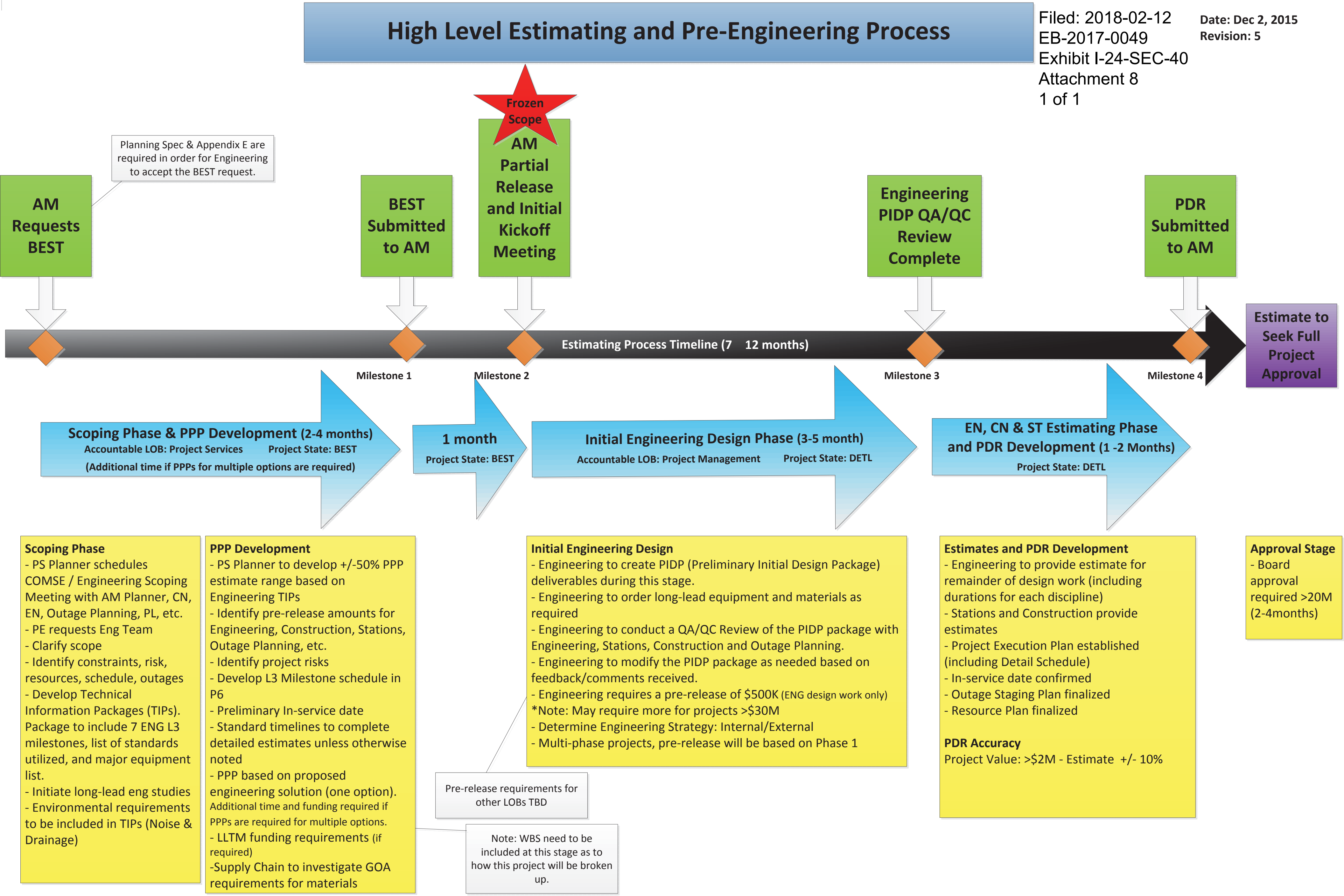
- People
- Power system facilities
- Customer Relationship
- Systems/Equipment
- Information Technology
- Operational performance
- Business Operations
- Financial profile
- Regulatory and legal obligations
- Environment
- Company Reputation

Consequences

- Workforce/Public Injuries
- Performance and reliability
- Erosion of customer goodwill
- Environmental release/contamination
- Financial loss
- Loss of Shareholder confidence
- Regulatory credibility
- Regulatory compliance
- Fines, penalties and sanctions

The above list is a sample only and is not intended to be exhaustive.

Date: Dec 2, 2015
Revision: 5



AIP Critical Inputs – Checklist

	AIP Investment Check	Applies to: Programs	Applies to: Projects	Verified?
Investment Details	Driver (Planning Portfolio) is correct and matches the driver of the AR specified in your alternative(s)	•	•	
	Investment Owner is populated and up-to-date	•	•	
	Investment Stage is “Short Term Planning”	•	•	
	Investment Segment and Category has been specified	•	•	
	Asset Optimal is selected as the “Recommended Alternative” (this is denoted by selecting the radio button beside the alternative name)	•	-	
	Single alternative demand based programs, or programs based on 3rd party contracts have been indicated using the appropriate checkbox on the Investment Details page	•	-	
	If an investment belongs to a common driver, “Tx%” has been specified on the Investment Details page in the field	•	•	
	If automatically compute removals has been checked, “Removal %” has been specified on the Investment Details page in the field			
	Attachment links to supporting documentation have been included	•	•	
Alternative Details	At least 3 alternatives exist for non-demand programs	•	-	
	Uninflated Dollar Reference year has been updated to ‘FY16’ for **each** alternative	•	•	
	Each program alternative contains cash flows for each year in the planning cycle, if applicable.	•	-	
	All alternatives that are part of the investment are deemed to be viable options if selected during optimization and have all been set to “Allow Alternative to be chosen as recommended”. Any obsolete alternatives have been brought to the attention of the AIP Team and have been deleted.	•	•	
	Alternative Start Date(s) reflects when the alternative is truly envisioned to start (e.g. if cash flows start in 2019, start date should be in 2019)	-	•	
	For shiftable projects – Earliest and Latest Start Dates are populated and are logical. Earliest Start Date occurs no earlier than the next calendar year.	-	•	

• Investment Check applies
- Investment Check does not apply

	If Project is not shiftable, rationale has been specified.	-	•	
	Estimate accuracy has been specified for Project Alternatives	-	•	
Alternative Forecasts	The AR(s) associated with your alternatives are valid (e.g. not completed, closed or cancelled) and the Service Provider indicated in AIP match the Service Provider in SAP	•	•	
	Removals, Capital Contributions, Recoveries have been captured where applicable and are entered as separate spend lines	•	•	
	IMPORTANT: If a Forecast Accomplishment was changed, a corresponding inconsequential cash flow change was made (e.g. $.01) and the draft forecast was submitted	•	•	
Alternative Milestone Dates	Planning Dates (e.g. Estimates, BCS, ISD) have been captured as Milestones and are in line with Estimate timelines as per Project Category guidelines	-	•	
	BCS Date and corresponding cash flow is logical (e.g. If EMPP date is Sept 30, 2017, there are no large cash flows in 2017)	-	•	
	No In-Service Date falls between December 16-31	-	•	
	All Milestone dates have been entered in the "Forecast Date" field with the exception of CCRA milestone which has been entered in the "Target Date" field.	-	•	
	Milestones **do not** reference an AR or Spend Group	-	•	
Risk Assessment(s)	Baseline risk justification has been completed for each risk on the Investment Details page	•	•	
	Risk Assessments have been completed for **each** Alternative	•	•	
	Residual Risk comments have been entered describing how the probability/consequences have been derived for each risk in **each** alternative	•	•	
Workflow Approval	Investment has **successfully** been submitted for Workflow Approval (only applies to Short Term Planning investments).	•	•	

• Investment Check applies
- Investment Check does not apply

AIP Manager Check List Field Descriptions

Field Name	Description	Expected Input
Investment Objectives aligned to Corporate Strategy	I confirm that Investment Objectives have been reviewed and align with the Corporate Strategy and a description of this alignment has been documented as part of the Investment Strategy.	Yes;No
Investment Development Supporting Documentation Included	I confirm that Supporting documentation has been included to justify investment development.	Yes;No;N/A
Defensible Risk Assessment Provided	I confirm that the risk assessment provided ties to the corporate strategy, features appropriate business values and is well documented including a full detailed baseline risk assessment.	Yes;No
Accomplishment Units Specified	I confirm that Accomplishments Units have been specified for each alternative level, if applicable (e.g., # of poles to be replaced each year)	Yes;No;N/A
Asset Analytics Utilization	I confirm that Asset Analytics (AA) was considered and/or used during Investment Development (if applicable) and any AA related data used is included in the AR Docs folder.	Yes;No;N/A
Other Data Sources Considered	Indicate any other Data Sources that have been considered	Free Text
Investment Categorization is Logical	I confirm that the Investment Segment and Categorization is indicated and accurately portrays the type of work to be completed.	Yes;No
Planning Timelines Are Logical	I confirm that Planning timelines have been reviewed and are realistic based on cash flows (e.g. time lapse between estimate released/required dates and full release date). Note that, this typically only applies to Projects.	Yes;No;N/A
Timing to Cash Flows Are Logical	I confirm that the in-service date aligns with the base-case cash flow (e.g. large cash flows do not occur after IS date, IS date does not fall after last year of cash flows, etc.) Note that, this typically only applies to Projects.	Yes;No;N/A
Service Provider Agreement With Alterna	I confirm that developed alternatives have been reviewed with the Service Provider and are viable. Note that, this typically only applies to Programs.	Yes;No;N/A
Estimate Provided by WPM	I confirm that a Class A, B, or C Estimate has been provided by Work Program Management and is included in the AR Docs folder. Note that, this only applies to Projects.	Yes;No;N/A
Alternatives Entered and Selectable	I confirm that alternatives have been entered and are all "selectable" (i.e., if the Optimizer chooses the alternative, it can be executed.) Note that, this typically applies to Programs.	Yes;No;N/A
Project Shift-able as Appropriate	I confirm that the project is shift-able as appropriate. Note that, this only applies to Projects	Yes;No;N/A
Gantt Chart Provided	I confirm that a Project Development Gantt Chart has been developed and is available on the Project Hub. (https://teams.hydroone.com/sites/TPD/TPD/hub/WBS%20Library/). Note that, this only applies to Projects.	Yes;No;N/A
Review Status	Indicates the review status of the particular investment. Not Started - Manager has not yet received a workflow notification In Progess - Workflow notification has been received and manager is currently reviewing the investment Reviewed - Manager has reviewed and "approved" the workflow in AIP	Not Started;In Progress;Reviewed

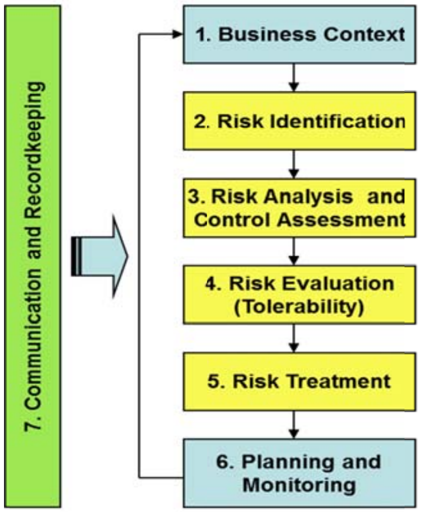
Manager checklist is to be completed for each investment on SharePoint. Please refer to the link below:
https://teams.hydroone.com/sites/120/1220/Lists/AIP%20Manager%20Checklist/AllItems.aspx

AIP Concepts and Definitions

AIP Term	Definition
Planning Portfolio / Driver	A grouping of investments. Planning Portfolios match the IM driver hierarchy. Ad-hoc Portfolios can be created for reporting and scenario analysis.
Investment Owner (IO) / Planner	Planners who manage investments including alternatives and assign assets, assess risk, benefits, timelines etc.
Portfolio Owner (PO) / Driver Owner	Managers and directors whose primary role is to: i) Review and approve investments alternatives proposed by Investment Owners via AIP workflow ii) Review and validate the optimization output
Parent Portfolio Owner	The highest level of approver for investments
AIP Team	Kevin Mancherjee and his team
Investment Optimization Manager	Responsible for the central AIP process coordination, running optimization and presenting results for validation, reporting and incorporation into the Business Plan
Investment	The best selection and timing of investment alternatives that maximize risk mitigated and benefit while satisfying financial and resource constraints.
Investment Type	Defines if the investment is a Project or Program. Depending on the Investment Type, different fields must be populated
	Tracks the stage of an investment from inception to completion. **IO's can only change the stage to Draft, Short Term Planning or Long Term Planning.** Other stages are updated by the AIP Team. **Draft** – Investment that is still in the development stage **Short Term Planning –** Investment to be included as part of the IPP (occurring within the planning horizon) **Long Term Planning -** Investment likely to occur outside the planning horizon (~6 years +) **Executing –** Investment that currently in-flight (limited to Projects, cash flows are loaded based on the multi-year LOB Forecast) **Complete – Investment is completed** Depending on the in the Investment Stage, different field must be populated
Alternative	Different possibilities for addressing the investment need. Investments may have one or more Alternative An Alternative will have an alternative start date, forecast, risk mitigation, milestones and benefits (optional). **Each Investment must have at least one Alternative**. As part of Optimization, the **choice of Alternative can be changed in order to maximize value**
Forecast	Refers to the area in AIP where you enter the **costs and units** (if applicable) associated with an Alternative. Forecasts will be different for each alternative.
Forecast Accomplishment	Refers to the units of accomplishment (e.g. # of poles, # of breakers, etc.) that are to be completed each year. Forecast Accomplishments will differ for each alternative.

Activity	Used to denote a specific Asset Type (e.g. 230 Kv Breakers), if applicable. Used in combination with Forecast Accomplishment.
Spend Line	Refers to the cost associated with an alternative. It is possible to have multiple spend lines within an alternative.
Spend Group	A bucket used to group similar spend lines and forecast accomplishments
Benefits	Refers to the area in AIP where financial benefits (e.g. FTE Savings) are entered for each Alternative.
Milestones	A Milestone is a key date to be captured for each Alternative and typically applies to Project Investments. Milestones will shift when the Alternative Start Date is modified. Any or all of the following milestones can be entered: BEST Released Date BEST Required Date DETL Released Date DETL Required Date BCS Approval Date (EMPP date) ISD CCRA Date
Risk Mitigation	Refers to the area in AIP where Risk Assessments are entered. Risk mitigation must be entered for each Alternative.
AIP Risk Consequence Table	Table of outcomes used by Investment Owners to aid in completing risk assessments. See: Link to AIP Risk Consequence Table
AIP Risk Matrix	The Risk Matrix residing within AIP. Combines consequence and probability. “Red Zone” is defined as a level of risk that is unacceptable to the company. It is not recommended that any alternative be proposed if any Business Value is identified with residual risk in the ‘red’ area of the Risk Consequence Table.
Baseline	The risk of doing nothing over time (in terms of base probability and base consequence)
Base Risk	The risk value from the AIP Risk Matrix, related to the baseline probability and consequence
Asset Impact	1. The result of making the investment (in terms of probability and consequence) 2. The fields in AIP where risk levels are entered
Residual Risk/Impact	The risk that remains after making the investment, represented by the value from the AIP Risk Matrix (the difference between the baseline risk and the risk mitigated)
Mitigated Risk	The reduction in risk from making the investment (represented by the value from the AIP Risk Matrix)
Value	The calculated value of an investment’s alternative, based on Benefits and Mitigated Risk.
Dependency	Links two investments that need to be approved/shifted together. Please contact AIP Team to create a dependency.
Optimizer	The AIP tool function that determines the best selection and timing of investment alternatives, maximizing risk mitigation and financial benefits, and satisfying the financial constraints and dependencies. It is run by the Investment Optimization Manager (IOM).
Corporate Values (weights)	Safety (20%) Reliability (15%) Customer (20%) Productivity (15%) Employees (10%) Environment (10%) Shareholder Value (10%) Note: Financial Benefits are calculated as 15% in addition to the weighted values.

Risk Assessment Framework



Key Terms

Risk – Effect of Uncertainty on Objectives
Risk Tolerance - organization's or stakeholder's readiness to bear the risk
Hazard – The current, fact-based situation or environment that is causing concern, doubt, anxiety or uneasiness.
Departure Event – occurrence or change of a particular set of circumstances
Consequence – outcome of an event affecting objectives (impact/magnitude)
Risk Treatment – process to modify risk
Control – measure that is modifying risk
Residual Risk – the risk that remains after controls are taken into account

AIP Risk Matrix

Consequence →

Probability	Minor1	Minor2	Minor3	Minor4	Minor5	Moderate	Major	Severe	Catastrophic
Very Likely	75	200	500	1,250	3,000	7,500	20,000	50,000	150,000
Likely	38	100	250	625	1,500	3,750	10,000	25,000	75,000
Medium	15	40	100	250	600	1,500	4,000	10,000	30,000
Unlikely	5	12	30	75	180	450	1,200	3,000	9,000
Remote	1	2	5	13	30	75	200	500	1,500
Unexpected	0	0	0	0	0	0	0	0	0

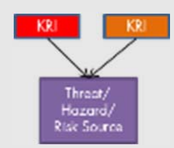
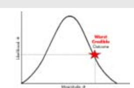
Risk Level: Low | Medium | High

Likelihood Guidance

Likelihoo Scale	Expectation of Event Frequency in years	Probability in Planning Period (5 years)
Very Likely	**>**1 in 2	**>** 95%
Likely	1 in 2 ***to*** 1 in 5	95% **to** 65%
Medium	1 in 5 ***to*** 1 in 20	65% **to** 25%
Unlikely	1 in 20 ***to*** 1 in 100	25% ***to*** 5%
Remote	1 in 100 ***to*** 1 in 500	5% ***to*** 1%
Unexpected	**<**1 in 500	**<** 1%

Module 3B:
Sunflower Cove Case Studies

Baseline Risk Assessment Documentation

Investment Detail Field	Required Contents	Templates	
Risk Statement	Provide a risk statement that contains a hazard/threat, a departure event, an asset/objective and a consequence. The narrative will provide background information considered relevant to understanding and appreciating the noted concerns.	Given that [**HAZARD**], there is a possibility of [**DEPARTURE EVENT**] adversely impacting [**ASSET/OBJECTIVE**], which can result in [**CONSEQUENCE**] 	
		Hazard: The **current, fact-based situation** or environment that is causing concern, doubt, anxiety or uneasiness.	**Departure Event:** Occurrence or **change of a particular set of circumstances**; unlike the Hazard Condition, the Departure Event is a statement about what might occur at a future time.
		Asset/Objective: The primary resource/element that is potentially impacted by the risk.	**Consequence:** Description of the credible outcome of an event affecting the company's objectives (impact/magnitude).
Strength of Existing Controls	In absence of the proposed investment, what other controls are in place? Consider established corrective and demand programs, if applicable.		
Context Statement	Document additional information that does not appear in the Risk Statement, including the "what, when, where, how and why" of the Risk by describing the risk indicators, circumstances, causal factors, uncertainties, and related issues. Provide data sources considered/consulted.		
Baseline Risk Assessment	Describe the consequence and likelihood of the Risk assessment and how was arrived at, including calculations.		
Risk Treatment	Describe what action, if any, should be taken to reduce the risk.	• Retain • Retain, but Change Mitigation • Increase	• Avoid • Reduce likelihood • Reduce Consequence • Share

Sunflower Cove Water – Consequences and Likelihood

	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
Reliable supply – Water not supplied	>75,00m^3	30,000-75,000m^3	10,000 – 30,000m^3	1,000 – 10,000m^3	<1,000m^3
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

Rating	Likelihood Scale	Expectation of Event Frequency in years	Probability in Planning Period (5 years)
5	Very Likely	>1 in 2	> 95%
4	Likely	1 in 2 to 1 in 5	95% to 65%
3	Medium	1 in 5 to 1 in 20	65% to 25%
2	Unlikely	1 in 20 to 1 in 100	25% to 5%
1	Remote	<1 in 100	< 5%

Case Study 1: New Development

Scenario

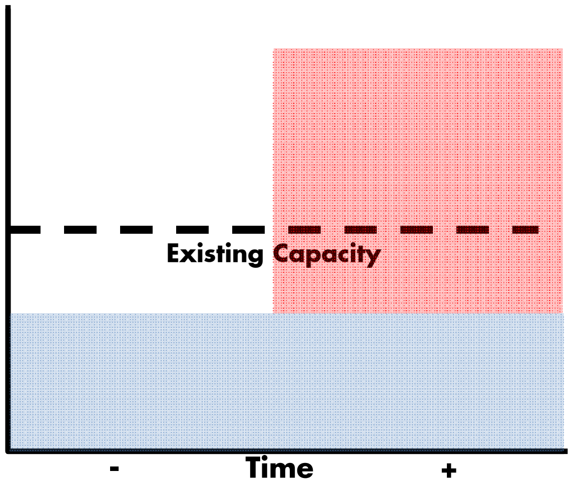
- A large company has noted its interest to develop a new Water and Amusement Park in Sunflower Cove because of its location on a major highway.
- The company has indicated that the waterpark will rely on city water supply and require a peak supply of water of 200m^3 per hour for 6 hours/day.
- Based on existing infrastructure in the area, and other customer requirements (100m^{3}per hour), Sunflower Cove can supply the new customer with, at most, 50m^3 per hour.
- Municipal bylaws state that Sunflower Cove must service new customers with water supply.
- The mayor's brother has recently been named VP of Business Development for the Water Park.

Recent Experience

- Because of its "prime location," Sunflower Cove has been approached by 8 theme parks in the last 10 years; despite strong proposals and sound local support, none of the proposals have been developed.
- Over that last 10 years, there have been 5 potential large customers per year that have announced plans to relocate to Sunflower Cove; only 2 of the potential customers have actually established operations.

Case Study: New Development (cont'd)

Risk = **Probability** ✖ **Consequence** ✖ **Mitigation Factor / Redundancy**



Risk Statement

Given that ,
there is a possibility that
will adversely impacting ,
which can result in

Likelihood Assessment

Consequence Assessment

Sunflower Cove Water – Consequence Table

	5 **Catastrophic**	4 **Severe**	3 **Major**	2 **Moderate**	1 **Minor**
Reliable supply – Water not supplied	>75,00m^3	30,000-75,000m^3	10,000 – 30,000m^3	1,000 – 10,000m^3	<1,000m^3
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

New Development

	1 Minor	2 Moderate	3 Major	4 Severe	5 Catastrophic
Very Likely >1 in 2 years					
Likely 1 in 2 to 1 in 5 years					
Medium 1 in 5 to 1 in 20 years					
Unlikely 1 in 20 to 1 in 100 years					
Remote 1 in 100 to 1 in 500 years					
Unexpected Less than 1 in 500 years					

Case Study: Asset Renewal

Scenario

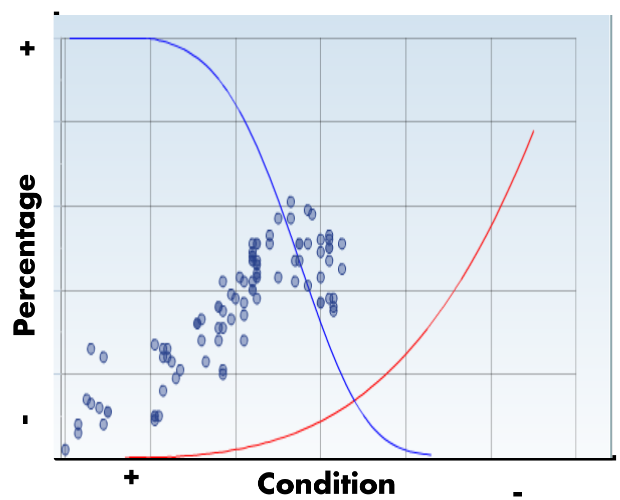
- The city of Sunflower Cove has approximately 6,000 km of water mains, divided into approximately 6,000 segments.
- Sunflower Cove grew rapidly during the 1950s and 1960s and considerable infrastructure was built to accommodate the growth.
- Approximately 2,000 km of ductile iron water mains were built during this time, a medium which has a typical service life of 50 years.
- Recent condition assessment and infrared studies have shown that the structural integrity of the 60 year old ductile iron constructed "trunk", serving a number of major customers that relies on a the trunk for consumption, heating, and cooling, is deteriorating.

Recent Analysis

- Citywide, the city experiences approx. 1,300 water main segment breaks per year.
- Over the last 5 years, 65% of failures occurred in ductile iron pipes, greater than 50 years old that were rated in poor condition prior to their failure.
- Most breaks are repairable, however about 5% of failures are considered catastrophic and require full replacement.

Case Study: Asset Renewal (cont'd)

Risk = **Probability** ✖ **Consequence** ✖ **Mitigation Factor / Redundancy**



Risk Statement

Given that [],
there is a possibility that []
which will adversely impact [],
which can result in []

Likelihood Assessment

Consequence Assessment

Sunflower Cove Water – Consequence Table

	5 Catastrophic	4 Severe	3 Major	2 Moderate	1 Minor
Reliable supply – Water not supplied	>75,00m³	30,000-75,000m³	10,000 – 30,000m³	1,000 – 10,000m³	<1,000m³
Public Safety	Public Injuries (with Sunflower Cover at fault)	Fatality or Major Permanent Disability	Significant Increase in Number of Injuries	Moderate Increase in Number of Injuries	Small Increase in Number of Injuries
Customer Satisfaction	Numerous large customers plan to relocate, with Sunflower Cove Water as a reason why	Industry associations step up lobbying efforts for stricter penalties	One "large" customer experiences significant losses	Increase in number of customer complaints	Less than planned improvement in customer satisfaction survey results
Public Profile	National media attention	Regional media attention	Significant local attention	Credible letter(s) to Mayor/Town Council	Credible letter(s) to Senior Management
Compliance	Conviction with incarceration of staff	Conviction or a municipal finding of non-compliance with major fine (>30% of max amount)	Conviction or a municipal finding of non-compliance with minor fine (<30% of max amount)	Municipal order, and/or a financial sanction that is small	Warning

Asset Renewal

	1 Minor	2 Moderate	3 Major	4 Severe	5 Catastrophic
Very Likely >1 in 2 years					
Likely 1 in 2 to 1 in 5 years					
Medium 1 in 5 to 1 in 20 years					
Unlikely 1 in 20 to 1 in 100 years					
Remote 1 in 100 to 1 in 500 years					
Unexpected Less than 1 in 500 years					

Assumption – Do Nothing/Baseline Risk Assessment

Case Study 1: New Development

Risk Statement	Consequence Assessment	Likelihood Assessment
Assumption – Risk of not connecting Waterpark *Business Value: Compliance* Given that municipal bylaw requires provision of service to new customers, there is a possibility that failing to connect the Waterpark will adversely impact Sunflower Cove Water's regulatory profile, which can result in a finding of non-compliance.	**Stated:** Municipal bylaws state that Sunflower Cove must service new customers with water supply. **Assessment:** It is unclear what penalties may result from non-compliance with Municipal Bylaws; at the low end and municipal order **(Moderate)** is likely with a possibility of an associated fine/penalty **(Major-Severe)**	**Assumption:** Likelihood of incident is based on likelihood of customer connecting. Large Customer Connections: last 10 years, there have been 50 potential connections, but only 2 have materialized. Incident Rate: 2 customer connections/ 50 potential connections = 1/25 **Unlikely**
Assumption – Risk of not connecting Waterpark *Business Value: Public Profile* Given that a Waterpark locating in Sunflower Cove may create jobs and generate tourism, there is a possibility that failing to connect the Waterpark will adversely impact Sunflower Cove Water's public profile, which can result in negative local or regional media attention.	**Stated:** The Mayor's brother is an executive of the Waterpark. **Assumed:** A new Waterpark will create jobs and generate tourism interest in Sunflower Cove. **Assessment:** If Sunflower Cove Water is seen as a barrier to economic development/tourism, it is conceivable that Waterpark may leverage its political connections and send credible letters to the mayor **(Moderate)**. Depending on the scale of economic development/tourism, residents may be vocal and gain support through local or regional media coverage **(Major – Severe)**.	
Assumption – Risk of connecting Waterpark *Business Value: Reliability* Given that there the existing infrastructure has insufficient capacity to supply all of the Waterpark's requirements, there is a possibility that connecting the Waterpark will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in water not supplied.	**Stated:** Waterpark requires 200m^3 of water per hour for 6 hours/day but there is only 50 m^3 of available capacity. **Assumed:** The Waterpark will operate 365 days per year. **Assessment:** There is an hourly capacity deficiency of 150m^3; at 6 hours per day and 365 days of operation per year, there is a total capacity shortfall of 328,500 m^3 per year **(Catastrophic)**.	
Assumption – Risk of connecting Waterpark *Business Value: Customer Satisfaction* Given that there the existing infrastructure has insufficient capacity to supply all of the Waterpark's requirements, there is a possibility that connecting the Waterpark will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in deteriorating customer satisfaction	**Stated:** Waterpark requires 200m^3 of water per hour for 6 hours/day but there is only 50 m^3 of available capacity; there are "other" customers relying on existing infrastructure. **Assumed:** If there is insufficient capacity to serve all demand, it is possible that service to all customers (including legacy ones) may deteriorate. **Assessment:** If service to existing customers deteriorates, it is conceivable that there could be an increase in customer complaints **(Moderate),** depending on the sensitivity of customer equipment/processes to a consistent level of service, a customer could experience loses as a result of deteriorated service **(Major)**.	
Assumption – Risk of connecting Waterpark	**Stated:** Waterpark requires 200m^3 of water per hour for 6 hours/day but there is only 50 m^3 of	

Business Value: Public Profile Given that there the existing infrastructure has insufficient capacity to supply all of the Waterpark's requirements, there is a possibility that connecting the Waterpark will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in deteriorated service levels and negative media attention.	available capacity; there are "other" customers relying on existing infrastructure. **Assumed:** If there is insufficient capacity to serve all demand, it is possible that service to all customers (including legacy ones) may deteriorate. **Assessment:** If service to existing customers deteriorates, it is conceivable that legacy customers or the Waterpark could be vocal about the level of service which could result in negative local or regional media coverage (**Moderate** to **Major**).	

Case Study 2: Asset Renewal

Assumption – Risk of not replacing pipe *Business Value: Safety* Given that condition assessment and infrared surveys show that the ductile iron pipe has deteriorated, there is a possibility that a critical, high volume pipe segment may fail catastrophically will adversely impact Sunflower Cove Water's public safety profile, which can result in public safety hazards.	**Stated:** The condition of the trunk is deteriorating; a number of major customers rely on the trunk for consumption, heating, and cooling. **Assumed:** If several major customers are served by this trunk for core services (consumption, heating, cooling), than the trunk is likely located in a high traffic area; any significant break could present street level public safety hazards or present challenges from a health and wellbeing perspective if a break were to occur in the middle of winter or summer. **Assessment:** Scenario could result in a small to moderate increase in injuries/incidents (**Minor to Moderate**).	**Likelihood of Segment Break (System Wide)** 1300 segment breaks/6000 segments =0.21 breaks/segment **Likely (1 in 2 to 1 in 5)** **Likelihood of Segment Break (Ductile Iron)** 0.65 x 1300 segment breaks/2000 segments =0.42 breaks/segment **Likely (1 in 2 to 1 in 5)**
Business Value: Reliability Given that condition assessment and infrared surveys show that the ductile iron pipe has deteriorated, there is a possibility that a critical, high volume pipe segment may fail catastrophically will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in water not supplied.	**Stated:** The condition of the trunk is deteriorating; a number of major customers rely on the trunk for consumption, heating, and cooling. 5% of failures are considered catastrophic. **Assumed:** The description of a failure as being catastrophic ties to the catastrophic reliability consequence. **Assessment: (Catastrophic)**.	**5% of failures are considered catastrophic** **Unlikely - Medium**
Business Value: Customer Satisfaction Given that condition assessment and infrared surveys show that the ductile iron pipe has deteriorated, there is a possibility that a critical, high volume pipe segment may fail catastrophically will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in deteriorating customer satisfaction.	**Stated:** The condition of the trunk is deteriorating; a number of major customers rely on the trunk for consumption, heating, and cooling. **Assumed:** Customers value a reliable, unrestricted supply. **Assessment:** If supply to customers is restricted/cut off there may be an increase in the number of customer complaints **(Moderate)**.	**Likelihood of Segment Break (System Wide)** 1300 segment breaks/6000 segments =0.21 breaks/segment **Likely (1 in 2 to 1 in 5)** **Likelihood of Segment Break (Ductile Iron)** 0.65 x 1300 segment breaks/2000 segments =0.42 breaks/segment **Likely (1 in 2 to 1 in 5)**

Business Value: Public Profile Given that condition assessment and infrared surveys show that the ductile iron pipe has deteriorated, there is a possibility that a critical, high volume pipe segment may fail catastrophically will adversely impact Sunflower Cove Water's ability to provide a reliable supply of water to customers, which can result in deteriorated service levels and negative media attention.	**Stated:** The condition of the trunk is deteriorating; a number of major customers rely on the trunk for consumption, heating, and cooling. **Assumed:** Customers value a reliable, unrestricted supply. **Assessment:** If service to existing customers is disrupted and critical functions are inhibited, customers may be in vocal opposition which could result in negative local or regional media coverage (**Moderate** to **Major**).	**Likelihood of Segment Break (System Wide)** 1300 segment breaks/6000 segments =0.21 breaks/segment **Likely (1 in 2 to 1 in 5)** **Likelihood of Segment Break (Ductile Iron)** 0.65 x 1300 segment breaks/2000 segments =0.42 breaks/segment **Likely (1 in 2 to 1 in 5)**

AIP Tool Training Exercises

Create New Project - Dx

EXERCISE 1 – CREATE NEW INVESTMENT

Joe the Planner works in the Distribution Planning group and has identified the need to replace switchgear at Ancaster West DS as it has deteriorated and is not up to current standards. Additionally, there is a need to co-ordinate with another customer's system upgrades and incorporate reconfiguration of their supply. Joe would like to document this investment need in AIP so that it can be considered for inclusion in the 2017 – 2022 Investment Plan.

If at any point you get stuck, refer to **AIP005587** which contains a completed example of the exercises below. **Note that, you can copy and paste the information below – it was emailed to you prior to this training session.**

<u>**Instructions**</u> *(AIP Tool Training Manual Reference: Page 23 – 33)*

1. Create a new investment using the Investment Template "Dx Capital Project Template". **Note the AIP Code as you will be using this investment for the remaining exercises.**

2. Populate the Investment Details based on the information below. Leave any fields that are not included in the input sheet below blank.

3. Attach a link

Investment Header	
Investment Name	Ancaster West DS Upgrade – **your name**
Investment Owner	**your name**
Investment Stage	Short Term Planning
Planning Portfolio	N.D.C.1.100 – Capital Investment Driver
Alternatives	
Allow Alternative to be shifted	Checked
Earliest Start Date	01/01/2017
Latest Start Date	01/01/2019
Investment Attributes	
Investment Strategy	Replace switchgear that has exceeded its expected service life and is no longer up to standard as well as associated protections. There is also a need to meet the customer's requirement to coordinate with their system upgrades and incorporate reconfiguration of their supply.
Customer Relationship Code	01 – Agreement (future/firm)
Nature of Customer Commitment	CCRA to be developed. Customer is Toronto Hydro.
Area	Greater Toronto Area
Sourcing Model	1 – Internal
Project Development Category	Category 1
Value Card	03 – None
Allocations	
Tx %	0%
Automatically Compute Removals	Checked
Removal %	20
OEB	
OEB Discretionary	OEB Non-Discretionary
EA Status	Not Required
OEB Section 92 Status	Not Required
Station Centric Asset Reductions (net number of units removed as a result of investment)	
# of Breaker Reductions	0

# of Transformer Reductions	0
Baseline Risk Justification – Customer	
Risk Statement – Customer	Given that Toronto Hydro needs to perform system upgrades that rely on our undertaking of this investment, not moving forward with this investment may prevent them from performing their upgrades which may lead to lower customer satisfaction scores.
Strength of Existing Controls – Customer	None.
Causal Factors – Customer	Customer requirements not provided in a timely manner.
Context Statement – Customer	
Baseline Risk Assessment – Customer	The Baseline Consequence was arrived at by utilizing the Asset Analytics to AIP Risk Assessment Template which has been attached for reference. In addition, historical customer satisfaction scores were reviewed in cases where a customer requirement was not addressed and were consistent with the "Moderate" customer consequence provided in the risk consequence table.
Risk Treatment – Customer	Reduce likelihood and consequence of baseline risk by addressing customer requirement.
Baseline Risk Justification – Reliability	
Risk Statement – Reliability	Given that Switchgear has surpassed expected service life, there is a possibility of failure which would adversely impact station reliability which could result in unsupplied energy.
Strength of Existing Controls – Reliability	Demand programs to deal with unexpected asset failures.
Causal Factors – Reliability	Deferred investment, asset strategy did not address asset need before EOL.
Context Statement – Reliability	Based on maintenance history it is evident that there have been more corrective orders than average on an asset of this type and age. Additionally, Asset Analytics data revealed that the majority of candidate assets for replacement have Demographic Risk Factor scores of 80-100 placing them in the poor category.
Baseline Risk Assessment – Reliability	The Baseline Consequence was arrived at by utilizing the Asset Analytics to AIP Risk Assessment Template which has been attached for reference.
Risk Treatment – Reliability	Reduce likelihood and consequence of baseline risk by replacing obsolete assets
Baseline Risk Justification – Safety	
Risk Statement – Safety	Given that Switchgear has surpassed expected service life and is in a deteriorated condition, there is a possibility that it no longer has the ability to withstand electrical faults, adversely impacting healthy in safety, which can result in injuries
Strength of Existing Controls – Safety	Personal Protective Equipment or do not maintain asset
Causal Factors – Safety	Poor design and lack of manufacturer support for parts.
Context Statement – Safety	Visual inspection and diagnostic testing has also revealed that this equipment has deteriorated and is no longer safe to maintain.
Baseline Risk Assessment – Safety	The Baseline Consequence and Probability was arrived at by reviewing history of other H&S issues that have been caused by switchgear of this vintage and condition.
Risk Treatment – Safety	Reduce likelihood and consequence of baseline risk by replacing obsolete assets

Attachments	
New Link	https://teams.hydroone.com/sites/120/1250/SitePages/Home.aspx
Description	AR Docs

EXERCISE 2 – EDIT ALTERNATIVE DETAILS, FORECASTS AND MILESTONES

Now that Joe has created an investment, he wants to capture how we will address the investment need in an alternative. Specifically, he wants to specify when the investment will start, how much it will cost and key project milestones.

Instructions *(AIP Tool Training Manual Reference: Page 36 – 55)*

1. Edit the Alternatives details to specify when the Project will start

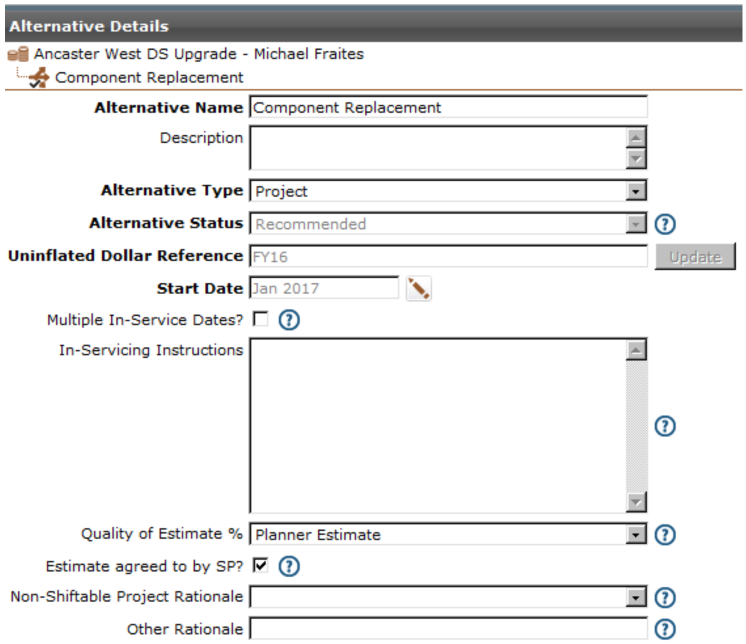
2. Populate the Alternative Forecast and Milestones with the following information:

Alternative Details	
Alternative Name	Component Replacement
Alternative Type	Project
Uninflated Dollar Reference	FY16
Start Date	01/01/2017 (Choose the option: "Do not shift cashflows" when prompted)
Multiple In-Service Dates?	Unchecked
Quality of Estimate %	Planner Estimate
Estimate agreed to by SP?	Checked

Alternative Costs							
Group Name	**Account**	**AR**	**Organization**	**2017 ($K)**	**2018 ($K)**	**2019 ($K)**	**2020 ($K)**
AR Placeholder 2	DXCAP	AR2	203	450	2,000	4,000	1,000
AR Placeholder 2	DXCON	AR2	203	-100	-100	-100	-100

Alternative Milestones						
Code	**Name**	**Target Date**	**Forecast Date**	**Actual Date**	**AR**	**Spend Group**
BESTREL	BEST Released Date		01/20/2017			
BESTREQ	BEST Required Date		05/12/2017			
DETLREL	DETL Released Date		05/18/2017			
DETLREQ	DETL Required Date		09/01/2017			
BCS	Business Case Approval Date		12/13/2017			
ISD	In – Service Date		11/30/2020			
CCRA	Capital Cost Recovery Agreement	11/30/2020				

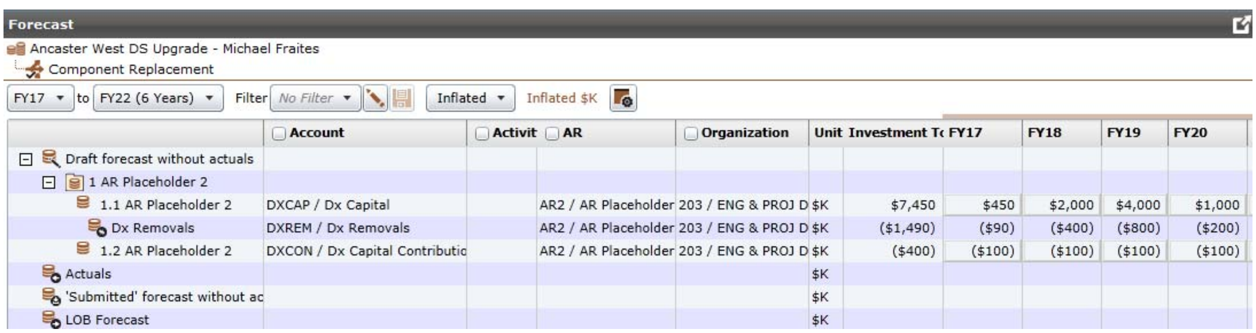
EXERCISE 2 (COMPLETED INPUT)



Alternative Details

Ancaster West DS Upgrade - Michael Fraites
Component Replacement

Alternative Name	Component Replacement
Description	
Alternative Type	Project
Alternative Status	Recommended
Uninflated Dollar Reference	FY16 (Update)
Start Date	Jan 2017
Multiple In-Service Dates?	☐
In-Servicing Instructions	
Quality of Estimate %	Planner Estimate
Estimate agreed to by SP?	☑
Non-Shiftable Project Rationale	
Other Rationale	

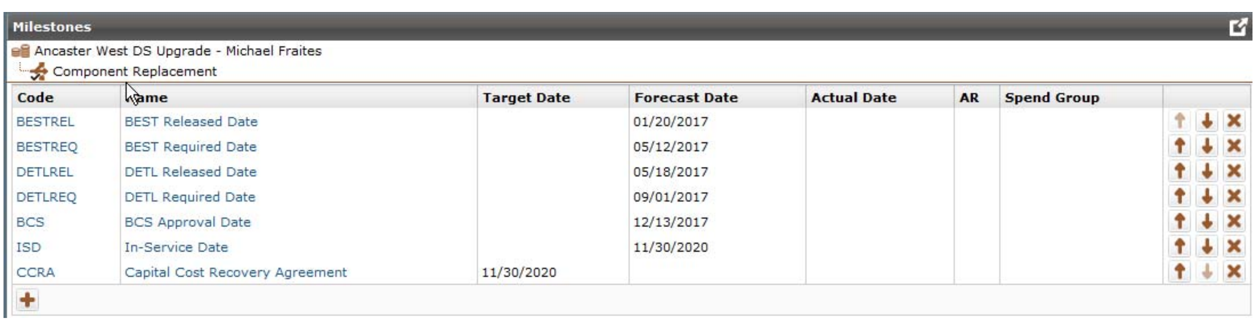


Forecast

Ancaster West DS Upgrade - Michael Fraites
Component Replacement

FY17 to FY22 (6 Years) Filter No Filter Inflated Inflated $K

	Account	Activit	AR	Organization	Unit	Investment To	FY17	FY18	FY19	FY20
Draft forecast without actuals										
1 AR Placeholder 2										
1.1 AR Placeholder 2	DXCAP / Dx Capital		AR2 / AR Placeholder	203 / ENG & PROJ D	$K	$7,450	$450	$2,000	$4,000	$1,000
Dx Removals	DXREM / Dx Removals		AR2 / AR Placeholder	203 / ENG & PROJ D	$K	($1,490)	($90)	($400)	($800)	($200)
1.2 AR Placeholder 2	DXCON / Dx Capital Contributio		AR2 / AR Placeholder	203 / ENG & PROJ D	$K	($400)	($100)	($100)	($100)	($100)
Actuals					$K					
'Submitted' forecast without ac					$K					
LOB Forecast					$K					



Milestones

Ancaster West DS Upgrade - Michael Fraites
Component Replacement

Code	Name	Target Date	Forecast Date	Actual Date	AR	Spend Group
BESTREL	BEST Released Date		01/20/2017			
BESTREQ	BEST Required Date		05/12/2017			
DETLREL	DETL Released Date		05/18/2017			
DETLREQ	DETL Required Date		09/01/2017			
BCS	BCS Approval Date		12/13/2017			
ISD	In-Service Date		11/30/2020			
CCRA	Capital Cost Recovery Agreement	11/30/2020				

EXERCISE 3 – COMPLETE RISK ASSESSMENT

Now that Joe has created his investment, documented his baseline risk justification and created an alternative to capture the costs associated with his investment, he would like to formally capture his baseline and residual risk assessment. Joe will be using the output of the Asset Analytics to AIP Risk Template to complete this assessment.

Instructions *(AIP Tool Training Manual Reference: Page 58 – 61)*

1. Enter a baseline and residual risk assessment for **Customer, Reliability** and **Safety** based on the information below.
2. Add a Residual Risk comment to at least one risk

Asset Condition Impact & Risk Mitigation

Ancaster West DS Upgrade - Michael Fraites

Component Replacement

FY17 to FY22

Attribute	FY17	FY18	FY19	FY20	FY21	FY22
AIP005587 Customer Dissatisfaction (Customer Risk)	Total Mitigated Risk: 16,537				Impact FY17	
Base Consequence	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate
Probability of Base Consequence	Unlikely	Unlikely	Unlikely	Medium	Medium	Medium
Base Risk	450	450	450	1,500	1,500	1,500
Residual Consequence	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate
Probability of Residual Consequence	Unlikely	Unlikely	Unlikely	Medium	Unexpected	Unexpected
Residual Risk	450	450	450	1,500	0	0
Mitigated Risk	0	0	0	0	1,500	1,500
AIP005587 Equipment Failure (Reliability Risk)	Total Mitigated Risk: 1,262				Impact FY17	
Base Consequence	Minor1	Minor2	Minor3	Minor3	Minor3	Minor3
Probability of Base Consequence	Unlikely	Unlikely	Medium	Medium	Medium	Medium
Base Risk	5	12	100	100	100	100
Residual Consequence	Minor1	Minor2	Minor1	Minor1	Minor1	Minor1
Probability of Residual Consequence	Unlikely	Unlikely	Unexpected	Unexpected	Unexpected	Unexpected
Residual Risk	5	12	0	0	0	0
Mitigated Risk	0	0	100	100	100	100
AIP005587 No HS Improvement (Safety Risk)	Total Mitigated Risk: 118,017				Impact FY17	
Base Consequence	Major	Major	Major	Major	Major	Major
Probability of Base Consequence	Likely	Likely	Likely	Likely	Likely	Likely
Base Risk	10,000	10,000	10,000	10,000	10,000	10,000
Residual Consequence	Major	Major	Major	Minor1	Minor1	Minor1
Probability of Residual Consequence	Likely	Likely	Likely	Unexpected	Unexpected	Unexpected
Residual Risk	10,000	10,000	10,000	0	0	0
Mitigated Risk	0	0	0	10,000	10,000	10,000

EXERCISE 4 – ROUTE INVESTMENT FOR WORKFLOW APPROVAL

Now that Joe has completed entering all the details that are relevant to his investment, he would like to submit it to his team lead and manager for Approval.

<u>Instructions</u> *(AIP Tool Training Manual Reference: Page 68 – 71)*

1. Validate your investment
2. Submit your investment for workflow approval based on the information below:

Workflow	
Comment	Please approve my investment
Reviewer 1	Aline Brodie

AIP Tool Training Exercises

Update Program Investment

EXERCISE 1 – CREATE NEW INVESTMENT / UPDATE INVESTMENT

Joe the Planner works in the Distribution Capital Station Sustainment group and would like to update his DS Station Refurbishment Program for the 2017 – 2022 Investment Planning Cycle so that it accurately reflects the asset need and clearly articulates the risk(s) of each Alternative.

If at any point you get stuck, refer to **AIP005585** which contains a completed example of the exercises below. **Note that, you can copy and paste the information below – it was emailed to you prior to this training session.**

Instructions *(AIP Tool Training Manual Reference: Page 23 – 33)*

1. Create a new investment by cloning the existing investment "**AIP005582 – TRAINING DS Station Refurbishment Program**" (creating a new program is for demonstration purposes only, typically you will only need to update the details of an existing program investment). **Note the AIP Code of your new investment as you will be using it for the remaining exercises. AIP Code ___________**

2. Populate the Investment Details based on the information below. Leave any fields that are not included in the input sheet blank.

3. Attach a link

Investment Header	
Investment Name	TRAINING DS Station Refurbishment Program - **your name**
Investment Type	Program
Investment Stage	Short Term Planning
Investment Owner	**your name**
Planning Portfolio	N.D.C.1.100 - Capital Investment Driver
Alternatives	
Allow Alternative to be shifted	Unchecked for all alternatives
Investment Attributes	
Investment Strategy	The strategy for this program is to refurbish all Distribution Stations with assets that are at a high risk of failure, and impact critical customers or a high number of customers. Station / asset risk are determined by asset condition, demographics, criticality, customer supply reliability and design deficiencies.
Plan Over Plan	Revised Unit Prices received for conventional DS Refurbishments.
Customer Relationship Code	03 – None (default)
Forecast Is Based on Historical Demand?	Unchecked
Forecast Is Based on Signed 3rd Party Contracts?	Unchecked
MFA	Unchecked
Reportable Unit	# of Stations
Unit Price Provided by SP?	Checked
Area	N/A
Asset Population	1052
Sourcing Model	1 - Internal
Project Development Category	Category 4
Value Card	01 - Existing
Allocations	
Removal %	7%
Automatically Compute Removals	Checked

Tx %	
OEB	
OEB Number	S59
Baseline Risk Justification - Customer	
Risk Statement - Customer	Given that many assets are at EOL, there is a possibility of failure adversely impacting Large and Mid-size customers, which can result in lower customer satisfaction scores.
Strength of Existing Controls - Customer	Corrective and Demand Programs exist to repair/replace components that fail prior to planned replacement.
Causal Factors - Customer	Deferred investment, asset strategy did not address asset need before EOL.
Context Statement – Customer	Customer complaints arise when transformer tap-changers fail to regulate voltage, resulting in customers experiencing high and low voltage situations and from frequent interruptions of equipment due to failing or failed station assets. This was evident after reviewing customer satisfaction scores of customers fed by the worst performing stations.
Baseline Risk Assessment - Customer	The Baseline Consequence was arrived at by analyzing customer satisfaction scores at the worst performing stations over the past 3 years vs. customer satisfaction scores of the best performing stations over the same period of time. Please refer to investment attachments for a full breakdown.
Risk Treatment - Customer	Reduce likelihood and consequence of baseline risk by replacing assets that are at EOL/in poor condition AND serve critical customers.
Baseline Risk Justification - Reliability	
Risk Statement - Reliability	Given that many assets are at EOL, there is a possibility of failure adversely impacting reliability, which can result in extended frequency and duration of outages.
Strength of Existing Controls - Reliability	Corrective and Demand Programs exist to repair/replace components that fail prior to planned replacement.
Causal Factors - Reliability	Deferred investment, asset strategy did not address asset need before EOL.
Context Statement – Reliability	The strategy for this program is based on information provided by Asset Analytics, Station Surveys, SAP (PNs, DRs) information and needs from other LOBs. The information compiled from the various sources is used as a factor in determining candidates for this program. Priority will be placed on addressing transformers and station structures that are beyond their expected service life and in unacceptable condition, and replacing breakers that are obsolete, and no longer supported by manufacturers in the event of failure.
Baseline Risk Assessment - Reliability	- 1000+ customers are fed from Dx stations. - 10-15 Class 1 transformer failures are expected per year. - 150+ failed or failing reclosers are expected per year. - 1-5 breaker failures are expected per year. Please refer to investment attachments for a full breakdown.
Risk Treatment - Reliability	Reduce likelihood and consequence of baseline risk by replacing obsolete assets
Baseline Risk Justification - Environment	
Risk Statement - Environment	Given that many station assets are at EOL and prone to leaking, there is a possibility of oil leaking offsite or into bodies of water, which can result in adverse impact to environment.
Strength of Existing Controls - Environment	Spill containment pits exist at some sites in addition to Corrective and Demand Programs that exist to repair/replace components that fail prior to planned replacement.
Causal Factors - Environment	Deferred investment, asset strategy did not address asset need before EOL.
Context Statement – Environment	Distribution Stations and associated assets are often located in urban areas, close

	to residential properties, schools, parks, private and public water supplies which may or may not provide a source of drinking water. Aged assets such as transformers that are in poor condition often have minor oil leaks on Hydro One property, and if the leaks are not controlled, can leak off-site into public bodies with moderate environmental impact.
Baseline Risk Assessment - Environment	Visual inspection and corrective maintenance order history have confirmed leaking of assets in candidate stations. In addition, consequences have been derived based on candidate stations geographical proximity to urban centers/bodies of water.
Risk Treatment - Environment	Reduce likelihood and consequence of baseline risk by replacing obsolete assets

Attachments	
New Link	https://teams.hydroone.com/sites/120/1250/SitePages/Home.aspx
Description	AR Docs

EXERCISE 2 – EDIT ALTERNATIVE DETAILS AND FORECASTS

Now that Joe has updated the investment details for his program, he wants to update the cash flows and accomplishment forecasts of each alternative as new unit prices ($2,400K/station) have been provided by Operations for conventionally designed stations. Specifically, he wants to add additional years of funding and accomplishments to the program and revise the costs for previous years. He has already updated the line items for iMDS units and therefore, does not need to update them as part of this exercise.

Instructions *(AIP Tool Training Manual Reference: Page 36 – 53)*

1. Update the Uninflated Dollar Reference year for each Alternative (Asset Optimal, Intermediate, Vulnerable) to FY16
2. Update the Forecast of each Alternative with the following information:

Alternative: Asset Optimal

Alternative Accomplishments / Costs ($K)										
Group Name	**Entity**	**Account**	**AR**	**Org**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
DS Station Refurbishment Program – Conventional Design	Forecast Accomplishment		AR1	203	31	31	31	31	31	31
DS Station Refurbishment Program – Conventional Design	Spend Line	DXCAP	AR1	203	74,400	74,400	74,400	74,400	74,400	74,400

Alternative: Intermediate

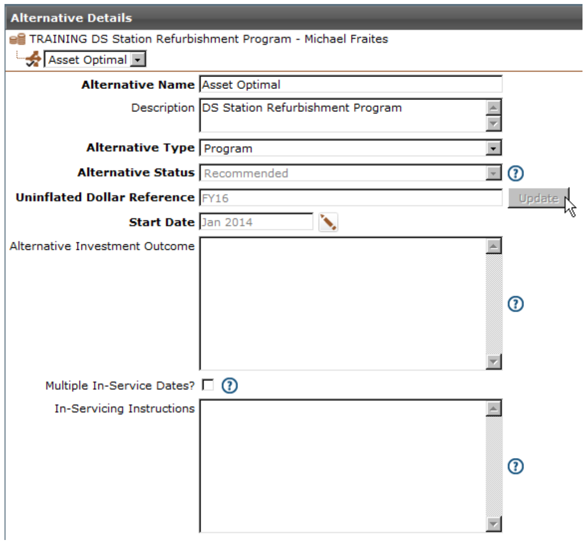
Alternative Accomplishments / Costs ($K)										
Group Name	**Entity**	**Account**	**AR**	**Org**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
DS Station Refurbishment Program – Conventional Design	Forecast Accomplishment		AR1	203	20	20	20	20	20	20
DS Station Refurbishment Program – Conventional Design	Spend Line	DXCAP	AR1	203	48,000	48,000	48,000	48,000	48,000	48,000

Alternative: Vulnerable

Alternative Accomplishments / Costs ($K)										
Group Name	**Entity**	**Account**	**AR**	**Org**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
DS Station Refurbishment Program – Conventional Design	Forecast Accomplishment		AR1	203	7	8	8	8	8	8
DS Station Refurbishment Program – Conventional Design	Spend Line	DXCAP	AR1	203	16,800	19,200	19,200	19,200	19,200	19,200

EXERCISE 2 (COMPLETED INPUT)

Uninflated Dollar Reference Year (should look the same for each Alternative)



Asset Optimal - Forecast

Forecast

TRAINING DS Station Refurbishment Program - Michael Fraites

Asset Optimal

FY17 to FY22 (6 Years) Filter No Filter Uninflated (Draft Only) Uninflated $K

	Account	Activity	AR	Organ	Unit	Investment Total	FY17	FY18	FY19	FY20	FY21	FY22
Draft forecast without actuals												
1 DS Station Refurbishment Program - Conventional Design												
Forecast Accomplishment			AR1 / AF	203 / ENC		287.00	31.00	31.00	31.00	31.00	31.00	31.00
1.1 DS Station Refurbishment Program	DXCAP / Dx		AR1 / AF	203 / ENC	$K	$612,261	$74,400	$74,400	$74,400	$74,400	$74,400	$74,400
Dx Removals	DXREM / Dx		AR1 / AF	203 / ENC	$K	($42,858)	($5,208)	($5,208)	($5,208)	($5,208)	($5,208)	($5,208)
2 DS Station Refurbishment - iMDS Units					$K	$83,796	$10,697	$12,480	$12,480	$12,480	$12,480	$12,480
Actuals					$K							

Intermediate - Forecast

Forecast

TRAINING DS Station Refurbishment Program - Michael Fraites

Intermediate

FY17 to FY22 (6 Years) Filter No Filter Uninflated (Draft Only) Uninflated $K

	Account	Activity	AR	Organ	Unit	Investment Total	FY17	FY18	FY19	FY20	FY21	FY22
Draft forecast without actuals												
1 DS Station Refurbishment Program - Conventional Design												
Forecast Accomplishment			AR1 / AF	203 / ENC		185.00	20.00	20.00	20.00	20.00	20.00	20.00
1.1 DS Station Refurbishment Program	DXCAP / Dx		AR1 / AF	203 / ENC	$K	$377,218	$48,000	$48,000	$48,000	$48,000	$48,000	$48,000
Dx Removals	DXREM / Dx		AR1 / AF	203 / ENC	$K	($26,405)	($3,360)	($3,360)	($3,360)	($3,360)	($3,360)	($3,360)
2 DS Station Refurb - iMDS Units					$K	$92,087	$10,697	$12,480	$12,480	$12,480	$12,480	$12,480
Actuals					$K							

Vulnerable - Forecast

Forecast

TRAINING DS Station Refurbishment Program - Michael Fraites

Vulnerable

FY17 to FY22 (6 Years) Filter No Filter Uninflated (Draft Only) Uninflated $K

	Account	Activity	AR	Organ	Unit	Investment Total	FY17	FY18	FY19	FY20	FY21	FY22
Draft forecast without actuals												
1 DS Station Refurbishment Program - Conventional Design												
Forecast Accomplishment			AR1 / AF	203 / ENC		82.00	7.00	8.00	8.00	8.00	8.00	8.00
1.1 DS Station Refurbishment Program	DXCAP / Dx		AR1 / AF	203 / ENC	$K	$164,829	$16,800	$19,200	$19,200	$19,200	$19,200	$19,200
Dx Removals	DXREM / Dx		AR1 / AF	203 / ENC	$K	($11,538)	($1,176)	($1,344)	($1,344)	($1,344)	($1,344)	($1,344)
2 DS Station Refurb - iMDS Units					$K	$83,796	$10,697	$12,480	$12,480	$12,480	$12,480	$12,480
Actuals					$K							

EXERCISE 3 – COMPLETE RISK ASSESSMENT

Now that Joe has updated his investment details, documented his baseline risk justification and updated his alternative forecasts, he would like to update his baseline and residual risk assessment for the **Asset Optimal** alternative. He has already updated his risk assessment for the other alternatives. Joe will be using the output of the Asset Analytics, SAP (DRs, PNs), Station Surveys and other data to document his risk.

<u>Instructions</u> *(AIP Tool Training Manual Reference: Page 55 – 62)*

1. Update the baseline and residual risk assessment for **Customer** and **Reliability** based on the information below within the **Asset Optimal** alterative (**hint:** only the FY21 and FY22 have changed in this example).
2. Add a new risk baseline and residual risk for **Environment** to the **Asset Optimal** alternative based on the information below.
3. Add a Residual Risk comment to at least one risk

Asset Optimal – Modification of Existing Risks

Asset Condition Impact & Risk Mitigation

TRAINING DS Station Refurbishment Program

Asset Optimal

FY17 to FY22

Attribute	FY17	FY18	FY19	FY20	FY21	FY22
AIP005582 - AIP000160 (Reliability Risk)	Total Mitigated Risk: 13,494					Impact FY14
Base Consequence	Minor3	Minor4	Minor4	Minor4	Minor4	Minor4
Probability of Base Consequence	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely
Base Risk	500	1,250	1,250	1,250	1,250	1,250
Residual Consequence	Minor3	Minor3	Minor3	Minor3	Minor3	Minor3
Probability of Residual Consequence	Very Likely	Likely	Likely	Likely	Likely	Likely
Residual Risk	500	250	250	250	250	250
Mitigated Risk	0	1,000	1,000	1,000	1,000	1,000
AIP005582 - AIP000160 (Customer Risk)	Total Mitigated Risk: 110,457					Impact FY15
Base Consequence	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate
Probability of Base Consequence	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely
Base Risk	7,500	7,500	7,500	7,500	7,500	7,500
Residual Consequence	Minor1	Minor1	Minor1	Minor1	Minor1	Minor1
Probability of Residual Consequence	Likely	Likely	Likely	Likely	Likely	Likely
Residual Risk	38	38	38	38	38	38
Mitigated Risk	7,463	7,463	7,463	7,463	7,463	7,463

Asset Optimal – Addition of New Risk

Attribute	FY17	FY18	FY19	FY20	FY21	FY22
AIP005585 - AIP000160 (Reliability Risk)	Total Mitigated Risk: 10,738					Impact FY14
AIP005585 - AIP000160 (Customer Risk)	Total Mitigated Risk: 110,457					Impact FY15
AIP005585 - Oil Spill (Environment Risk)	Total Mitigated Risk: 107,570					Impact FY17
Base Consequence	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate
Probability of Base Consequence	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely	Very Likely
Base Risk	7,500	7,500	7,500	7,500	7,500	7,500
Residual Consequence	Minor1	Minor1	Minor1	Minor1	Minor1	Minor1
Probability of Residual Consequence	Likely	Likely	Likely	Likely	Likely	Likely
Residual Risk	38	38	38	38	38	38
Mitigated Risk	7,463	7,463	7,463	7,463	7,463	7,463

EXERCISE 4 – ROUTE INVESTMENT FOR WORKFLOW APPROVAL

Now that Joe has completed entering all the details that are relevant to his investment, he would like to submit it to his team lead and manager for Approval.

<u>Instructions</u> *(AIP Tool Training Manual Reference: Page 68 – 70)*

1. Validate your investment
2. Submit your investment for workflow approval based on the information below:

Workflow	
Comment	Please approve my investment
Reviewer 1	Aline Brodie

School Energy Coalition Interrogatory # 41

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: 27

Interrogatory:

With respect to Hydro One's candidate capital investment prioritization criteria weighting score, please explain the relevance of including archiving and maintaining employee engagement. Please use examples to illustrate Hydro One's answer.

Response:

Hydro One is assuming the question contains a typographical error and that SEC meant "achieving and maintaining employee engagement," instead of "archiving and maintaining employee engagement."

The prioritization criteria used in the development of the DSP reflected Hydro One's Business Objectives at the time, which allows Hydro One to align its investment planning decision-making with its strategic context.

Hydro One sees value in building a culture of skill and ability, coupled with accountability to deliver best-in-class service to its customers. Hydro One believes that improved employee engagement leads to better performance results and that engaged employees are safe employees and are on front-line in delivering improved productivity and value for money to our customers.

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 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 EB-2013-0416 have been reported,

Please note that the values listed in 2017 are based on forecasts. Actuals will be made available at a later date.

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.

24-SEC-42

Please completed the shadded areas

	EB 2013 0416 Ex.D2 02 02 — LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $1M						EB 2017 0049							
1.0	**SUSTAINING CAPITAL (Exhibit D1, Tab 3, Schedule 2)**													
1.1	**Stations**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
S1	Transformer Spares and Replacements	18.0	18.4	17.9	21.2	21.6	20.4	7.6	1.9		*Refer to Exhibit B1-01-01.*			
S2	Mobile Unit Substations	4.6	3.6	3.7	3.6	3.7	0.3	0.9	4.4					
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	1.9					
S5	Recloser Upgrades	1.4	1.4	1.4	1.5	1.5	0.7	3.0	2.3					
S6	Demand Work	2.1	2.1	2.1	2.2	2.2	1.6	2.7	2.2					
S7	Station Refurbishments	34.6	39.0	40.0	44.5	45.2	58.9	48.9	29.1					
1.2	**Lines**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	81.0					
S9	Joint Use and Line Relocations	26.7	27.3	27.8	28.4	28.9	24.9	23.4	21.5					
S10	Pole Replacements	88.7	95.1	105.0	115.2	125.8	87.4	90.9	93.9					
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	12.1					
S13	Line Component Replacements	11.6	11.8	12.1	12.3	12.6	11.3	9.8	9.0					
S14	Submarine Cable Replacements	7.1	7.2	7.4	7.5	7.7	7.5	8.0	7.4					
1.3	**Meters**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
S15	Meter Upgrades	10.0	15.8	18.8	16.1	5.0	30.2	24.4	20.6					
S16	Meter Inventory Sustainment	4.6	4.8	5.0	5.2	5.5	3.6	14.0	6.1					
	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	294.0					
	Sustaining projects/programs less than $1M	2.0	0.0	0.0	0.0	0.0	1.4	1.3	3.9					
	Total Sustaining Capital (per Exhibit D1-3-1)	**308.2**	**335.2**	**359.7**	**380.4**	**383.5**	372.5	359.4	297.9					
2.0	**DEVELOPMENT CAPITAL (Exhibit D1, Tab 3, Schedule 3)**													
2.1	**Connections**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	108.3					
2.2	**System Capability Reinforcement**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	9.4					
D3	Upgrades Driven by Load Growth - Distribution System Modifications	9.0	9.2	9.4	9.1	8.8	13.6	10.8	3.5					
D4	Upgrades Driveb by Load Growth - Demand Investments	3.6	3.7	3.8	3.4	3.4	2.9	3.2	2.0					
D5	Asset Lifecycle Optimization and Operational Efficiency	8.1	9.7	8.9	4.2	4.5	4.9	8.3	6.3					
D6	Reliability Improvements	2.7	2.0	2.6	1.6	2.2	1.2	0.5	1.1					
D7	Orleans TS Capital Contribution	21.0	0.0	0.0	0.0	0.0	5.1	3.1	0.0					
D8	Red Lake TS Capital Contribution	1.8	0.0	0.0	0.0	0.0	0.3	0.1	0.7					
D9	Hanmer TS Capital Contribution	0.0	11.5	0.0	0.0	0.0	0.0	0.0	1.7					
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	3.6					
2.3	**Distribution Generation Connection**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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**	**2017F**	**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	136.6					
	Development projects/programs less than $1M	47.1	31.7	16.7	15.1	13.3	22.8	13.4	36.5					
	Total Development Capital (per Exhibit D1-3-1)	**223.3**	**206.3**	**207.7**	**183.5**	**199.1**	186.4	174.8	173.1					
3.0	**OPERATIONS CAPITAL (Exhibit D1, Tab 3, Schedule 4)**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
O1	Operating Compute Refresh	0.0	0.0	0.0	0.9	1.9	0.0	0.0	3.7					
O2	NOMS Refresh	0.0	1.4	0.0	0.0	0.0	0.0	0.0	1.8					
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	2.2					
	Summary	**2015**	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	7.7					
	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	7.7					
4.0	**CUSTOMER SERVICE CAPITAL (Exhibit D1, Tab 3, Schedule 5)**													
	Summary	**2015**	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
	*Total Customer Service projects/programs***	22.4	8.0	1.5	0.0	0.0	5.2	17.2	16.0					
	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	16.0					
	**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**	**2017F**	**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	7.9					
IT2	MFA Servers and Storage	7.1	9.3	8.0	5.3	5.3	6.1	1.9	9.4					
IT3	MFA PC and Printer Hardware	5.6	5.3	5.3	4.5	4.0	3.7	4.3	5.3					
IT4	MFA Telecom Infrastructure	2.7	2.9	2.5	2.8	2.9	1.1	1.9	2.5					
IT5	Field Workforce Optimization and Mobile IT	5.0	5.0	8.0	2.0	2.0	9.9	20.6	11.1					
IT6	Customer Experience	5.0	1.0	4.0	1.0	3.0	0.3	5.9	6.2					
IT7	Information Rights Management	0.0	0.0	0.0	2.5	2.5	0.0	0.9	0.0					
IT8	Enterprise Analytics	2.0	2.0	2.0	0.0	0.0	2.2	0.9	0.0					
IT9	Corporate Support Optimization	0.0	3.0	0.0	3.0	0.0	1.3	2.4	0.0					
IT10	Engineering Design Transformation	0.0	0.0	0.0	4.0	3.0	0.0	0.4	3.1					
IT11	Enterprise GIS	2.0	1.0	2.1	0.0	1.0	0.0	0.6	1.2					
5.2	**Common Corporate Costs and Other**													
		2015	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	34.8					
C3	Transport and Work Equipment	54.5	62.5	56.7	62.9	59.0	65.9	64.5	61.1					
C4	Service Equipment	9.1	7.9	7.9	7.0	7.0	7.0	6.2	5.7					
C5	Security Infrastructure Capital	1.0	1.0	1.1	1.1	1.1	0.0	1.3	1.1					
1.3	**Meters**													
	Summary	**2015**	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	149.4					
	Common Corporate Costs and Other projects/programs less than $1M	9.2	9.5	9.4	9.6	9.8	12.9	3.6	1.5					
	(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	150.9					
	Costs Allocated to Distribution	**2015**	**2016**	**2017**	**2018**	**2019**	**2015A**	**2016A**	**2017F**	**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	97.6					

School Energy Coalition Interrogatory # 43

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

Interrogatory:

For each major asset and asset type, please provide how many there are, and a breakdown of their condition. For example, please provide the number of oil reclosers in Hydro One's distribution system, and how many are in excellent, very good, good, poor, and very poor condition.

Response:

Please refer to interrogatory response Exhibit I-24-AMPCO-23.

School Energy Coalition Interrogatory # 44

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

Interrogatory:

For each asset type, please provide a table showing the number of assets in each condition risk/assessment category.

Response:

Please refer to interrogatory response Exhibit I-24-AMPCO-23.

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.

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.

School Energy Coalition Interrogatory # 47

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:

B1-02-01 Page: 12

Interrogatory:

For each year between 2014 and 2022, please provide the percentage of capital spending that is undertaken by third-parties. Please also breakdown which activities they undertaken and which category of spending they fall under.

Response:

Hydro One uses specialized service providers to complement its field forces (vac trucks, rock drilling, etc.) but does not currently contract out entire capital work packages/projects to be undertaken by third parties. Hydro One has had one exception in 2017 where it entered into a service agreement with the Power Workers Union to facilitate contracting out a small number of CDMA meter replacements to an appropriate third party.

Actuals 2014-2022

2014 = 0%
2015 = 0%
2016 = 0%
2017 = Less Than 1%

Forecast 2018– 2022

2018 = Less Than 1%
2019 = Less Than 1%
2020 = Less Than 1%
2021 = Less Than 1%
2022 = Less Than 1%

OEB Staff Interrogatory # 88

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 1.1 Page: 35

Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) CHANGES TO ASSET MANAGEMENT PROCESS

"Since Hydro One's last distribution application, it has implemented several improvements to its asset management process, such as restructuring the training process and content, improving data quality assurance and enhancing the enterprise engagement experience."

Interrogatory:

a) Please explain how each of the listed improvements explicitly relate to Hydro One's Asset Management process.

b) Please explain what is meant by 'enhancing the enterprise engagement experience' and provide concrete examples.

Response:

a) A core component of Hydro One's asset management process is planning to achieve the company's asset management objectives including assurance that appropriate processes are in place to manage assets over their life cycles. These processes include the identification of what actions are required to address risks and opportunities associated with managing assets, what will be done, and what resources are required. Additionally, having a workforce with appropriate training and experience and clearly identified information requirements, including quality, are critical to support Hydro One's asset management system and the achievement of the company's objectives. For Hydro One, many of these steps are embedded within the Investment Planning Process.

The listed improvements, including enhancing enterprise engagement and how they explicitly relate to Hydro One's Investment Planning Process are as follows:

- Restructured training – Annual process and tools training provides those that participate in the Investment Planning Process the necessary context and direction with which to effectively participate in the Planning Process.

- Data Quality Assurance – Data quality mitigates potential issues with the investment in advance of optimization, and results in a more efficient process and better investment plan as a result.

Enhancing Enterprise Engagement - The enterprise engagement enhancements relate to a stakeholder session held prior to the start of the investment planning process to set expectations for timelines and deliverables. This upfront collaboration engages employees across the organization, promoting participation in the Investment Planning Process.

b) Enhancing the enterprise engagement phase builds on the core portion of enterprise engagement, which includes collaboration with work execution teams to validate that the plan outcomes are achievable. As noted above, the enhancements relate to a stakeholder session held prior to the start of the investment planning process. A few examples of items discussed at this meeting are:

- Unit Price Catalogue – a timeline for unit price catalogue development and acceptance review was outlined.

- Timelines for Enterprise Engagement – the timelines for enterprise engagement were communicated.

The core enterprise engagement phase is described in DSP section 2.1.5.2.

OEB Staff Interrogatory # 89

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 1.1 Page: 35-36
Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) Changes To Asset Management Process

Ref: Exhibit B1/Tab1/ Schedule 1 – DSP Section 2. 1: Investment Planning Process Section 2.1.4.2 Risk Assessment, Pages 2382 – 2384

"Investment Planning Training

> *Investment planning training was restructured into major components of the overall process to assist planners and management in the development of investment plans.*
> *The first training segment outlines key influences on the investment planning process, such as regulatory requirements and details various aspects, requirements and deliverables during the process cycle. This segment is to help ensure planners and managers understand the expectations and conditions in which to develop plans.*
> *The second segment was developed to assist planners in developing appropriate risk assessments for candidate investments. Illustrative examples are used to help planners understand the alignment of investments to the overall corporate business objectives and foster consideration of alternative approaches to articulate investment risk.*
> *The third segment details the elements of the Asset Investment Planning ("AIP") tool to ensure planner awareness of optimization criteria that would affect investment candidates during the optimization process.*
> *In the interest of operating as one company, Hydro One structured training sessions for each of the key asset management business units involved in the planning process to create a focused environment and ensure consistency across the planning groups. Further review of the investment planning process resulted in an initiative for management training on optimization. This detailed overview provides management insight into the optimization process and its effect on their candidate investments within Hydro One's overall investment portfolio."*

Interrogatory:

a) What exactly is being optimized in the AIP?

   i. Please provide the parameters and targets used by Hydro One in the optimization process.

   ii. Please provide examples of projects and programs which have been optimized using the AIP process.

b) Does any of the above training involve learning how to prepare business cases to improve investment optimization? If yes, please provide concrete examples.

c) Hydro One has stated that risk is a product of consequences and probability and the risk assessment is developed by planners. How does the planner develop the risk assessment?

   i. Please explain how the planner differentiates the consequences of each cost driver from “minor” to “catastrophic”

   ii. Please explain how the planner calculates the probability of each consequence from “unlikely” to “very likely”.

   iii. Is this method consistently used for all capital investments?

Response:

a) The Asset Investment Planning tool optimizes the entire portfolio of candidate investments, with the prioritization criteria and financial constraints. Program investments may have multiple alternatives, with varying levels of expenditure and risk mitigation while project investments may have variable timing. The Asset Investment Planning tool identifies a combination of investment alternatives and alternative start dates which maximizes economic value (risk mitigation) within the specified financial parameters.

   i. Table 1 provides the financial parameters used in initial optimization.

Table 1: Financial Parameters

	2018	2019	2020	2021	2022
Distribution Capital	679	703	725	750	779
Distribution OM&A	568	575	583	591	597

Table 34 in section 2.1 of the DSP (Exhibit B1-1-1) provides the proportional weighting of each optimization factor (see Table 34 – Hydro One’s Prioritization Criteria and Weightings, page 2386 of 2930).

ii. Examples of investments optimized include:
- SR-09 Pole Replacement Program; and
- SR-06 Distribution Station Refurbishments.

b) The training does not explicitly include information on how to prepare business cases to improve investment optimization. However, the training includes an overview of the optimization process and investment characteristics that improve the optimization process, including:

i. Investment Flexibility – Identifying multiple program alternatives and flexible project start dates to increase the number of potential optimization solutions that can be considered and assessed; and

ii. Develop Program Investment Alternatives for assets with similar risk profiles – Grouping program investment alternatives with similar risk profiles of potential events.

c) Planners use asset, system and investment specific information, as noted in section 2.1.3 (Needs Assessment) of the DSP (Exhibit B1, Tab 1, Schedule 1), to inform their investment level risk assessment.

i. The consequence component of the risk assessments are assessed against a consequence taxonomy table which includes descriptions of potential negative outcomes for “minor 1” to “catastrophic” for each of the risk factor value measures. Factors such as typical customer impact of equipment failure typically inform the consequence assessment. The consequence taxonomy table for distribution is included as Appendix A.

ii. The probability component of risk assessments are assessed against a probability taxonomy table which includes descriptions for probabilities ranging from “unexpected” to “very likely”. Factors such as asset condition or likelihood of an event occurring typically inform the probability assessment. The probability taxonomy table for distribution is included as Appendix B.

iii. Consistent guidance is provided to all planners regarding the structure and approach to risk assessments through training, and management review is leveraged to drive consistency within business units. A cross-functional calibration session was introduced in 2016 to improve the consistency across business units, by providing transparency to risk assessments and identification of outlier investments.

Appendix A

	SAFETY*		CUSTOMER		ENVIRONMENT		EMPLOYEES	PRODUCTIVITY	RELIABILITY		SHAREHOLDER VALUE				
Event	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction inOSHA Recordable injuries.	Public Injuries (with Hydro One at fault)	Failure to meet Service Quality Indicies.	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Adverse Environmental Impact	Adverse emission (carbon footprint / greenhouse gas)	Change in employee engaement survey results.	Failure meet Unit Cost targets per plan	Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	Frequency of Distribution Outages Number of customers interrupted for > 1 minute	Cost Impact	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities (OEB/ IESO/NERC/NPCC/WSIB etc) including non- compliance.	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction
Minor1 **Noticeable disruption to results; manageable.**	Meets planned improvement in health and safety targets	No Change in number of injuries	Achieved or exceeded Overall Expected Performance	Stable satisfaction as per survey responses (as measured by scorecard).	No impact on Hydro One Inc.	Anticipated improvement relative to work program in carbon footprint / greenhouse gas are achieved.	On-plan improvement achieved in Employee Survey Results.	Unit costs reduction less than planned	< 20,000 Customer Interruption Hours	< 10000 Interruptions	0-$500K				No Consequence
Minor2 **Noticeable disruption to results; manageable.**									20,000 to 50,000 Customer Interruption Hours	10000 to 25000 Interruptions	$500K-$1M				
Minor3 **Noticeable disruption to results; manageable.**									50,000 to 500,000 Customer Interruption Hours	25000 to 100000 Interruptions	$1M-$2M				
Minor4 **Noticeable disruption to results; manageable.**									500,000 to 5 Million Customer Interruption Hours (equivalent to SAIDI of <0.8 to 3.8 hrs)	100000 to 200000 Interruptions	$2M-$3M				
Minor5 **Noticeable disruption to results; manageable.**	Safety targets met, but minor concerns regarding future performance.		Achieve only 95% (to 100%) of Overall Expected Performance	Less than planned improvement in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor impact on Hydro One Inc property only e.g. <3,000 L non-PCB material released or < 5% increase in non-recoverable spills/leaks above historical levels	Marginally less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Less-than-planned improvement achieved in Employee Survey Results.		5 Million to 7 Million Customer Interruption Hours (equivalent to SAIDI of 3.8 to 5.4 hrs)	200,000 to 500,000 Interruptions	$3M-$5M	Some concern with management decisions; Occasional requests from owner for details	Credible letter(s) to Senior Management	Balanced; some challenges.	Regulatory Warning, conditional closeout without sanctions.
Moderate **Material deterioration in results; a concern; may not be acceptable; management response would be considered.**	Less than planned improvement in health and safety performance	Small Increase in Number of Injuries	Achieve on 90% (to 94%) of Overall Expected Performance	Slight deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Minor local offsite impact (e.g. a single residential property or private water supply); or Significant spill/release with impact on Hydro One Inc property only. e.g. 3,000 - 5,000 L non-PCB material released or 5 - 25% increase in non-recoverable spills/leaks above historical levels	Somewhat less than anticipated improvement relative to work program in carbon footprint / greenhouse gas.	Much Less-than-planned improvement achieved in employee survey results.	Unit Costs not reduced	7 Million to 8 Million Customer Interuption Hours (equivalent to SAIDI of 5.4 to 6.7 hrs)	500,000 to 1.25 Million Interuptions	$5M-$25M	Confidence in question; Owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action	Increase in Reporting Detail and Frequency (for HOI only)	Regulatory Order and/or financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry.
Major **Significant deterioration in results; not acceptable; management response.**	No improvement in health and safety performance	Moderate Increase in Number of Injuries	Achieve only 80% (to 89%) of Overall Expected Performance	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).	Significant local offsite Impact (e.g.. a public thoroughfare) e.g. >5,000 - 10,000 L non-PCB material released or >25% - 50% increase in non-recoverable spills/leaks above historical levels	No real improvement relative to work program in carbon footprint / greenhouse gas initiatives.	No improvement achieved in employee survey results.	Unit Costs increase by < 5%	8 Million to 10 Million Customer Interruption Hours - note: current performance is 8.8 hrs and 5 year average is 8.4 hrs (equivalent to SAIDI of 6.7 to 8.3 hrs)	1.25 Million to 3.75 Million Interruptions	$25M-$100M	Material erosion in confidence; Shareholder Agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board	Significant local attention; Several opinion leaders/customers publicly critical	Some Concerns re: Competence; Difficult Demands	Conviction or regulatory finding of non-compliance with minor fine ("minor" meaning <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high/unprecedented amount for the industry).
Severe **Fundamental threat to operating results; immediate senior management attention.**	Employee/contractor critical injury due to failure of managed system. Significant deterioration in health and safety performance.	Significant Increase in Number of Injuries	Achieve only 67% (to 79%) of Overall Expected Performance.	Exponential increase (>30%) in: - call centre volumes (not storm related); - complaints received by field staff; - time and effort to resolve; Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).	Multiple local offsite impacts (e.g. multiple residential properties or private water supplies) e.g. >10,000 - 20,000 L non-PCB material released or >50% increase in non-recoverable spills/leaks above historical levels	Carbon footprint / greenhouse gas gets somewhat larger relative to work program and more visible to interested stakeholders.	Modest decline in employee survey results.	Unit Costs increase by 6% - 10%	10 Million to 15 Million Customer Interruption Hours (equivalent to SAIDI of 8.3 to 12.5 hrs)	3.75 Million to 7.5 Million Interruptions	$100-$300M	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced	Provincial media attention; most opinion leaders/customers publicly critical	Some loss of Credibility; Excessive Involvement;	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).
Worst Case **Results threaten survival of company in current form; potentially full time senior management response until resolved.**	Employee/contractor fatality or major permanent disability due to failure of managed system	Fatality or Major Permanent Disability	Achieve only 25% (to 66%) of Overall Expected Performance.	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments	Widespread offsite impacts (e.g. Regional or Municipal water supply) e.g. >20,000 L non-PCB material released	Carbon footprint / greenhouse gas gets substantially larger relative to work program and more visible to interested stakeholders.	Sharp deterioration in employee survey results.	Unit Costs increase by > 10%	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)	>7.5 Million Interruptions	>$300M	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate	National media attention; opinion leaders/customers nearly unanimous in public criticism	General loss of Credibility; Intrusive Involvement;	Conviction with Incarceration of Staff

Appendix B

Likelihood Scale	Expectation of Event Frequency in years	Probability in Planning Period (5 years)	Probability in 1 year
Very Likely	>1 in 2	> 95%	>50%
Likely	1 in 2 to 1 in 5	95% to 65%	20 - 50%
Medium	1 in 5 to 1 in 20	65% to 25%	5 – 20%
Unlikely	1 in 20 to 1 in 100	25% to 5%	1 – 5%
Remote	1 in 500 to 1 in 100	1% - 5%	1 in 500 to 1 in 100
Unexpected	<1 in 500	<1%	< 1 in 500

OEB Staff Interrogatory # 90

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 1.1 Page: 36

Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) Changes to Asset Management Process

> *"Data Quality Assurance*
> *The quality assurance process within the investment planning process was further developed to ensure the investment plan is successful in meeting customer expectations and corporate business objectives. Enhancements to the quality assurance process include weekly reporting to planners and management of investment data quality issues, a checklist for management review and a dedicated risk calibration session prior to optimization to promote risk assessment consistency across planning groups."*

Interrogatory:

a) Please provide examples of data quality issues that were identified after implementing the quality assurance process enhancements described above.

b) Please describe what was done to mitigate these data quality issues after they had been identified.

c) Was the mitigation confirmed to be effective in each case? Please provide details.

Response:

a) Examples include completion of risk and/or benefit assessments of investments, planning timeline governance and data input completion such as date criteria for investments with the ability to shift investments in time or the program accomplishment units entered. The manager checklist is a tool provided for manager review to assess the completeness and appropriateness of investment input including risk assessments and the investment planning assumptions.

b) Potential issues were identified to planners and managers for resolution on a weekly basis. As required, the investment planning team followed up with the planner or manager to confirm the team's understanding of the potential issues and the required action(s).

c) Throughout the investment planning process, data issues are resolved with the accountable planner / manager. The table below shows the identification and resolution of issues over time.

Week ending	**# of Short term Planning Investments**	**# of Investments with potential issues**	**# of issues**
June 10	362	246	374
June 17	360	246	385
June 24	360	190	266
July 1	354	117	139
July 8	381	147	176
July 15	374	143	166
July 22	397	160	189
July 29	439	124	146

OEB Staff Interrogatory # 91

Issue:

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

Reference:

B1-01-01 Section 1.4-A01 (5.2.3) Page: 1954

Performance Measurement and Outcome Measures, Section 1.4.3.2: Operational Effectiveness Investments

"Distribution Station Component Planned Replacements Program ISD SR 04
This investment replaces station equipment components that are at the end of their useful life and are not otherwise planned to be addressed by the station refurbishment program."

Interrogatory:

a) Please provide a table listing the expected "useful life" for all major equipment and asset classes.

b) Please show how Hydro One determined these "useful life" values (i.e., provide the quantitative basis for calculating the useful life values).

c) Please identify which asset classes are normally replaced solely based upon having reached end of "useful life"; which are replaced based upon asset condition assessments; and which are replaced based on a combination of these parameters.

Response:

a) "End of useful life" is used here to describe an asset that, as indicated via condition assessments, has reached its end of life and requires replacement. Hydro One does calculate "expected service life", which is the expected time an asset will survive in the system when it is installed. A table listing expected service lives is found in the 2016 Depreciation Rate Review in Exhibit C1, Tab 6, Schedule 1, Attachment 1.

b) End of “Useful life” is determined for each asset based on the condition assessment; it is not defined for entire classes of assets. Please see the 2016 Depreciation Rate Review noted in part (a) for a table of “expected service lives” by asset class.

c) By definition, there is no distinction between an asset that has reached the “end of useful life”, and one which is deemed to be at end of life based on condition assessments. Assets are replaced when they reach end of life.

OEB Staff Interrogatory # 92

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: 2361

(5.3.1) Investment Planning Process, Figure 9 - Hydro One's Investment Planning Process

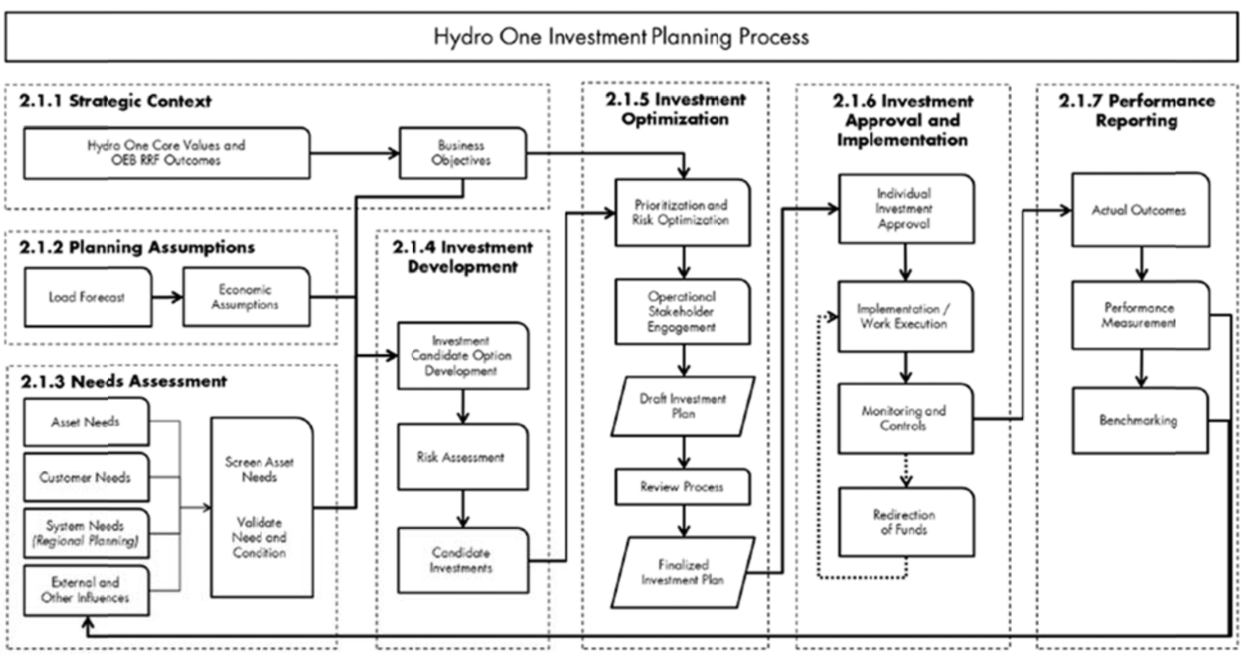


Figure 9 - Hydro One's Investment Planning Process

Interrogatory:

a) Does "Prioritization and risk optimization" in Hydro One's Investment Planning Process include economic optimization?

b) How is the Risk Assessment in Investment Development being done? Please provide details.

Witness: JESUS Bruno

Response:

a) The investment planning process determines the optimal economic value of risk mitigation for the portfolio of investments within the period specified.

b) The risk assessment process follows the process as outlined in section 2.1.4.2 of the DSP (Exhibit B1, Tab 1, Schedule 1), and the structured process that includes the following key steps: risk/hazard identification; risk analysis and controls assessment; and risk treatment. Please see part c) of Exhibit I-24-Staff-89. Additional information on the risk assessment approach is included in the investment planning risk assessment training materials provided in Exhibit I-24-SEC-40.

OEB Staff Interrogatory # 93

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: 2371
(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Figure 10 - Asset Need Development Process

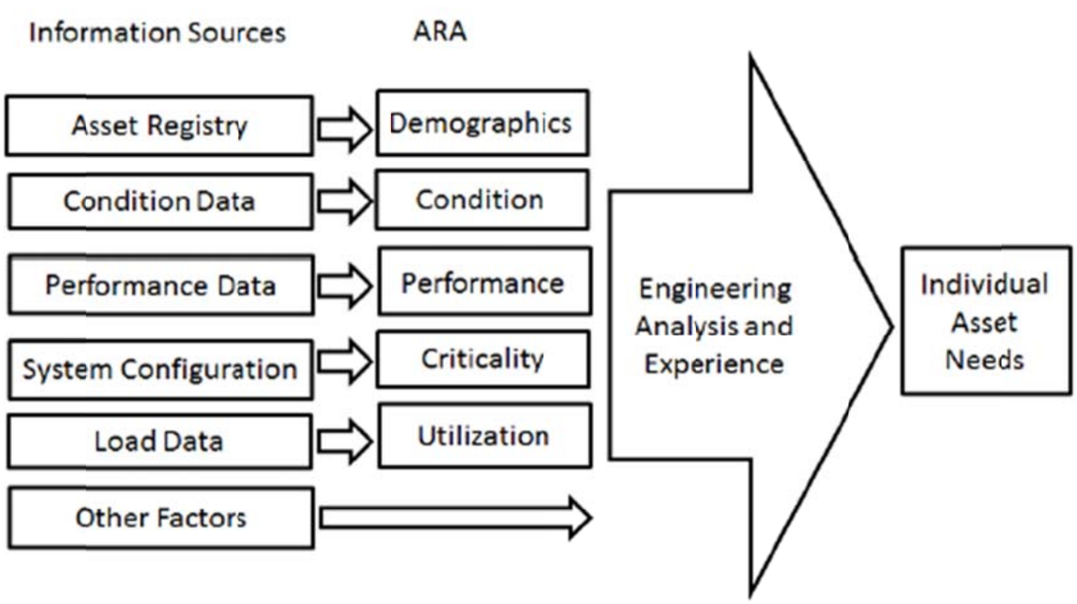


Figure 10 - Asset Need Development Process

Interrogatory:

Are there any quantified algorithms or calculations utilized to identify individual asset needs, or is this primarily a qualitative process that involves applying judgment and experience? Please explain in detail.

Response:

There are no algorithms or calculations which, on their own, are used to identify individual asset needs.

As part of the Asset Risk Assessment step of the asset need development process, there are quantified algorithms used to ascertain specific risks associated with various asset types. The results of these algorithms form part of the basis on which the engineering analysis and experience is applied to identify individual asset needs.

For example, the results of a dissolved gas analysis for a station transformer are fed into an algorithm to provide insight into the condition risk of the transformer. The condition risk is subsequently incorporated into a more comprehensive qualitative analysis in order to determine the needs of that particular transformer.

OEB Staff Interrogatory # 94

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: 2371
(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS

"Asset Demographic Risk

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

Interrogatory:

a) Please confirm that the term risk is used here as shorthand for probability of failure, rather than probability and consequence of failure.

b) Is the probability of asset failure due to age a more significant causal factor driving Hydro One outages than the probability of failure due to tree contacts and storms? Please explain using quantitative examples.

Response:

a) The term "risk" refers to the combination of the probability of failure and the consequence of such a failure.

   While the probability of failure typically increases as an asset ages, the consequence of failure is independent of asset age. Since risk depends on both probability and consequence, the asset demographic risk generally increases with increasing age.

b) Storms and tree contacts are generally only linked to asset failures of distribution lines assets. During these events, the tree contacts or storm forces themselves are the primary causes of asset failures. While increasing age can reasonably be linked to deteriorating condition, and deteriorating condition can result in a higher probability of failure during adverse events, age itself is not a causal factor that drives outages. Please see section 1.4 of the DSP (Exhibit B1, Tab1, Schedule 1), Table 14 – SAIFI by Outage Cause (page 1940 of 2930) which provides a breakdown of outages including Defective Equipment and Tree Contact.

As a percentage of total SAIFI:

	2012	2013	2014	2015	2016
Adverse Environment	0%	0%	0%	0%	0%
Defective Equipment	20%	23%	23%	25%	22%
Foreign Interference	4%	3%	5%	4%	5%
Human Element	1%	1%	2%	2%	1%
Loss of Supply	15%	9%	17%	14%	14%
Scheduled	17%	15%	18%	17%	17%
Tree Contacts	22%	29%	17%	22%	24%
Unknown/Other	22%	19%	17%	17%	17%

OEB Staff Interrogatory # 95

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: 2371-2372
(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS

"Asset Demographic Risk

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

Interrogatory:

a) Are any of Hydro One's asset replacement candidates selected based solely on demographic age? If so, please provide a list of these candidates.

b) Is demographic age a primary driver for replacement of any asset classes? If yes, please list those classes and the reasons for choosing demographic age as the primary driver, rather than asset condition.

c) Is there a database of different deterioration rates by makes and model for each asset? If so, please provide.

Response:

a) No, age is not the sole or primary driver for replacement for any asset classes.

b) See answer to part (a).

c) There is no database of deterioration rates by make and model.

OEB Staff Interrogatory # 96

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: 2372

(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS

"Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time. Asset condition is defined using different criteria depending on the asset. For example, the condition of a distribution station transformer is measured by visual inspection and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test and, if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently."

The Navigant study [Reference: DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 1: Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile] indicates that Hydro One primarily uses visual inspections and less frequently employs sounding and boring tests to assess wood pole condition.

Interrogatory:

Does Hydro One typically utilize more than one testing approach on a pole before designating it for replacement? Please explain why or why not.

Response:

Yes. Please refer to page 18 in Exhibit C1, Tab 1, Schedule 2 for a description of the pole testing methodology currently used by Hydro One. For any given pole, a combination of tests can be used to ascertain pole condition.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 97

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: 2372

(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS

"Asset Performance Risk

> *Asset performance risk reflects the historical performance of an asset. Performance is defined by any power interruptions that have been caused by failure of the asset. Hydro One tracks the failure of an asset and customer power interruption data using its distribution Outage Response Management System. This risk factor considers the frequency and duration of these interruptions, as well as whether the interruptions are occurring more or less frequently over time. Past performance can be a good indicator of expected future performance."*

Interrogatory:

Please identify the Hydro One asset classes for which replacements are driven primarily or substantially by asset performance risk. Please provide quantified details.

Response:

Individual assets classes are not replaced due to performance risk.

For distribution lines assets, performance is measured by feeder section, which comprises a number of line assets (i.e. poles, line transformers, conductor, switches, etc). A poorly performing feeder section can indicate the need for a line refurbishment under the SR-12 Distribution Lines Sustainment Initiatives or an investment under the SS-06 Worst Performing Feeders program. For details on these programs please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 98

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: 2373
(5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS

> ***"Asset Utilization Risk***
> *Asset utilization risk represents the increased rate of deterioration (or increased risk of failure) exhibited by an asset that is highly utilized. While not all assets exhibit this increased rate, the deterioration of some assets is highly dependent on the loading placed upon them or the number of operations they experience. For example, transformers that are heavily loaded beyond their nameplate rating deteriorate more quickly than those that are lightly loaded. Therefore, the asset utilization risk for transformers attempts to consider their relative deterioration based on available loading history."*

Interrogatory:

a) Please provide examples of specific assets that Hydro One has identified for replacement utilizing the asset utilization metric as the primary driver. Please show the algorithm applied to make the replacement decision.

b) Does the utilization calculation consider the season and ambient atmospheric conditions at the time of maximum loading? For example, are transformers evaluated to determine if their peak loading occurs during colder winter months?

Response:

a) The utilization metric generally refers to the loading of an asset as compared to its capacity. Hydro One replaces station transformers and station reclosers when these are found to be approaching or exceeding their loading limits or short circuit ratings, respectively.

b) Yes. Loading limits for transformers vary depending on the season. Please refer to interrogatory response Exhibit I-24-Staff-107 for further details on loading.

OEB Staff Interrogatory # 99

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: 2378
(5.3.1) Investment Planning Process, Section 2.1.4.1 Investment Candidate Option Development

> ***"System Renewal***
> *In general, identifying and selecting System Renewal investments consist of several steps. The first step is to consolidate the risk information identified in the Needs Assessment by major asset type. The next step is to identify options to mitigate risk for assets that are deemed to have a significant increased risk of failure. Hydro One then reviews the needs of assets in close proximity to determine if there are opportunities for an integrated stations or lines centric investment. Hydro One relies upon the factors used to evaluate risk including condition, criticality, performance and demographics as described in Section 2.1.3.1. The aggregate risk is then used to prioritize the assets within an asset type and centric investment types. Following this prioritization, alternative levels of accomplishment and their corresponding levels of risk to which Hydro One will be exposed, are defined. Finally, the preferred option to mitigate the asset risk is selected using the Investment Optimization process described in Section 2.1.5."*

Interrogatory:

a) Please provide examples of the data sets utilized in this step. Are individual assets identified for replacement or refurbishment utilizing this information, or is this analysis done on group basis?

b) Does Hydro One intend to use "significant risk of failure" to mean the same thing as "probability of failure" in this statement?

c) Do any of the listed factors other than condition have a significant bearing upon expected performance or likelihood of imminent failure of a given asset?

d) Please provide quantified examples of calculations carried out using these factors that have actually been used to identify individual assets for replacement.

e) Please demonstrate using any available analysis or calculations how the Hydro One process described above differs from a force ranked capital envelope approach, whereby a subset of a prioritized list of projects is created by selecting the highest priority projects until the expenditure envelope cap has been reached.

Response:

a) Please refer to Exhibit I-24-Staff-119 part (b) for examples of data sets used to determine to risk by major asset type.

No, individual assets are not identified for replacement solely on this step. This step identifies candidates for replacement which are then selected after engineering analysis and experience is applied.

b) “Significant risk of failure” does not mean “"probability of failure". As explained in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1.4.2, Hydro One defines the level of risk as a product of likelihood (i.e. probability) and severity (i.e. consequence).

c) Yes, as described in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1.3.1, the condition, performance, utilization, and demographic risk factors all have the potential to contribute to asset performance or likelihood of failure. Though condition is the most predominant factor.

d) Please see table below for an example calculation for distribution stations.

$$Composite = \sum (Risk\ Score) \times (Weighting)$$

Station Calculation	Condition	Demographics	Criticality	Composite Score
Risk Factor Weightings	*55%*	*25%*	*20%*	*100%*
Score for Blenheim DS	64	99	17	63

e) Hydro One’s process differs from the forced ranked capital approach, as several options with alternative levels of expenditure and associated accomplishment are developed by asset type. The corresponding levels of risk to which Hydro One will be exposed, are defined for each option. The preferred option and corresponding expenditure envelope to mitigate the asset risk is selected using the Investment Optimization process described in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1.5.

OEB Staff Interrogatory # 100

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: 2383
(5.3.1) Investment Planning Process, Section 2.1.4.2 Risk Assessment

> *"A risk assessment is undertaken for two scenarios: (a) a baseline risk evaluation, representing the risk of not proceeding with the investment; and (b) a residual risk evaluation, representing the remaining risk after the investment is put into service."*

Interrogatory:

Please provide a comprehensive listing of the results of the risk assessments described in (a) and (b) for all of the System Renewal projects included in the capital forecast in this filing for which this analysis was carried out.

Response:

The table below shows the baseline and residual risk evaluation for System Renewal investments over the 2018-22 period; these assessments are guided by the consequence and probability taxonomy tables included as Appendices A and B to Exhibit I-24-Staff -89.

In addition to the risk assessment, there are other operational considerations that may drive an investment. For example, as noted in ISD SR-013 (Life-Cycle Optimization and Operational Efficiency) in section 3.8 of the DSP, Exhibit B1, Tab 1, Schedule 1 (page 2644 of 2930), projects may provide:

- higher load meeting capability;
- better power quality;
- reduced line losses; and
- opportunities to achieve overall cost savings by bundling asset renewal work.

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
ISD-SR-01 - Distribution Stations Demand Capital Program											
DS Demand/Emergency Capital Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
DS Demand/Emergency Capital Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Medium / Minor3	Medium / Minor3	Medium / Minor3	Medium / Minor3	Medium / Minor3
DS Demand/Emergency Capital Program	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
DS Demand/Emergency Capital Program	Shareholder Value Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1
ISD-SR-02 - Mobile Unit Substation Program											
DS MUS Purchase Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Minor5	Very Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
DS MUS Purchase Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS MUS Purchase Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Likely / Minor4	Likely / Minor4	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3
DS MUS Purchase Program	Safety Risk	Very Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Minor5	Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
DS MUS Purchase Program	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate	Very Likely / Minor1	Very Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1
ISD-SR-03 - Station Spare Transformer Purchases Program											
DS Transformer Purchase Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Transformer Purchase Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Transformer Purchase Program	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4
ISD-SR-04 - Distribution Station Planned Component Replacement Program											
DS Component Replacement Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Component Replacement Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
DS Component Replacement Program	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3
ISD-SR-05 - Distribution Station Feeder Protection Upgrade											

		Baseline Risk Assessment						Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**		**2018**	**2019**	**2020**	**2021**	**2022**
DS Recloser Upgrade Program	Customer Risk	Likely / Minor5	Medium / Moderate	Medium / Major	Likely / Major	Likely / Major		Likely / Minor5	Likely / Minor5	Likely / Moderate	Likely / Moderate	Likely / Moderate
DS Recloser Upgrade Program	Reliability Risk	Medium / Minor3	Likely / Minor3	Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3		Medium / Minor3	Medium / Minor3	Medium / Minor3	Likely / Minor3	Likely / Minor3
DS Recloser Upgrade Program	Safety Risk	Medium / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unlikely / Severe	Unlikely / Severe	Medium / Minor5	Unlikely / Minor5	Unlikely / Minor1
DS Recloser Upgrade Program	Shareholder Value Risk	Medium / Minor5	Unlikely / Major	Medium / Major	Likely / Major	Likely / Major		Medium / Minor5	Medium / Minor5	Unlikely / Major	Medium / Major	Likely / Major
ISD-SR-06 - Distribution Station Refurbishment												
DS Station Refurbishment Program	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS Station Refurbishment Program	Environment Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate		Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5
DS Station Refurbishment Program	Reliability Risk	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor4	Very Likely / Minor4		Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor4
ISD-SR-07 - Distribution Lines Trouble Call and Storm Damage Response Program												
Dx Capital Trouble Call Damage Claims	Customer Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Customer Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Damage Claims	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Reliability Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Reliability Risk	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic	Likely / Catastrophic		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Reliability Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Damage Claims	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Safety Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Safety Risk	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Safety Risk	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

Witness: JESUS Bruno

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Dx Capital Trouble Call Damage Claims	Shareholder Value Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Call Poles & Equipment	Shareholder Value Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Post Trouble Call & Power Quality	Shareholder Value Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Storm Damage	Shareholder Value Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dx Capital Trouble Sub and UG Cable	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-08 - Distribution Lines PCB Equipment Replacement Program											
PCB Overhead Equipment Replacement	Shareholder Value Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-09 - Pole Replacement Program											
End of Life Replacement of Wood Poles	Customer Risk	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Major	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate
End of Life Replacement of Wood Poles	Reliability Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate
End of Life Replacement of Wood Poles	Safety Risk	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
End of Life Replacement of Wood Poles	Shareholder Value Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate
ISD-SR-10 - Distribution Lines Planned Component Replacement Program											
Component Replacement - Regulators/Recloser	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
Component Replacement - Sentinel Lights	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Conductor Replacement - Overhead	Customer Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate
Component Replacement - Nest Platforms	Environment Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4	Unexpected / Minor4
Component Replacement - Cross arms	Reliability Risk	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3	Very Likely / Minor3
Component Replacement - Nest Platforms	Reliability Risk	Medium / Minor4	Medium / Minor4	Medium / Minor4	Medium / Minor4	Medium / Minor4	Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2	Unlikely / Minor2
Component Replacement - Regulators/ Recloser	Reliability Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5
Component Replacement - Switches	Reliability Risk	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4	Very Likely / Minor4
Component Replacement - Transformers	Reliability Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
Conductor Replacement - Overhead	Reliability Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Component Replacement - Cross arms	Safety Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate
Component Replacement - Transformers	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5
Conductor Replacement - Overhead	Safety Risk	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Very Likely / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate
Component Replacement - Nest Platforms	Shareholder Value Risk	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Likely / Minor4	Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2	Unexpected / Minor2
ISD-SR-11 - Submarine Cable Replacement Program											
Conductor Replacement - Submarine	Safety Risk	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Likely / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe	Medium / Severe
Conductor Replacement - Submarine	Shareholder Value Risk	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Medium / Moderate	Remote / Moderate	Remote / Moderate	Remote / Moderate	Remote / Moderate	Remote / Moderate
ISD-SR-12 - Distribution Lines Sustainment Initiatives											
Large Sustainment Initiatives	Customer Risk	Unlikely / Moderate	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Small Sustainment Initiatives	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Large Sustainment Initiatives	Reliability Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Small Sustainment Initiatives	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Large Sustainment Initiatives	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Small Sustainment Initiatives	Safety Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1
Large Sustainment Initiatives	Shareholder Value Risk	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Likely / Moderate	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Small Sustainment Initiatives	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects											
Other Lifecycle Optimization Projects	Customer Risk	/	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phase	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Carleton Place DS Reconstruction	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phas	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Margach F3 voltage conversion	Customer Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
St Thomas DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Medium / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Dx Coniston Voltage Conversion	Customer Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Hanmer TS Feeder Development	Customer Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Burford DS Removal	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Customer Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Warkworth DS Removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Customer Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Customer Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Chesterville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Actons Corners Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Customer Risk	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Customer Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Employees Risk	/	Medium / Minor5	Medium / Minor5	Likely / Minor5	Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Employees Risk	Unlikely / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Unlikely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Environment Risk	/	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	Unlikely / Moderate	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
St Thomas DS Voltage Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Environment Risk	Unlikely / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Major	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Burford DS Removal	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment						Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**		**2018**	**2019**	**2020**	**2021**	**2022**
Warkworth DS Removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Environment Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Environment Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Environment Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Environment Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5		/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Environment Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5		/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Reliability Risk	/	Medium / Minor3	Medium / Minor3	Likely / Minor3	Likely / Minor3		/	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Clearwater Bay voltage conversion Phase	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Likely / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1
Carleton Place DS Reconstruction	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phas	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1		Likely / Minor1	Likely / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Margach F3 voltage conversion	Reliability Risk	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1		Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

Witness: JESUS Bruno

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
St Thomas DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Ridgetown Palmer DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Reliability Risk	Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Very Likely / Minor2	Likely / Minor2	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Dx Coniston Voltage Conversion	Reliability Risk	Medium / Minor2	Medium / Minor2	Medium / Minor2	Medium / Minor2	Medium / Minor2	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Hanmer TS Feeder Development	Reliability Risk	Medium / Minor2	Likely / Minor2	Likely / Minor2	Likely / Minor2	Likely / Minor2	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Burford DS Removal	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Princeton DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Barry's Bay Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Warkworth DS Removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Newport DS removal via voltage conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Front DS Voltage Convers	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Dundas Sydenham DS Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Turner DS Voltage Conversion	Reliability Risk	Medium / Minor1	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Ormond Voltage Conversion	Reliability Risk	Likely / Minor1	Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	Very Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Cleveland DS Voltage Con	Reliability Risk	Medium / Minor1	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Allanport DS Voltage Con	Reliability Risk	Likely / Minor5	Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	Very Likely / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Forest Jefferson and Mcnab DS Co	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lucan Market DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Wallaceburg DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1

Witness: JESUS Bruno

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Chesterville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Actons Corners Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	Medium / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Dresden DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Drumbo DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Anderdon DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Wardsville DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ridgetown DS Conversion	Reliability Risk	Medium / Minor1	Medium / Minor1	Likely / Minor1	Likely / Minor1	Likely / Minor1	/	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Brookside DS removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Lily Lake DS Removal	Reliability Risk	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	Likely / Minor3	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Safety Risk	/	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Other Lifecycle Optimization Projects	Shareholder Value Risk	/	Medium / Major	Medium / Major	Likely / Major	Likely / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Clearwater Bay voltage conversion Phase	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Carleton Place DS Reconstruction	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Manitou Lake DS & Line Work	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1	Unlikely / Minor1
Clearwater Bay voltage conversion Phas	Shareholder Value Risk	Medium / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Remote / Minor5	Remote / Minor5	Remote / Minor5
Margach F3 voltage conversion	Shareholder Value Risk	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor5	Likely / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Beaver Valley RS	Shareholder Value Risk	Unlikely / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unlikely / Major	Remote / Minor1	Remote / Minor1	Remote / Minor1	Remote / Minor1
Dx Coniston Voltage Conversion	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1

		Baseline Risk Assessment					Residual Risk Assessment				
Sub Description	**Risk Type**	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Hanmer TS Feeder Development	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Thorold Defoe DS Voltage Conversion	Shareholder Value Risk	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unlikely / Minor5	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1	Unexpected / Minor1
Alexandria Area Study	Shareholder Value Risk	Medium / Major	Medium / Major	Medium / Major	Medium / Major	Medium / Major	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Embrun Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Brockville Town Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Smiths Falls Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	Unexpected / Catastrophic	Unexpected / Catastrophic	Unexpected / Catastrophic
Chesterville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Ivy Lea Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Catastrophic	Unexpected / Catastrophic
Actons Corners Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Russell Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Maxville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Kemptville Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Prescott Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
Berwick - Finch Area Study	Shareholder Value Risk	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	Medium / Minor5	/	/	/	Unexpected / Minor1	Unexpected / Minor1
ISD-SR-14 - Advanced Meter Infrastructure Hardware Refresh											
AMI Hardware Refresh (EOL)	Shareholder Value Risk	/	/	/	Likely / Major	Likely / Major	/	/	/	Unlikely / Minor5	Unlikely / Minor5

Please note that typically risk mitigation is not realized until the year of in-service or the year following; as a result, any blank residual risk values reflect an investment not yet in-service, while blank baseline risk assessments indicate potential risks that have not yet presented themselves

OEB Staff Interrogatory # 101

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: 2384
(5.3.1) Investment Planning Process, Section 2.1.4.3 Candidate Investments

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.5.2 Operational Stakeholder Engagement, Page 2387

"Once the investment candidate options have been through a risk assessment, a structured, multi-level managerial review is conducted. The managerial review is focused on the need justification, the reasonableness of the risk assessment, and the appropriateness of the candidate investment options prior to its inclusion in the investment plan. A decision is made to accept the risk or mitigate the risk. Mitigation is designed to reduce the impact of the risk (consequence) or reduce the likelihood of occurrence (probability). For risks identified for mitigation, a list of recommended candidate investments with associated estimated cost and risk assessment are input into the investment optimization process and used to produce the optimized investment plan."

Interrogatory:

a) Please provide details to show how the described multi-level managerial review enables Hydro One to draw the very specific quantified relationships between level of capital investment and expected reliability results claimed in the public outreach materials filed in this application.

b) Please show how these anticipated reliability outcomes incorporate the impact of Hydro One's planned vegetation management investments.

c) Please show how the described process accounts for major weather events when predicting reliability outcomes.

d) Hydro One stated in the 2nd reference that after the investment optimization process, internal Hydro One stakeholders review the optimized plan and may make adjustments to reflect emerging execution risks and financial consideration.

i. Are these considerations not taken into account by the Asset Investment Planning tool? If not, why not?
ii. What justification or evidence is required for a stakeholder to make an adjustment to the optimized output? Are these adjustments documented? If so, please provide all such documentation.

Response:

a) The multi-level managerial review referred in the evidentiary excerpt did not enable Hydro One to quantify relationships between capital investment and expected reliability results associated with the public outreach materials, as the interrogatory suggests. The multi-level managerial review (referred to in the evidentiary excerpt) references the latter stages of the investment planning process. The public outreach materials were prepared much earlier in the overall timeline than this multi-level managerial review.

b) Please refer to Tables 52 and 53 (SAIDI Projection, SAIFI Projection) of section 2.4 of the DSP (Exhibit B1, Tab 1, Schedule 1) for the investment plan scenarios, pages 2500-2502 of 2930, and the impact of vegetation management.

c) As noted in Tables 52 and 53, major weather events are excluded from the analysis to predict reliability outcomes.

d)

i. Execution constraints, such as outage availability and resourcing are not optimized in Hydro One's Asset Investment Planning tool. These constraints are considered during the operational stakeholder engagement stage of the investment planning process.

ii. During the operational stakeholder engagement stage, feedback from stakeholders is provided to investment owners to assess and agree to any changes if an adjustment is required due to execution risks. The rationale and documentation of execution risk are discussed and agreed to between investment owners and the stakeholder and reflected in the resulting change to the investment.

OEB Staff Interrogatory # 102

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:

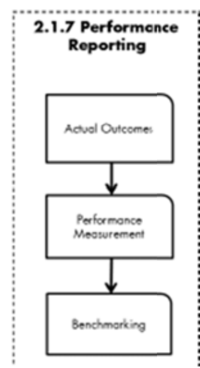
B1-01-01 Section 2.1 Page: 2391
(5.3.1) Investment Planning Process, Section (5.3.1 B) Performance Reporting, and Section 2.1.7.1 Actual Outcomes

"2.1.7 (5.3.1 B) PERFORMANCE REPORTING

The performance is monitored through tracking actual outcomes, measuring performance and benchmarking. The results of performance monitoring are utilized to facilitate continuous improvement of the plan in future years.

2.1.7.1 ACTUAL OUTCOMES

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 year."



Interrogatory:

a) Does this process include evaluating and confirming that the planned projects have been delivered, and not just that the overall planned capital envelope was spent? Please explain in detail.

b) Does Hydro One document lessons learned on each project? What is the formal close-out procedure for projects to ensure continuous improvement?

Response:

a) Yes, planned project delivery is tracked throughout the year, as explained in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.6.3 Monitoring & Control.

b) Hydro One documents the lessons learned as part of the close out process for all distribution station projects that have a cost exceeding $5 million. These distribution station projects are generally more complex than a lines project. For distribution lines projects, Hydro One tracks project progress against the planned cost, schedule and scope of the project and lessons learned are compiled for all projects that have a material variance of scope, schedule, or cost. These lessons learned result in assigned action to ensure that future projects incorporate the required change.

OEB Staff Interrogatory # 103

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 2.2 Page: 2400
(5.3.2) Overview of Assets Managed, Section 2.2.2.1 DISTRIBUTION STATIONS

> *"System asset utilization is assessed by Hydro One through planned area studies and system impact assessments. These studies are typically done on a cyclical basis (or on a demand basis if an urgent need arises). When any system assets are identified to approach or exceed Hydro One's established planning limits, corrective scopes of work are issued to address the concern. The source of utilization information for station loading is an annual data collection program through the use of electronic record in ammeters. Meters are installed on each phase of the station feeders and left for a week to record data. This data is then collected and loaded into a system simulation tool called CYME where the system 1 is then studied in detail. Advancements with Grid Modernization will eventually eliminate this method of data collection and allow asset loading to be sourced from the Distribution Management System ("DMS") using SCADA and DMS state estimation. Modernizing the grid will be key to delivering reliable and cost-effective services to our customers going forward. Remote monitoring and control of power system equipment will be undertaken largely in conjunction with asset renewals. Distribution station refurbishment projects (ISD SR-06) will provide such functionality that delivers better determination of fault location and restoration timelines. Further deployment of equipment monitored through the DMS will be implemented through the equipment replaced through the Worst Performing Feeders (ISD SS-06), Distribution Station Reclosers Upgrade (ISD SR-05) and Distribution Lines Planned Component Replacement (ISD SR-10). All of the remotely monitored and controlled devices will be enabled by communication infrastructure implemented in the Advanced Distribution System Project (IS SS-07). As well, another component of this project is the Advanced Metering Infrastructure Analytics ("AMIA") that will leverage the smart metering data to provide transformer, feeder and distribution station information on an asset-by-asset basis and will also allow aggregation at a station level according to the network connectivity model."*

Interrogatory:

a) How are the weeks for metering selected?

b) Given the seasonal variability of Hydro One loads, is the loading data collected in any given week considered to be fully representative of feeder loading over the entire year? Please explain in detail how the methodology compensates or adjusts for seasonal biases.

c) What is the projected date that station meters will no longer be required and can be replaced by DMS?

d) Hydro One has stated multiple investment components of DMS including station refurbishments, recloser upgrades, line component replacements. Please provide an analysis on the cost-benefit of DMS and an overall long-term implementation strategy including multiple penetration levels, if available.

Response:

a) Meters are installed to best capture peak station loading. Since the anticipated date of the peak loading of the upstream supply Transmission Station is known, meters are installed at a given station near to this date and the measured readings are prorated to coincide with the actual measured peak of the supply station.

b) No, the loading data collected is not considered representative of the feeder loading over the entire year. Planning criteria is generally based on peak loading, and the loading in the selected week is representative of the peak loading. Where consideration for seasonal variances is necessary, these are taken into account on a case by case basis.

c) The majority of electronic recording ammeters are not expected to be required after 2019 as they will be replaced with state estimation from the DMS or line sensors.

d) The Distribution Management System Enhancement project has been combined with the Selective Load Shedding project, Online Operating Diagrams project and Mobile System project into a single initiative within Advanced Distribution System Project (ISD SS-07). The cost-benefit analysis for the Distribution Management System project is break-even but provides the foundation for most of Hydro One grid modernization initiatives. The benefits are being derived mainly from:

- Improvement in efficiency of performing system studies,
- Reduction in the effort required to maintain the distribution network model, and
- Reduction in sustainment of computer infrastructure by virtualizing machines and requiring less servers as part of the DMS upgrade.

Please see interrogatory response to Exhibit I-23-Staff-87 part (b) for the overall long term strategy.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 104

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: 2412
(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1 STATION TRANSFORMERS AND REGULATORS

"Preventative Inspection and Maintenance Program

- *Thermovision Inspection – Annually, each station receives a thermography inspection of all power equipment, at which time the transformer is inspected to identify hot spots in any components."*

Interrogatory:

How is the timing for thermal inspections chosen? Is equipment heating correlated with daily and seasonal loading patterns?

Response:

As stated in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3; each station receives a thermography inspection of all power equipment annually. Hydro One Distribution schedules these station thermography inspections throughout the year. Ideally, Hydro One tries to perform these thermography inspections during higher loading periods such as in summer or winter months. However, performing these inspections in the winter is often difficult due to the amount of snow which could be in and around the station.

Yes, electrical equipment operating temperature will vary with loading patterns; the equipment operating temperature will rise as load increases and will drop as load decreases.

OEB Staff Interrogatory # 105

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: 2418
(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1 Station Transformers and Regulators, Figure 18 – Failures of Station Transformers

"Performance

The total number of failures varies from year to year. However, the number of major transformer failures (Class 1) and number of potential major failures avoided by proactively removing transformers from service (Class 2) are shown in Figure 18. Total failures have gone down on the system since 2013."

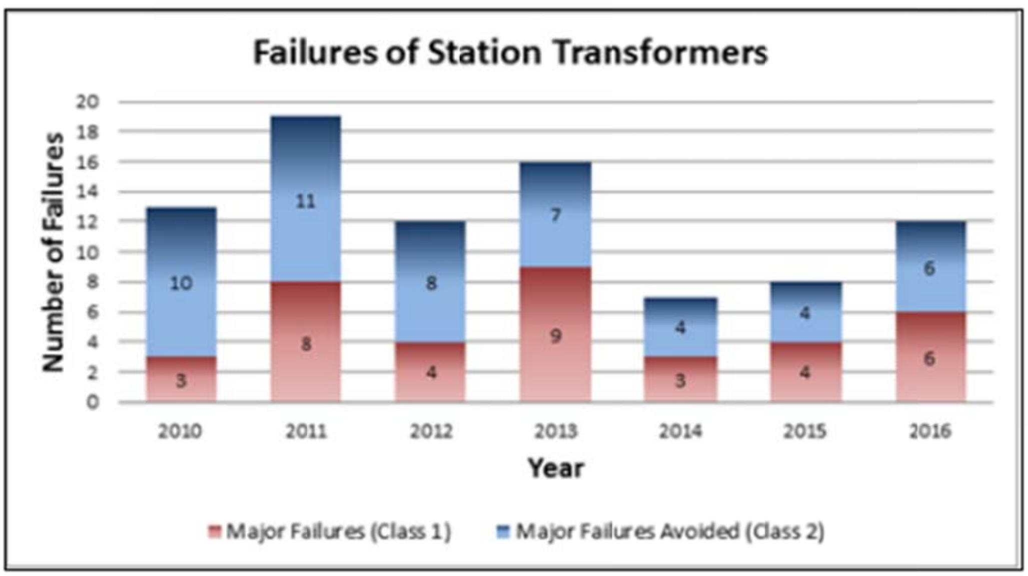


Figure 18 - Failures of Station Transformers

Interrogatory:

a) Does any transformer replaced prior to failure count as a major failure avoided (class 2), or are the class 2 failures categorized only when the transformer has been identified as being in imminent failure mode?

   i. If the latter, explain how this is done. Please provide quantitative observations used to classify that failure was imminent and evidence that these observations have historically led to failure.
   ii. If the former, shouldn't these be categorized as preventive replacements rather than transformer failures? Please explain in detail.

b) Please provide the number of outage hours experienced for each Major Failure for each year.

c) Please provide if the station had Mobile Unit Substation facilities for each Major Failure for each year.

d) What is the average time required to move a transformer from the spare transformer stock and install it in a distribution station under emergency situations? What is the average cost of this installation compared to a scheduled installation?

Response:

a) When transformers are identified as being subject to imminent failure, they are identified as a class 2 failure.

   The most common way to identify a transformer that is subject to imminent failure is through annual oil sampling. Following an unsatisfactory oil sample result, additional follow-up samples may be initiated for diagnosing suspected faults and verification of the previous oil sample result. Transformers condition can also be identified by warning level thresholds for dissolved gas analysis ("DGA") test results and oil condition in the transformer main tank and under-load tap-changer ("ULTC"). These warning level thresholds are primarily based on the IEEE C57.104-1991 standard.

   In general, transformers with sample results which have exceeded lower warning level threshold but have been evaluated to be stable over years of annual oil sampling will not be forced out of service, and failure is not identified as imminent. These transformers are considered for a planned repair or replacement.

Transformers which are identified as subject to imminent failure are those which have either exceeded the highest warning level thresholds for DGA or oil quality, or have subsequent sample results which show rapidly increasing gas levels. Transformers with under-load tap changers which have failed are also be classified as a class 2 failure.

b) The number of outage hours experienced for each major failure is identified in the following table:

Year	Station - Transformer	Outage Hours	Outage Restoration Method (MUS Facilities vs. Load Transfer vs. Onsite Spare)
2010	Dryden Rural DS - T1	0.00	Load picked up by onsite transformer (T2); no impact to customer.
2010	Earlton DS - T1	3.80	MUS facilities were used
2010	Vienna DS - T1	7.28	MUS facilities were used
2011	Callander DS - T1	0.00	MUS facilities were used. Single phase transformer failed without warning. Unable to locate outage hours.
2011	Earlton DS - T1	4.35	MUS facilities were used
2011	Holland Center RS - R1	0.00	Regulator failed causing customer voltage issues, but no interruption.
2011	Holland DS - T1	4.40	MUS facilities were used
2011	Lily Lake DS - T1	1.95	Load initially transferred to adjacent station to restore customers. MUS facilities later utilized.
2011	Roseville DS	0.76	Load initially transferred to adjacent station to restore customers. MUS facilities later utilized.
2011	Poonamalie DS - T1	0.00	MUS facilities were used. DGA test results indicated failure, but transformer was still supplying load. No interruption.
2011	Thorold South DS - T1	2.10	Load transferred to neighbor station in town.
2012	Golden Lake DS - T1	0.00	MUS facilities were used. Transformer ULTC failed causing customer voltage issues, but no interruption.
2012	Long Lac East DS - T1	0.00	Load transferred to neighbor station in town. Single phase transformer failed. Load transferred to neighbour station. Unable to locate outage hours.
2012	Red Rock DS - T1	3.16	Load transferred to onsite single-phase spare. MUS facilities not used.
2012	South Gower DS - T1	0.00	MUS facilities were used. Transformer ULTC failed causing customer voltage issues, but no interruption.
2013	Bowmanton DS – T1	4.15	MUS facilities were used
2013	Horsey Bay DS – T1	5.86	MUS facilities were used

2013	Madawaska DS – T1	0.00	MUS facilities were used. Transformer failed during installation. MUS was paralleled with transformer resulting in no interruption to customers.
2013	Maitland DS – T1	6.36	MUS facilities were used
2013	Margach DS – T2	0.00	Load picked up by onsite transformer (T1); no impact to customer.
2013	Midhurst DS – T1	14.41	MUS facilities were used
2013	Milford DS – T1	14.75	MUS facilities were used
2013	North Augusta DS – T1	14.64	MUS facilities were used
2013	St. Onge DS – T1	8.33	MUS facilities were used
2014	Lythmore DS – T1	9.97	MUS facilities were used
2014[1]	Post Creek DS – T1	8.91	MUS facilities were used
2014	Shannonville DS – T1	2.70	Load initially transferred to adjacent station to restore customers. MUS facilities later utilized.
2014	Snelgrove DS – T2	5.00	MUS facilities were used
2015	Crilly DS – T1 (red phase)	20.37	Load transferred to onsite single-phase spare.
2015	Perrault Falls DS – T1	8.79	Load transferred to onsite spare.
2015	Thorold Defoe DS – T1	2.20	Load transferred to alternate supply.
2016	Carleton Place Edmund DS-T1	3.26	Load transfer to neighbor station in urban town.
2016	Corbeil DS - T1	0.13	Load transferred to onsite single-phase spare.
2016	Kingston Woodbine DS - T1	3.56	MUS facilities were used
2016	Pinelands DS - T1	32.41	MUS facilities were used
2016	Russell DS - R1	3.87	MUS facilities were used
2016	Wesley DS - T1	2.10	Load initially transferred to adjacent station to restore customers. MUS facilities later utilized.

c) The table provided in question b) identifies which stations utilized MUS facilities for each major failure.

d) Hydro One utilizes a combination of mobile unit substations, load transfer to adjacent stations and/or an on-site transformer to backup stations in the event of a failure. Based on the failure data listed above, the average failure resulted in approximately 5.4 hours of interruption time to customers before restoration.

Once the customer load has been restored, then Hydro One undertakes the replacement of the failed transformer with a spare transformer. The time to dispatch a spare transformer from inventory and install it in a distribution station following a transformer failure varies greatly.

[1] *In Figure 18, the Post Creek DS T1 transformer failure was incorrectly captured as a 2015 major failure. Upon further review, this major failure occurred in 2014.*

This variance is largely due to differing levels of engineering required to accommodate the new transformer.

The average costs of these installations were $224,000. This cost includes engineering design, project management, short lead time materials and labour work. This does not include the cost of the spare transformer.

In recent years, all planned transformer replacements have been performed under station refurbishment projects, for which other station components in need of replacement such as reclosers, grounding, fence, structures, etc. were bundled with the transformer replacement. As a result, there is not a comparable cost available.

OEB Staff Interrogatory # 106

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: 2419
(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1 Station Transformers and Regulators, Figure 19 – Number of Transformer Replacements

"Performance
The reason for the decrease in failures in years 1 2014 and 2015 is the result of an increase in planned replacements of transformers in poor condition. Figure 19 shows a graph of the number of planned and unplanned station transformer replacements from 2010 to 2016. It can be observed that there has been a steady increase in total transformer replacements from 2011 to 2015. Similarly over this period, there has been an overall decrease in transformer failures."

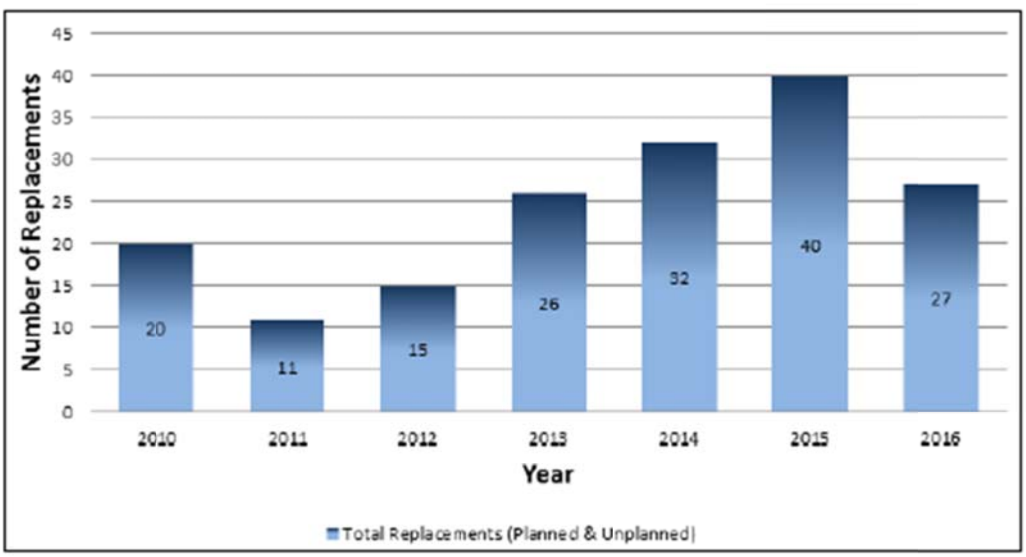


Figure 19 - Number of Transformer Replacements

Interrogatory:

Please describe the reason for the decrease in number of replacements during 2016.

Response:

The decrease in the number of transformer replacements in 2016 was due to a reprioritization of capital. The reprioritization occurred as a result of the actual cost per station refurbishment being higher than anticipated in the previous application (EB-2013-0416); as discussed in interrogatory response Exhibit I-26-Staff-159.

OEB Staff Interrogatory # 107

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: 2419

(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1 Station Transformers and Regulators, Figure 20 – Station Loading as a Percentage of Total Fleet

"Utilization

Station transformers that are overloaded, or are more heavily loaded, experience higher winding temperatures which shorten the life of the paper insulation within the transformer. These transformers are given a higher priority for replacement compared to those that are lightly loaded."

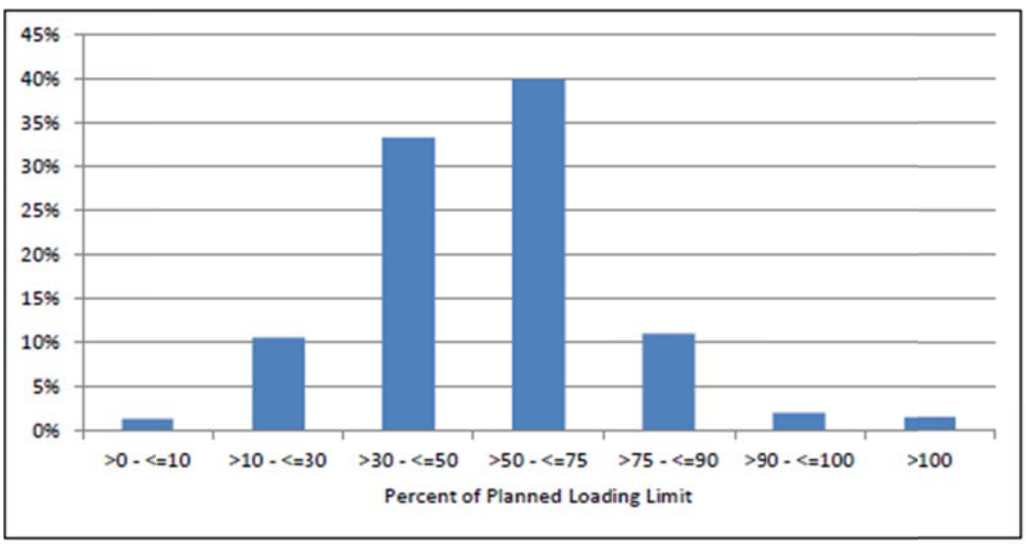


Figure 20 - Station Loading as a Percentage of Total Fleet

Interrogatory:

a) Does Figure 20 show peak loading, average loading or some other parameter?

b) Are loading levels prorated or otherwise adjusted to account for the mitigating effect of cooler ambient temperatures (and reduced summer loading patterns) in northern parts of Hydro One's service area?

c) Does Hydro One distinguish between winter peaking and summer peaking transformer loads?

Response:

a) The Station Loading in Figure 20 from Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3 is based on peak loading.

b) Loading levels are not prorated based on the location of a station in Hydro One’s service territory. However, planned loading limits for station transformers include a temperature component to account for the effects of ambient temperature.

c) Yes. Different planned loading limits are applied whether the station is summer peaking or winter peaking.

OEB Staff Interrogatory # 108

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: 2420

(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1: Station Transformers and Regulators

"Criticality

Transformer replacements are prioritized based on impact on downstream customers and magnitude of downstream load supplied. Higher priority is given to transformers that would impact a higher number of customers and a higher magnitude of load in the event of a failure."

Interrogatory:

Please provide a prioritized list of planned transformer replacements with associated justifications for replacement (i.e., please include number of customers impacted and magnitude of load that would be lost in the event of a failure).

Response:

Planned transformer replacements fall under the following three programs: SR-06 Distribution Station Refurbishments, SR-13 Life Cycle Optimization & Operational Efficiency, and SS-02 System Upgrades Driven by Load Growth depending on the main driver of the replacement. The transformers planned for replacement under these three investments are shown in the table below. The number of customers served is shown and the size of the transformer provides an indication of the magnitude of load that would be lost in the event of a failure.

Year	**ISD** *(ID)*	**Station Name**	**Existing Capacity (MVA)**	**Customer Count**	**Justification for Replacement**
2018	SR-06	Blenheim DS	3.6	995	Transformer in poor condition
2018	SR-06	Wainfleet DS	3	938	Transformer in poor condition
2018	SR-06	Duff DS	5	956	Elevated composite risk score
2018	SR-06	Gorrie DS	5	1143	Elevated composite risk score

Year	ISD *(ID)*	Station Name	Existing Capacity (MVA)	Customer Count	Justification for Replacement
2018	SR-06	Haliburton DS	6	1840	Environmentally sensitive area
2018	SR-06	Joyceville DS	6	1362	Transformer failed noise assessment
2018	SR-06	Meaford Vincent DS	5	796	Transformer in poor condition
2018	SR-06	Sowerby DS	2.2	912	No MUS facilities and weak transfer capabilities to nearby station.
2019	SR-13 *(LC-5)*	Carleton Place Bridge DS	4.5	917	Lifecycle Optimization, paired with replacement of poor condition transformer
2019	SR-13 *(LC-5)*	Carleton Place Edmund DS	5	628	Lifecycle Optimization, paired with replacement of poor condition transformer
2019	SS-02 *(LG-13)*	Goodfish DS	5	1211	Load growth
2019	SS-02 *(LG-21)*	Kirkland Lake Woods DS	5	1520	Load growth
2019	SR-13 *(LC-11)*	Lucan Market DS 4kV	3.6	776	Lifecycle Optimization, paired with replacement of poor condition transformer
2019	SR-13 *(LC-11)*	Lucan Market DS 8kV	3.6	912	Transformer in poor condition
2019	SR-06	Birch Island DS	6	1227	MUS pole in poor location, phasing reversed on HV ingress and short circuit levels nearing recloser rating
2019	SR-06	Brigden DS	3.6	848	Transformer in poor condition
2019	SR-06	Chatham Raleigh DS	3.6	1099	Transformer in poor condition
2019	SR-06	Dack DS	3	812	Transformer in poor condition
2019	SR-06	Ostrander DS	5	1111	Transformer in poor condition
2019	SR-06	Owen Sound DS #2	2	409	Transformer in poor condition
2019	SR-06	Shedden DS	3.6	1241	Transformer in poor condition
2019	SR-06	Stratford DS	3	698	Transformer in poor condition
2019	SR-06	Stratford East Hope DS	3	392	Transformer in poor condition
2019	SR-06	Ufford DS	3	946	Transformer in poor condition
2019	SR-06	Whitedog DS	2	239	Transformer in poor condition
2019	SR-06	Grand Valley DS #2	3	102	No MUS facilities and weak transfer capabilities to nearby station.
2019	SR-06	Hawley DS	4	1228	Elevated composite risk score
2019	SR-06	Troy DS	5	1041	Elevated composite risk score
2019	SR-06	Waupoos DS	5	2065	Transformer in poor condition
2020	SR-13 *(LC-20)*	Devlin DS	2	526	Transformer in poor condition

Year	ISD *(ID)*	Station Name	Existing Capacity (MVA)	Customer Count	Justification for Replacement
2020	SS-02 *(LG-17)*	Shelburne DS 8kV	3	1348	Load growth, paired with replacement of poor condition transformer
2020	SR-13 *(LC-18)*	Thorold Turner	3.6	543	Transformer in poor condition
2020	SR-06	Aspdin DS	6	2386	Elevated composite risk score
2020	SR-06	Carleton Place Edmund DS	5	628	Transformer in poor condition
2020	SR-06	Colpoys Bay DS	6	3420	Transformer in poor condition
2020	SR-06	Cobalt DS	3	1195	Transformer in poor condition
2020	SR-06	Kenora DS	3.6	1705	Transformer in poor condition
2020	SR-06	Oil Springs DS	4.7	326	Transformer in poor condition
2020	SR-06	Woodland Beach DS	5	1757	Transformer in poor condition
2020	SR-06	Island Grove DS	5	1398	Transformer in poor condition
2020	SR-06	Millington DS	5	1036	Elevated composite risk score
2020	SR-06	Nottawaga DS	5	1726	Elevated composite risk score
2020	SR-06	Reid Corners DS	3	1465	Elevated composite risk score
2020	SR-06	Tara DS #2	3	916	Elevated composite risk score
2020	SR-06	Washago DS	5	1823	Transformer in poor condition
2020	SR-06	Williamstown RS	25	N/A	Elevated composite risk score
2020	SR-06	Wroxeter DS	3	775	Elevated composite risk score
2021	SR-13 *(LC-26)*	Alex Industrial DS	5	254	Transformer in poor condition
2021	SS-02 *(LG-31)*	Dundalk DS	5	896	Load growth
2021	SR-13 *(LC-28)*	Elliot Lake Mississauga DS	6	1987	Transformer in poor condition
2021	SR-13 *(LC-22)*	Kemptville West DS	5	765	Load growth
2021	SR-06	Aberdeen DS	5	1550	Elevated composite risk score
2021	SR-06	Bothwell Corners DS	5	1346	Elevated composite risk score
2021	SR-06	Cedar Mills DS	20	3529	Transformer in poor condition
2021	SR-06	Constance DS	30	3204	Transformer in poor condition
2021	SR-06	Crown Hill DS	5	1087	Elevated composite risk score
2021	SR-06	Dwight DS	6	1963	Elevated composite risk score
2021	SR-06	Emsdale DS	6	3023	Elevated composite risk score
2021	SR-06	Ferndale DS	6	3473	Elevated composite risk score
2021	SR-06	Harriston DS #2	5	837	Elevated composite risk score
2021	SR-06	Keswick DS	10	2658	Elevated composite risk score
2021	SR-06	Lake Vernon DS	6	1532	Transformer in poor condition

Year	**ISD** *(ID)*	**Station Name**	**Existing Capacity (MVA)**	**Customer Count**	**Justification for Replacement**
2021	SR-06	Elmvale DS	3	1129	Transformer in poor condition
2021	SR-06	Emo DS	3	799	Transformer in poor condition
2021	SR-06	Milverton DS #2	5	826	Elevated composite risk score
2021	SR-06	Oxmead DS	7.5	2048	Elevated composite risk score
2021	SR-06	Willow Beach DS	5	1743	Transformer in poor condition
2021	SR-06	Wolsey Lake DS	6	816	Transformer in poor condition
2022	SR-13 *(LC-37)*	Sleeman DS	6	392	No MUS facilities and weak transfer capabilities to nearby station. Reduced asset footprint, regulator in poor condition
2022	SR-06	Belleville DS #2	5	1757	Transformer in poor condition
2022	SR-06	Blackstock DS	5	774	Transformer in poor condition
2022	SR-06	Brunelle DS	5	1092	Transformer in poor condition
2022	SR-06	Chemung DS	5	939	Transformer in poor condition
2022	SR-06	Coboconk DS	10	3248	Elevated composite risk score
2022	SR-06	Horning Mills DS	5	1126	Transformer in poor condition
2022	SR-06	Listowel Davidson DS	5	695	Elevated composite risk score
2022	SR-06	Madoc DS #2	6	1474	Elevated composite risk score
2022	SR-06	Pinestone DS	10	2527	Elevated composite risk score
2022	SR-06	Pleasant Point DS	6	1273	Elevated composite risk score
2022	SR-06	Precious Corners DS	5	1084	Elevated composite risk score
2022	SR-06	Schreiber Winnipeg DS	6	1018	No MUS facilities and weak transfer capabilities to nearby station. Regulator in poor condition
2022	SR-06	Shelburne Andrew DS	5	568	Transformer in poor condition
2022	SR-06	East Luther DS	6	1268	Transformer in poor condition
2022	SR-06	Tory Hill DS	6	2799	Elevated composite risk score
2022	SR-06	West Lorne DS	5	1328	Elevated composite risk score
2022	SR-06	Rutherglen DS	2.3	1019	Transformer in poor condition
2022	SR-06	Woodville DS	5	1171	Elevated composite risk score

OEB Staff Interrogatory # 109

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: 2432-2433
(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.4.1 MOBILE UNIT SUBSTATIONS, Table 42 – MUS Defects

"Condition

The condition of the trailer is inspected as required by the Ministry of Transportation and the electrical equipment is inspected in detail on an annual basis. Inspection and maintenance of the MUS electrical equipment (such as, the transformer, reclosers and switches) are identical to that of a distribution station but more frequent as these assets are relied upon during emergency situations. Any significant defects are logged and immediate plans are made to correct them."

Table 42 – MUS Defects

Year	Transformer Defects	Trailer Defects	Switchgear Defects	Cable Defects	Total MUS Defects
2012	8	5	11	5	**29**
2013	7	3	12	7	**29**
2014	18	9	16	10	**53**
2015	17	5	13	8	**43**
2016	14	9	12	16	**51**

Interrogatory:

a) Are the MUS transformers typically loaded only a small percentage of the time each year? If yes, does this reduce the aging of paper insulation and oil deterioration?

b) What are the primary drivers of the shorter TUL for MUS transformers in comparison with the TUL of fixed station transformers?

Response:

a) No, the MUS fleet is heavily utilized throughout the year.

b) MUS transformers have a shorter expected service life (or typical useful life ("TUL")) in comparison to fixed station transformers for several reasons.

As MUSs are deployed from station to station for various maintenance and capital activities, the MUSs are switched in and out of service multiple times throughout the year. Each time the MUS is placed in-service, the MUS transformer will experience in-rush currents which can reduce the useful life of the transformer. Station transformers in comparison which remain in-service for many years are only removed from service if they are undergoing maintenance or capital activities.

Hydro One distribution station transformers typically have some degree of overload capability. However, Hydro One MUS transformers are more compact in design, for ease of transportation, and require fans and pumps to be running at all times when supplying load. Therefore, these MUS transformers cannot be overloaded to the same degree as station transformers.

Thirdly, MUS transformers spend many hours per year travelling on the road. This places stress on the MUS transformer core and windings and can further reduce the useful life of the MUS transformer.

OEB Staff Interrogatory # 110

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: 2444
(5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.2.1 POLES

"Performance
Another driver of wood pole replacement work is the impact pole failures have on reliability. When poles fail, they are highly impactful and typically require an emergency pole replacement to restore service. These unplanned repairs are more difficult, take longer and are more costly than a planned pole replacement. The average duration of an unplanned outage involving a pole replacement is about nine hours. The average duration of a planned outage involving a pole replacement is about 2 hours. The improvement in outage duration for planned replacements, combined with the benefits of scheduling and notifying customers of work before it is done, drives Hydro One to replace end-of-life poles on a planned basis."

Interrogatory:

a) Are unplanned pole replacements often driven by factors other than pole condition, e.g.: extreme ice, wind and snow loading conditions, tree falls, vehicle contacts?

b) Does Hydro One correlate the demographics of failed poles against the initiating causes? If yes, please provide data demonstrating the correlation.

c) What percentage of pole failures involve poles failing without external drivers, e.g.: the pole falls over spontaneously without being pushed by high winds, heavy snow, ice or vehicle contact?

Response:

a) Unplanned pole replacements are driven by external forces placed on the pole (e.g. extreme ice/wind/snow loading, tree falls, and vehicle contacts); however, poles in poor condition have a reduced probability of resisting design loads applied to them, and thus have a higher probability of failure under such external forces.

b) No, Hydro One monitors the condition of poles, and replaces when the condition is poor.

c) Poles are not likely to fail spontaneously. See response to part (a) above.

OEB Staff Interrogatory # 111

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 2.4 Page: 2497-2498

(5.3.3 B) How the Plan Reflects Investment Planning and Asset Management

"Pole Replacement
Hydro One has extensive condition data on its pole population. Assets in poor condition have a higher probability of failure than assets in good condition."

Interrogatory:

a) Please provide data substantiating this claim, in detail.

b) Please provide the calculations used in the methodology.

c) How does this methodology account for the influence of weather events on pole failures, and are weather-related causes correlated to the pre-failure asset condition of the failed poles? Please provide a detailed explanation.

d) Please comment on the consequence of a single pole failure and the probability of the consequence. Compare this to the consequence of a cluster of pole failures and the probability of the consequence.

Response:

a) By definition, a pole in poor condition is one which has a reduced probability of resisting design loads applied to it, and thus has a higher probability of failure.

b) Hydro One assesses pole condition by performing a visual assessment, a hammer test, and/or a drill test to assess the approximate remaining strength. The CSA Group (formerly Canadian Standards Association) considers structures with less than 60% remaining strength no longer able to support the loads they were was designed for, as per CSA Standard C22.3 No. 1 Clause 8.3.1.3.

c) Hydro One designs its poles using the weather loading and load factors outlined in CSA Standard C22.3 No. 1.

d) A single pole failing will interrupt all of the customers downstream of that pole. Multiple poles failing in a row will interrupt the same number of downstream customers and will take longer to repair, however this event is less likely to occur.

OEB Staff Interrogatory # 112

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 2.4 Page: 2499
(5.3.3 B) How the Plan Reflects Investment Planning and Asset Management

"Distribution Stations
Hydro One operates 1,005 stations, of which 70 are in poor condition. Currently, 16 stations per year, on average (23% of those in poor condition) require a station outage. Each outage affects an average of 1,200 customers for 24 hours and contributes 4% to SAIDI and 3% to SAIFI. Because of the distributed nature of these stations, a failure has consequential impacts. For example, failures often require redirecting a mobile station from a planned replacement underway and increasing cost. Also, a station failure will affect an entire community and that has major impacts if it occurs in cold conditions in Northern Ontario.

- *Plan A proposed to replace all stations deemed to be in poor condition (70) by the end of the planning period (2022). SAIDI and SAIFI were forecast to improve by 14%."*

Interrogatory:

a) Please explain why the 16 identified substations each year require a station outage, and provide specific examples to illustrate.

b) Please explain how the performance results identified in this paragraph were calculated.

c) How often do spontaneous station equipment failures occur during the winter in northern Ontario?

d) How many of Hydro One distribution stations do not have Mobile Unit Substation capabilities and/or back-up supply from neighboring stations? Of those stations how many are deemed poor condition?

Response:

a) The reference to "16 stations per year, on average require a station outage"; was based on the number of unplanned transformer outages in 2016. Station outages due to transformer failures generally have the largest impact as they commonly take the longest time to restore power and affect the most customers. For details on transformer failures over the last 5 years, please refer to interrogatory response Exhibit I-24-Staff-156 part (a).

b) The performance results are approximate values that were derived using significant assumptions (number of customers and duration of outages). The values are for illustrative purposes and are intended to give a relative sense of the level of impact of the different investment categories. Updated values for station outage contributions to reliability have been provided in interrogatory response Exhibit I-17-EnergyProbe-17.

c) The Hydro One database classifies all customer interruptions resulting from equipment failures as "Defective Equipment," regardless of spontaneous or external causes. The database does not have the level of granularity to report spontaneous/autonomous equipment failures separately from outages where an external trigger initiated the equipment failure as stated in interrogatory response Exhibit I-20-Staff-69 part (b).

d) Hydro One has 22 stations that do not have MUS capabilities, dual transformers, a hot spare transformer or the ability to back-up supply from neighbouring stations. Of these 22 stations, 6 are deemed to be in poor condition.

OEB Staff Interrogatory # 113

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2622
(5.4.5.2) Attachments: Material Investments, ISD: SR-08 Distribution Lines PCB Equipment Replacement Program

*"**Risk Mitigation:***
The risk to completion of this investment as planned is based on the uncertainty of the volume and exact location of the PCB contaminated equipment exceeding the allowable threshold of 50 ppm. This risk is mitigated by the establishment of an inspection and testing program to identify all oil filled equipment that must be replaced under legislative requirement and an associated process to replacement the identified contaminated equipment."

Interrogatory:

a) Please provide the number of expected replacements for 2018-2022.

b) Please provide the number of remaining equipment to be replaced if the proposed investment is approved, allocated by equipment type.

Response:

a) Please see table below for the total number of lines PCB equipment to be replaced in each of the test years (2018 to 2022).

	2018	**2019**	**2020**	**2021**	**2022**
Planned Replacements	2,152	2,152	2,152	3,228	3,228

b) The remaining number of distribution lines PCB equipment to be replaced if the proposed 2018 to 2022 investment is approved would be approximately 4,300; comprised mainly of overhead pole mounted transformers. Hydro One anticipates to finish these remaining distribution lines PCB equipment replacements by year end 2024.

OEB Staff Interrogatory # 114

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2632-2634
(5.4.5.2) Attachments: Material Investments, ISD: SR-10 Distribution Lines Planned Component Replacement Program

Hydro One provided in the tables below the number of expected component replacements for the next five years and also the forecasted capital investment required.

	2018	2019	2020	2021	2022
Cross arms	1,780	1,780	1,780	1,780	1,780
Nest Platforms	15	15	15	15	15
Regulators and Reclosers	1,244	1,244	1,244	1,244	1,244
Transformers	100	100	100	100	100
Switches	60	60	60	60	60
Sentinels Lights	1,400	1,400	1,400	1,400	1,400

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	11.3	7.8	8.0	9.1	9.0	45.2
Less Removals	2.2	1.8	1.9	2.0	2.0	9.9
Gross Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**

**Includes Overhead at current rates.*

Interrogatory:

Please explain for 2018 why the capital investment is significantly higher for the same number of component replacement units.

Witness: GARZOUZI Lyla

Response:

Hydro One has identified an error in the unit table referenced in this interrogatory; please refer to revised table below.

	2018	2019	2020	2021	2022
Crossarms	1,000	1,000	1,000	1,000	1,000
Nest Platforms	15	15	15	15	15
Regulators and Reclosers	250	250	250	250	250
Transformers	30	30	30	30	30
Switches	30	30	30	30	30
Sentinel Lights	1,400	1,400	1,400	1,400	1,400

**Note: The units for 2021/2022 do not reflect the integration of the acquired LDCs.*

The apparent unit price discrepancy in 2018 is due to a $3 million increase in the line component replacement investment that was intended to fund Distribution Modernization activities by adding remote monitoring and control capability to a subset of electronic reclosers. This increase did not result in an update to the “Regulators and Reclosers” accomplishment level, as this refers to like-for-like replacement of hydraulic reclosers and not upgrades to electronic reclosers.

OEB Staff Interrogatory # 115

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2638
(5.4.5.2) Attachments: Material Investments, ISD: SR-12 Distribution Lines Sustainment Initiatives

Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule3 –S-12 Line Sustainment Initiatives

"Investment Need:
Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeder lines across the province with approximately 17% of these feeders lines being located off-road. These off-road sections of feeders are difficult to access during power interruptions and can result in increased risk of prolonged outages.

As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of its distribution feeder lines. These assessments have identified a number of concerns with the condition of the components on the primary feeders.
In addition to the condition of the distribution feeder line, there are a number of component installations that are of sub-standard design/construction based on changes over time in industry standards and do not meet current Hydro One standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks."

Interrogatory:

a) Please provide in Excel format the list of planned projects from EB-2013-0416 investment S-12 Line Sustainment Initiatives, including project name and total forecasted project cost.

b) Please provide in Excel format a list of projects completed under the line sustainment investment including the forecasted project cost, actual project cost, and explanation for material variances.

c) Please explain how this investment is coordinated with SR-10 Distribution Lines Planned Component Replacement program.

d) Please provide the business case for each project in 2018 to 2022 if available. If it is not available, please explain why there is no business case for each project. If it is available, it is expected that the business case(s) will include the identified issue, analytics of assets, feeder reliability, feeder capacity, number of customers affected, options considered, and cost of options.

Response:

a) Please see Attachment 1 Excel file for the list of planned projects from EB-2013-0416 investment S-12 Line Sustainment Initiatives, including project name and total forecasted project cost.

b) Please see Attachment 2 Excel file of material projects (exceeding $1 million) completed under the Line Sustainment Initiatives program in 2015, 2016, and 2017.

c) When identifying and prioritizing lines for refurbishment/rebuild, Hydro One takes into account the overall condition of poles, conductors, and associated components. Prior to finalizing the year ahead activities of the Distribution Lines Planned Component Replacement (SR-10) and Line Sustainment Initiatives (SR-12) programs, equipment defects identified in the SAP registry are reviewed to look for work bundling opportunities when applicable from the Lines Component Replacement (SR-10) program.

d) Hydro One's process is to initiate and approve business cases for project work; program work is approved with the business plan by the Board of Directors. The investments that are part of this ISD are program work only and therefore do not have a business case. Please refer to interrogatory response Exhibit I-24-CCC-25 for the 2016 Board of Directors material, as well as Exhibit Q, Tab 1, Schedule 1, Attachment 1 for the 2017 Board of Directors material.

Project Name (EB-2013-0416, Exhibit D2-2-3, S-12)	In-Service Year per EB-2013-0416	Planned Cost ($M) per EB-2013-0416
Bailey’s Corner DS F1 Rebuild, Sudbury	2015	1.3
Brant TS M21 Relocation, Simcoe	2015	1.5
Brockville TS 24M2 Relocation Phase 5 of 5, Brockville	2015	2.0
City of Owen Sound Refurbishment Phase 2 of 4, Owen Sound	2015	2.3
Duart TS M6 Relocation Phase 2 of 2, Kent	2015	2.3
Dymond TS M3 Rebuild, New Liskeard	2015	6.0
Manitouwadge TS M2 Rebuild, Thunder Bay	2015	6.5
Martindale TS 9M5 Relocation Phase 5 of 6, Sudbury	2015	2.1
Minden TS 87M2 Relocation Phase 1 of 6, Minden	2015	4.1
Otonabee TS 128M28 Relocation Phase 1 of 3, Peterborough	2015	2.0
Tilsonburg TS 20M10/Norfolk TS M3 Relocation, Simcoe	2015	4.3
City of Owen Sound Refurbishment Phase 3 of 4, Owen Sound	2016	2.2
Douglas Point TS Feeder Relocation, Walkerton	2016	3.0
Duart TS M5 Relocation, Kent	2016	3.9
Duart TS M6 Relocation, Strathroy	2016	1.2
Frontenac TS 8M3 Sub Cable Replacement, Kingston	2016	1.6
Kleinburg TS M8 Relocation, Bolton	2016	2.0
Martindale TS 9M5 Relocation Phase 6 of 6, Sudbury	2016	1.6
Minden TS 87M2 Relocation Phase 2 of 6, Minden	2016	1.7
Otonabee TS 128M28 Relocation Phase 2 of 3, Peterborough	2016	1.2
Reddendale DS Sub Cable Replacement, Kingston	2016	1.5
Terrace Bay Rebuild, Thunder Bay	2016	4.0
City of Owen Sound Refurbishment Phase 4 of 4, Owen Sound	2017	2.1
G3K Towerline Refurbishment, Kirkland Lake	2017	1.0
Kent TS M16 Relocation, Kent	2017	1.2
Larchwood TS M3 Relocation, Sudbury	2017	5.0
Manitoulin TS M25 Relocation, Manitoulin	2017	1.5
Minden TS 87M2 Relocation Phase 3 of 6, Minden	2017	2.0
Napanee TS 27M2 Relocation Phase 1 of 2, Picton	2017	3.0
Otonabee TS 128M28 Relocation Phase 3 of 3, Peterborough	2017	1.5
Sidney TS 12M7 – Back Up Supply, Frankford	2017	6.0
Sidney TS 12M7 – Wooler Rd. x Smithfield DS Relocation, Frankford	2017	1.3
Wanstead TS M4 Relocation (Brigden DS) Phase 1 of 2, Lambton	2017	1.0
Havelock TS 57M1 Apsley to Eel’s Lake RS Relocation, Bancroft	2018	3.5
Havelock TS 57M2 Relocation Phase 1 of 2, Tweed	2018	2.5
Minden TS 87M2 Relocation Phase 4 of 6, Minden	2018	2.0

Project Name (EB-2013-0416, Exhibit D2-2-3, S-12)	In-Service Year per EB-2013-0416	Planned Cost ($M) per EB-2013-0416
Morrisburg TS 18M26 Relocation, Winchester	2018	4.0
Napanee TS 27M2 Relocation Phase 2 of 2, Picton	2018	3.0
Picton TS 28M5 Relocation Phase 1 of 2, Picton	2018	3.0
Wanstead TS M4 Relocation (Brigden DS) Phase 2 of 2, Lambton	2018	1.0
Dobbin TS 20M6 Relocation, Peterborough	2019	2.5
Duart TS M24 Relocation, Kent	2019	1.9
Flynn’s Corners DS F3 Phase 1 of 2, Bancroft	2019	1.8
Havelock TS 57M2 Relocation Phase 2 of 2, Tweed	2019	2.5
Lindsay TS D4M7 Relocation Phase 1 of 2, Fenelon Falls	2019	2.0
Longueuil TS 26M23 Relocation, Vankleek Hill	2019	3.5
Minden TS 87M2 Relocation Phase 5 of 6, Minden	2019	2.0
Picton TS 28M5 Relocation Phase 2 of 2, Picton	2019	3.0
Timmins 25 Hz Line Removals, Timmins	2019	1.0
Wallace TS 16M1 Relocation Phase 1 of 2, Bancroft	2019	2.5
Whitefish DS F1 Rebuild, Sudbury	2019	1.8

Project Name	Year Complete	Forecast Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation
Duart TS M6 Relocation Phase 2 of 2, Kent	2015	2.3	3.5	1.2	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work
Otonabee TS 128M28 Relocation Phase 1 of 3, Peterborough	2015	2.0	2.5	0.5	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work
Timmins Underground Vaults	2015	5.3	5.1	-0.2	N/A
Brockville 24M2 Phase 3	2015	2.8	3.2	0.3	N/A
Murillo DS F1 Relocation	2015	1.5	2.2	0.7	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work
Manitouwadge TS 13M2 Rebuild-Phase 1 - Hornepayne to Mill	2015	1.6	2.1	0.5	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work
Meaford TS M1 Relocation	2015	2.8	2.0	-0.7	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work
Minden TS 87M2 Feeder Relocation	2016	6.1	6.2	0.1	N/A
Manitouwadge TS 13M2 Rebuild - Phase 2	2016	4.2	4.3	0.1	N/A
Havelock TS 57M4 Relocation	2016	3.1	3.2	0.1	N/A
Martindale TS 9M5 Relocation Phase 5 of 6, Sudbury	2017	2.1	3.2	1.1	Estimate completed at time of filing were high-level in nature, without having completed engineering, design and customer engagement work

OEB Staff Interrogatory # 116

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2645
(5.4.5.2) Attachments: Material Investments, ISD: SR-13 Life Cycle Optimization & Operational Efficiency Projects

Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-05 Asset Life Cycle Optimization and Operational Efficiency

"Alternative 2: Modify The Distribution System to Eliminate Operationally Inefficient Assets that are Nearing End-of-Life (Recommended)
Address specific end-of-life asset needs by means other than like-for-like where there are opportunities to reduce costs and achieve increased operational efficiencies. When stations or lines are approaching their end-of-life based on the condition of their individual components, there may be opportunities to implement system changes other than like-for-like replacement of these assets in order to achieve cost savings and long term operational efficiencies. It may be possible to eliminate stations or consolidate line assets through voltage conversion projects, or transfers to other stations. Reduced upfront capital costs as well as future maintenance savings can be realized using this approach."

Interrogatory:

a) Is a business case available for each of the projects listed? If no, please provide an explanation as to why not. If yes, please provide the business case(s). It is expected the business case(s) will address the following items:

- List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
- Reliability metrics for stations and feeders involved in each project
- Station and feeder capacity
- Number of customers affected

- Proposed options, including scope of work, benefits, costs, and expected efficiency savings

b) Has Hydro One considered other alternatives that are not referenced in this description?

c) There are several projects in EB-2013-0416 D-05 - Asset Life Cycle Optimization and Operational Efficiency for the years 2015-2017 that are repeated in SR-13. Please explain why these projects were not completed and where the approved capital was redirected.

Response:

a) No. A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. At this point in time, most of the Life Cycle Optimization & Operational Efficiency Projects listed in exhibit ISD SR-13 are planned to be in service at a future date beyond which necessitates the production of a Business Case for the purpose of authorizing the expenditure of funds for execution. Business Cases that are available can be found as attachments to this Exhibit (Attachments 1 and 2).

b) Yes, Hydro One also considers addressing the specific end-of-life asset needs through station decommissioning by constructing new stations/feeders to meet the existing system needs. This alternative is explained in ISD SR-13 Life Cycle Optimization & Operational Efficiency Projects under the section titled "Station Decommissioning by Constructing New Station/Feeders."

c) These projects were not completed as capital was redirected to other higher priority capital investments through Hydro One's Investment Planning Process. DSP Section 2.1 presents Hydro One's Investment Planning Process in detail. As described in DSP Section 2.1 page 1, this process occurs on an annual basis: "Hydro One's planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board's filing requirement of a consolidated five-year capital plan. All investments follow this same process." The redirected capital for these projects funded part of Hydro One's total 2015 and 2016 actual and 2017 forecast capital expenditures. DSP Section 3.6 summarizes the result of implementing the cyclical investment planning process. DSP Section 3.6.1 summarizes the variances between forecast and historical budgets by OEB Investment Category.

hydro one

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

Investment Name: Bradford DS F3 - Reinforcement		Claim #: 51001165
AR:24484	Investment Driver: D.C.2.0.2	In-service Date: Nov 1, 2017
This Approval: $406k	Previous Approval: $0k	Total Approval: $406k

Investment Summary:
This request is for $406k, to construct a new pole line along 10 Sideroad, between 6th Line and 5th Line.

The Township of Bradford West Gwillimbury is in the process of constructing a new arterial roadway to the east of Hwy 400, between 5th Line and 6th Line. This arterial roadway is associated with the introduction of new commercial and industrial developments which will flank Hwy 400 between 5th Line and 9th Line. At present, there is insufficient capacity at Bradford DS to support the anticipated growth.

The newly constructed pole line will be designed with sufficient height for two (2) 27.6kV circuits, and one (1) 44kV circuit. One of the feeder positions will be used to maintain the existing 8.32kV circuit from Bradford DS F3. The remaining 27.6kV circuit position will be used for an eventual tie point between the 27.6kV feeders from Doane DS F2 and Holland DS F1, which will be required to support planned growth for the area west of Bradford. Inclusion of pole height for 44kV overbuild is also anticipated to be required for future commercial / industrial loads on the lands abutting Hwy 400.

Other Alternatives Considered

Status Quo: The do-nothing approach is not a viable option since Hydro One will be limited in its ability to connect new customers.

Alternative 1: Construct a new pole line along 10 Sideroad, between 6th Line and 5th Line. The new pole line will be framed for double-circuit 27.6kV, with sufficient pole height for 44kV overbuild.

Benefits

This investment will ensure Hydro One is positioned to support growth in the Bradford area, by reinforcing the Bradford DS F3 feeder. This will maintain Hydro One's ability to connect new customers, and will prepare the pole line for the introduction of 27.6kV to the area.

Cost

(in $K)	2016	2017	Total
Capital & MFA	-	$357k	$357k
OM&A and removals	-	$49k	$49k
Gross Investment Cost	-	$0k	$0k
Recoverable	-	$0k	$0k
Net Investment Cost	-	$406k	$406k

Note: Not for use for projects $1 Million or greater. Include all previous approvals

Project Risk Assessment

This project is in the 2017-2022 Accomplishment File, with sufficient funding (AIP005917).

Multiple significant projects are pending for the Newmarket area. Staff resourcing could therefore be an issue, dependent upon project / customer timing.

Signature Block

Prepared & Recommended by: Mark van Tol	Title, Department: Dx Investment Planner	Signature:	Date: Jan 10 2017.
Approved by: Ted Lyberogiannis	Title, Department: Manager, Dx Investment	Signature:	Date: Jan 10'17

Scientific Research & Experimental Development Tax Credits (SR&ED):
Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No
Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

Author: Mark van Tol
Date: Jan 2, 2017

Dresden DS Conversion

Overview of Recommended Alternative:

Approval for $2,800K is requested to proceed with removing Dresden DS and converting existing 8.32kV customers to 27.6kV. This total includes $205K, approved in January, 2017 to prepare a detailed estimate.

Investment Details:

In-service: Nov 30th, 2019

Dresden DS located in Chatham-Kent, is amongst the worst transformers in the province from a condition perspective, and is at risk of failure, due to moisture leaking into the station transformer. Due to the loading of the Dresden DS 8.32kV feeders, and relative proximity of customers to existing 27.6kV lines, Asset Management has determined that conversion in lieu of refurbishment is the most cost effective option. Furthermore, converting to 27.6kV will make the supply adequate for upcoming load growth in the area.

The Distribution system modifications will be undertaken in two dependent phases, so as to reduce the impact of outages on customers:

- Phase 1 involves new overhead distribution line construction of 3km, to convert existing 8.32kV customers to 27.6kV.

- Phase 2 involves additional overhead line construction of 1.5km, to convert the remaining customers on Dresden DS to 27.6kV, and removal of Dresden DS.

The total cost for both phases is currently expected to be approximately $2,800K. Not proceeding with this investment will mean that customers continue to be exposed to a poor performing Dresden DS, and a distribution system that would not be adequate for future growth.

Benefits:

This investment provides an opportunity to remove an end of life asset, and increase system capacity, while minimizing the outage impact to our customers.

Estimated Costs & In-service:

The in-service date of the entire project is November 2019, with Phase 1 assets projected to be placed in-service by June 2018. The cost breakdown is as follows:

Category	Cost
Previous Approvals	$205K
Construction of 4.5km overhead Dx line and conversion costs	$1,460K
Contingency	$146K
Interest/Overhead	$355K
Removals	$634K
Total	$2,800K

Phase 1 construction costs are $1,300K of the total cost and are based on an estimate with an accuracy of +/- 10%. The remainder of the total cost is for Phase 2 construction, which is based on a planners estimate with an accuracy of +/- 50%. Detailed estimate for Phase 2 is expected to be completed by Nov 2018. This project construction Phase 1 will need to begin in early 2018, prior to completion of the Phase 2 component of the estimate, because the necessary resources are available.

This investment is included in the approved 2017-2022 investment plan and the draft 2018-2023 investment plan with total funding of $2,900k, including $300k in 2018 and $2,600k in 2019. Any capital expenditure variances will be managed within the Distribution Capital Driver envelope through redirection of funds from other projects.

Other Alternatives Considered

Status Quo or Do nothing Alternative

The status quo option was rejected, as the transformer is end of life, and at risk of failure.

Alternative 2 – Refurbishment of Dresden DS

Alternative 2 was not considered further; as it has a similar capital cost ($2.5-$3.0M), with additional maintenance costs for station inspections and equipment repairs of $30k/year, and it does not address future system capacity needs.

Regulatory Considerations

This investment is included in Hydro One's Distribution rate application (2018-2022) currently before the Ontario Energy Board for approval, with in-service additions totaling $2.6M in 2019. This BCS is projecting the cost to be in line with that forecast in the rate filing, however with some in-service timing differences. Any variances will be managed through the Redirection Process.

Hydro One considers the risk of non-recovery of these expenditures to be low because this investment will increase the quality of Hydro One's distribution system, meet our obligations to customers under the Distribution System Code and eliminate operational risks associated with operating end-of-life assets.

Risks and Mitigation

Soil Contamination – The cost of the 2nd phase of the construction is based on a planners estimate (+/- 50%). The environmental assessment for station removal costs has not been completed at this time. If the detailed estimate discovers major environmental work in the Dresden DS area, the cost could increase by $140K.

This Approval ($): $2,595k	Previous Approval ($): $205K	Total Approval ($): $2,800k
Signature Block:		
Approved by: Ted Lyberogiannis	**Title:** Manager, Dx Investment Planning	**Date:** Nov 10 '17
Approved by: Wade Frost	**Title:** Manager, Decision Support	**Date:** Nov 10/17
Approved by: Lyla Garzouzi	**Title:** Director, Dx Asset Management	**Date:** Nov 10, 2017

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($k)	2017($k)	2018($k)	2019($k)	Total ($k)
Capital* and MFA	5	242	919	1,000	2,166
OM&A and Removals	-	5	127	502	634
Gross Investment Cost*	5	247	1,046	1,502	2,800
Recoverable	-	-	-	-	-
Net Investment Cost	5	242	919	1,000	2,166

*Includes capitalized interest and overhead at current rates

Rate base additions

	2018($k)	2019($k)	Total($k)
In-Service $ Additions (BCS)	1,016	1,150	2,166
In-Service $ Additions – Rate filing (Dx 2018-2022)	255	2,297	2,552
Variance	761	(1,147)	(386)
Redirection/Available	Redirection	Available	Available for Phase 2

In-service Date:	Nov 30th, 2019
Business Case Summary #:	51002347
Appropriation Request #:	24444
Subject ID #	81235
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Lyla Garzouzi
Planner	Usman Shaheen

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

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

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

OEB Staff Interrogatory # 117

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2780

(5.4.5.2) Attachments: Material Investments, ISD: GP-18 Integrated System Operating Centre

"Alternative 6: (Recommended) Initiate Build of the Integrated System Operations Centre (ISOC).

This alternative provides for:

1. *a Network Operating Control Centre;*
2. *a Backup Control Centre for the Integrated Telecommunications Management Centre; and*
3. *primary facilities for Security Operations.*

This Alternative also includes the provision for a shared integrated Data Centre, all critical support infrastructures at the preferred site. This alternative will maximize Operational flexibility for Hydro One Networks and associated lines of business while eliminating the need to duplicate investments in multiple sites, and costly critical support infrastructure (emergency generators, uninterrupted power supplies, telecommunications etc.). The total distribution share of this option is estimated to be $64.6M, and the specific amount for this plan period would be $56.4M.

The ISOC strategy will enable a "Dual Primary" scenario where both Centres can be live as compared to the current live/passive (standby) model. Functionality required to facilitate this strategy is not expected until 2022 and will be implemented within current/future lifecycle schedules for the primary applications (i.e. ORMS, DMS, NMS etc.). This effectively negates the need to prematurely replace, re-architect and implement newer systems prior to their lifecycle expiration while providing the benefits and future flexibility of Primary Control ability."

Interrogatory:

a) Please provide the basis and calculation in support of the 50.07% cost allocation to distribution.

b) Did the distribution system need this distribution specific equipment previously? If not, what has changed in the distribution system to cause the need for this equipment.

Response:

a) Hydro One has used the approved Black & Veatch Common Asset Allocation methodology in order to allocation the costs between Transmission and Distribution. The Common Asset Allocation study is referenced in Exhibit D1, Tab 4, Schedule 1.

b) Yes, the distribution system needed this distribution-specific equipment previously.

   In Hydro One's previous Distribution rate filing EB-2013-0416, ISD O-04 *New Facility Development* was proposed to build a new Network Operating Control Centre to replace the aging Back-Up Control Centre. Concerns with the aging Back-Up Control Centre had been noted to the OEB in Hydro One's rate filing material going back to 2009.

OEB Staff Interrogatory # 118

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

Reference:
B1-01-01 Section 1.4-A01 Page: 1918

(5.2.3) Performance Measurement and Outcome Measures, Table 8 – Distribution OEB Scorecard.

Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 9)

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (5.3.3) Key Component Summaries – Distribution Stations, Figure 17 – Demographics of Distribution Station Transformers, Page 2417.

The Auditor General's report recommended the following:
"In order to improve the reliability ratings for its distribution system, Hydro One should:

- *establish more ambitious performance goals, targets and benchmarks for system performance; and*
- *develop short- and long-term strategies for new and enhanced activities and cost-effective investments that will improve its overall reliability record. "*

In Table 8 the historical unit cost for Station Refurbishment per MVA jumped significantly between 2014 and 2015.

Interrogatory:
a) Please explain the reasons for this significant increase in unit cost.

b) If the cost increase is due to adding station capabilities, please explain Hydro One's justification in allocating spending in increased station capabilities instead of meeting the need to refurbish 41% of stations as shown in Figure 17.

Response:

a) In Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4, Table 8 – Distribution OEB Scorecard, the 2015 *Station Refurbishments – Gross Cost per MVA in $* was reported as $500,000 – an increase of about 44 per cent compared to the 2014 reported value. The increase was primarily due to the average size in MVA of the transformer banks installed.

   In 2014, 7 transformer banks were installed and the average size was 7.1 MVA per transformer bank. In 2015, 21 transformer banks were installed and the average size was 5.6 MVA per transformer bank. In 2015, the average size of the transformer at each site was smaller; therefore the cost per MVA was higher.

b) The unit cost increase between 2014 and 2015 was not due to adding station capabilities.

OEB Staff Interrogatory # 119

Issue:

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

Reference:

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

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

The Auditor General's report recommended the following:

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

Interrogatory:

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

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

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

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

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

Response:

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

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

Demographics Risk Factor:

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

Condition Risk Factor:

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

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

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

<u>Criticality Risk Factor:</u>

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

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

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

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

OEB Staff Interrogatory # 120

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 2.2 Page: 2394
(5.3.2) Overview of Assets Managed
Office of Auditor General of Ontario – Annual Report 2015 (Rec. 12)

The Auditor General's report recommended the following:"To reduce the risk of equipment failures that can cause power outages on the distribution system, Hydro One should:

- *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"*

Interrogatory:

a) Has Hydro One compared the typical useful life for all assets under the Overview of Assets Managed section to other distribution companies and justified variances? If so, please provide the analysis. If not, why not?

b) With the ever-increasing group of assets reaching end-of-life and limited resources, please provide Hydro One's asset replacement philosophy or strategy and provide examples in the current capital plans of each.

Response:

a) Comparison and discussions of specific Hydro One assets life expectancy to other distribution utilities are found in the benchmarking studies filed as part of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1):
   i. Poles: DSP Section 1.6, Attachment 1, page 12
   ii. Stations Equipment: DSP Section 1.6, Attachment 1, pages 21-24
   iii. Vegetation Rights-Of-Ways: DSP Section 1.6, Attachment 2, page 25

b) Hydro One's asset replacement strategies are discussed in detail in Table 36 of Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.

Witness: GARZOUZI Lyla

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

Vulnerable Energy Consumers Coalition Interrogatory # 21

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:

A-03-01-03 Page: -(Auditor General Report 2016 Follow-up)

In her 2015 Report the Auditor General made the following comment with respect to Hydro One's implementation of its capital plan:

Hydro One not replacing very high-risk assets, contrary to its rate applications: *We found Hydro One was not replacing assets it determined were in very poor condition and at very high risk of failing, and it used these assets in successive rate applications to the Ontario Energy Board to justify and receive rate increases. Power transformers that are identified as being in very poor condition should be replaced at the earliest time possible; however, Hydro One replaced only four of the 18 power transformers it deemed to be in very poor condition in its 2013-2014 (2015 Report page 248)*

Interrogatory:

a) Please explain what steps Hydro one has taken to address this criticism.

b) Specifically please explain what reporting Hydro One proposes to make to the Ontario Energy Board so as to provide assurance that the DSP presented to the Board is this proceeding is in fact substantively implemented as planned?

Response:

a) This specific comment relates to Hydro One's transmission power transformers and the Auditor General addressed this concern in more detail in Recommendation #3. Hydro One's response on this criticism is addressed in the published Auditor General's 2015 Annual Report.

b) In addition to the OEB's mandatory Electricity Distributor Scorecard, please see section 1.4 of the DSP (Exhibit B1, Tab 1, Schedule 1) for Hydro One's Distribution Scorecard, which contains the performance measures that Hydro One proposes to report on.

Witness: KIRALY Gregory

Vulnerable Energy Consumers Coalition 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:

A-03-01-03

Interrogatory:

a) What are the costs (by recommendation) in years 2017 through 2023 of addressing the Auditor General's concerns as set out the Hydro One's Internal Audit Report by AG Recommendations 1 through 17?

Response:

a) Through addressing the Auditor General's concerns, Hydro One has incorporated these recommendations into its processes as ongoing activities and continuous improvement. It is not possible to provide specific costs associated to these recommendations.

Association of Major Power Consumers in Ontario Interrogatory # 17

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6-A02 Page: 14 – Vegetation Management Study

Interrogatory:

a) Page 14: Please provide the underlying calculation of Hydro One's cost per customer for UVM for each of the years 2011 to 2015 and provide the calculation for 2016 and 2017.

b) Page 14: With the exception of one other North American company, Hydro One has the lowest average customer density in land area. Please provide the average cost per customer spent in 2011-2015 for UVM for the one other North American company.

c) Page 14: For the one other North American company, please provide the trees per system km.

Response:

a) $99.36 is the average annual cost per customer for the 2011-2015 period. This is a calculated metric based on the number of customers in 2015 and the total UVM costs. The following are the calculated average costs per Hydro One customer for each of the years between 2011-2015. We do not have this information for 2016-17.

2011	2012	2013	2014	2015	5-year Average
$96.25	$103.13	$101.96	$106.27	$89.17	$99.36

b) $10.32/customer.

c) This utility did not provide the number of trees on their system.

Association of Major Power Consumers in Ontario Interrogatory # 18

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6-A03 Page: 5-10 – Gartner IT Budget Assessment

Interrogatory:

a) Please provide the date of the final report.

b) Page 5: Please provide the dates that correspond to the five components of the IT Spending Benchmark Project Plan.

c) Page 6: Gartner indicates the analysis period was 2015. Please explain the basis for a 2015 analysis period. Please explain why 2016 and historical years were not included so that a trend analysis could be done.

d) Page 6: Please provide the individual peer group profile data at the same level of detail as shown for Hydro One.

e) Page 8: Please confirm the information shown on Page 8 (PDF Page 2285 of 2850) reflects Hydro One Distribution.

f) Page 10: Summary of Metrics – Please provide a table that sets out a summary of the metrics for each organization in the peer group compared to Hydro One.

g) Page 10: Please provide a summary of the metrics for Hydro One for the years 2012, 2013, 2014, 2016 and forecast 2018 to 2022.

h) Page 10: Please explain if Gartner has metric data for peer companies for years prior to 2015. If yes, please provide.

Response:

The following responses were provided by Gartner.

a) 28 July 2016

b) Dates for five components:
   a. Project Initiation: 9 May 2016
   b. Data Collection: 13 June 2016
   c. Data Validation: 30 June 2016
   d. Analysis: 14 July 2016
   e. Deliver Results: 28 July 2016

c) Hydro One commissioned an IT Budget Assessment from Gartner in May 2016. This is a standard offering from Gartner. The IT Budget Assessment uses a single annual budget period for comparison and does not include trending for prior years. Since the IT Budget Assessment commenced in May 2016, Hydro One determined with Gartner that 2015 financial data should be used.

d) Providing the individual peer group information is not possible due to Gartner contractual confidentiality restrictions and assurances to protect client anonymity and data.

e) The IT Budget Assessment study was for Hydro One Limited.

f) Providing the individual peer group information is not possible due to Gartner contractual confidentiality restrictions and assurances to protect client anonymity and data.

g) Gartner cannot provide this information as it only has the 2015 information from Hydro One.

h) Gartner does not have all of the metric data for peer companies prior to 2015.

Association of Major Power Consumers in Ontario Interrogatory # 19

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 1.6-A01 Page: 17-27

Interrogatory:
a) Page 17 – Please explain further the need for Hydro One to improve its use of testing results and maintenance history records in making replace versus repair decisions for certain substation equipment. In the response please describe the types of improvements required, and the expected outcomes of these improvements.

b) Page 22 – For each of the 10 comparator groups in Figure 25, please provide the number of power transformers.

c) Page 26 – Please explain why Hydro One does not evaluate testing results and/or maintenance history records as a primary driver when making replace versus repair decisions for switching and protection equipment or relays.

d) Page 26 – Please explain how visual inspections are a reliable driver in making replace versus repair decisions.

e) Page 26 – Please explain how Hydro One evaluates poor performance in Breakers and Bus Ties and Relays and Control Wiring.

f) Page 26 – Please explain Hydro One's unique situation regarding the use of safety concerns as an important evaluation factor when evaluating switching and protection equipment.

g) Page 26 – Please explain how switching equipment, protection equipment and relays drive Substation Rebuilds projects.

h) Page 27 – Please provide Hydro One's response to the Recommendations on Page 27 for pole replacement and substation refurbishment.

i) Page A-1 – Please provide a list of the companies contacted that declined to participate.

j) Page A-1 – Please provide the identification number that corresponds to each company in Figure 30.

k) Page A-1 – Please list the top three companies that compare closest to Hydro One and provide their comparator number.

Response:

a) Testing results and maintenance history records provide indications of asset health. Analysis and trending of testing results and maintenance activity over time can provide objective evidence that a particular asset is approaching the end of its practical service life. By formally incorporating available data on testing results and maintenance history into an asset health scoring index, a company can more objectively prioritize its asset replacement and/or major asset refurbishment plans across its total asset portfolio.

b) The number of power transformers for the companies in Figure 25 is shown below, ranked in order of highest to lowest. Providing the ID code numbers for each of the listed number of transformers would have the effect of identifying many of the companies, which is precluded by the confidentiality agreements that enabled the data collection.

Power Transformers
1,590
1,163 (Hydro One)
616
466
245
172
85
59
54
34

c) Please refer to Exhibit I-25-Staff-128 parts a), b) and c).

d) Visual inspections are normally performed when equipment is taken out of service for maintenance. A trained maintenance technician can make reliable judgements on the cost of repairing any visible damage and the timeframe over which the equipment will perform effectively after such repairs are completed. Those estimates can then be factored into a repair versus replace cost-benefit analyses for a particular unit of equipment or for a group of similar assets (e.g., equipment from the same manufacturer of the same design and age vintage).

e) Hydro One evaluates the performance of breakers, reclosers and associated protection relays that control them, based on their ability to open or close when required. Failed protection relays or control wiring, as well as breakers or reclosers which fail to open or close when required are considered to be poor performers. Hydro One Distribution has a very small population of bus tie switches, and does not have any bus tie breakers or bus tie reclosers.

f) Hydro One has observed that certain models of switches have been more prone to break and fall when manually operated. Hydro One replaces these switches within SR-04: distribution station planned component replacement program. The replacement of these switches are bundled with condition based maintenance work at the stations to mitigate the risk of switches falling on Hydro One staff.

Hydro One Distribution performs short circuit studies to ensure that maximum short circuit levels on a feeder are not exceeding the interrupting capacity of the reclosers. Similar studies are performed to ensure that reclosers and fuses are correctly sized and have adequate timing curves to provide sufficient equipment protection and coordination. Hydro One considers the discovery of incorrectly sized protection equipment a safety concern which must be addressed upon discovery. This can involve the upgrade of reclosers to those with higher short circuit interrupting levels through capital investment.

g) Typically, the condition of switching equipment, protection equipment and relays does not drive decisions to rebuild substations. More often, component focused projects are initiated to replace or repair those components if they are determined to be in poor condition or technologically obsolete. However, if a utility is considering the replacement of larger and more expensive substation components such as power transformers, breakers and bus-work due to equipment condition and/or or loading concerns, it may also choose to include replacement or repair of switching equipment, protection equipment and/or relays within the scope of either a station-centric or full station rebuild project. Such bundling of work is often a more cost effective and efficient approach under these circumstances compared to separate replacement or repair of equipement on failure.

h) Please see Hydro One's response in Exhibit I-25-Staff-126.

i) The table below shows most of the invited companies who chose not to participate. The column on the left shows those who participated in recent First Quartile studies, and the right column shows companies who were contacted specifically for this study. The table is incomplete, because complete notes were not kept of all the companies invited to participate.

1QC Participants	**Specific for Hydro One study**
Arizona Public Service	Algoma Power (Ontario LDC)
East Kentucky Power Cooperative	ATCO Electric
Exelon - BGE	AvanGrid
FirstEnergy	Entegrus Powerlines (Ontario LDC)
PSEG-Long Island	FortisOntario
Hydro Quebec	Greater Sudbury Ontario (Ontario LDC)
Rochester Gas & Electric	Horizon (Niagara Peninsula)
New York State Gas & Electric	Hydro Ottawa
Central Maine Power	Manitoba Hydro
	National Grid
	New Brunswick Power
	Nova Scotia Power
	Pacific Gas & Electric
	PPL Electric
	SaskPower

j) Data, transmitted by companies other than Hydro One, was provided to Navigant and First Quartile was under strict confidentiality requirements. To obtain the data, Navigant and First Quartile are required to anonymize individual company results and disclose only summary metrics.

k) There is no single measure to determine comparability of two companies. Hydro One shares characteristics with all the companies in the peer group.

Association of Major Power Consumers in Ontario Interrogatory # 32

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.3

Interrogatory:

a) Page 1: As a result of the two benchmarking studies related to pole replacement and station refurbishment, please quantify the changes to each investment in 2018 that are the direct result of each benchmarking study.
b) Page 4: Please identify any Regional Planning Projects listed that were deferred from EB-2013-0416 and explain the timing differences and the reason for the deferral.
c) Page 5: Please identify any Distribution Planning Activities listed that were deferred from EB-2013-0416 and explain the timing differences and the reason for the deferral.
d) Page 6: Please identify any Distribution Requests listed that were deferred from EB-2013-0416 and explain the timing differences and the reason for the deferral.
e) Page 10: Please provide the trend in Hydro One's fleet utilization in the past 15 years.
f) Page 12: Please provide Hydro One's overall asset replacement rate for the years 2012 to 2017 and forecast for 2018 to 2022.

Response:

a) Please refer to interrogatory response Exhibit I-25-Staff-126 for Hydro One's actions related to the benchmarking study. As a number of these actions are in progress, the associated costs can not be quantified until they are completed.

b) Please see the table below for Regional Planning projects included in this Distribution System Plan that were deferred from EB-2013-0416. These projects were deferred to reflect the refined need dates determined through the associated Regional Planning processes, none of which had been completed at the time of the EB-2013-0416 application.

Project ID	Project Name	In-Service Date (EB-2013-0416)	In-Service Date (EB-2017-0049)	Region
ISD GP-25	Leamington TS Capital Contribution	2017	04/2018	Windsor-Essex
ISD SS-02 *(LG-14)*	Leamington TS Feeder Development	2017	06/2019	Windsor-Essex
ISD GP-26	Hanmer TS Capital Contribution	2016	02/2019	Sudbury/Algoma
ISD SR-11 *(LC-10)*	Hanmer TS Feeder Development	2017	02/2019	Sudbury/Algoma
ISD SS-02 *(LG-24)*	Muskoka TS M5 x M1 Feeder Tie	2018	12/2019	Southern Georgian Bay/Muskoka

c) See table below for the Distribution Planning Activities included in this Distribution System Plan that were deferred from EB-2013-0416.

Project Name	EB-2013-0416		EB-2017-0049		Reason for Deferral
	ISD #	Planned Year(s)	Project ID	Planned Year(s)	
Devlin DS F1 3 Phase Upgrade	D-02	2016	LG-2	2018	Deferred due to reprioritization
Orangeville TS M3 - Mayfield West Line Extension	D-02	2017	LG-4	2018	Deferred due to reprioritization
Armitage TS M22 Extension	D-02	2016	LG-9	2018-2019	Deferred due to reprioritization
City of Owen Sound Tie - Line Reinforcement	D-06	2016	LG-10	2018-2019	Deferred due to reprioritization
Grand Bend DS F3 Voltage Conversion	D-02	2016	LG-12	2018-2019	Deferred due to reprioritization
Manotick DS Feeder Development	D-02	2015	LG-15	2018-2019	Load did not materialize
Stouffville 10th Line DS New T3 & Feeder	D-02	2016	LG-16	2018-2019	Deferred due to reprioritization
Twelve Mile Bay DS - New Station & Feeders *(encompassing formerly New Station – Twelve Mile Bay DS and Twelve Mile Bay Submarine Cable projects)*	D-02	2016	LG-18	2018-2019	Deferred due to external factors
Beckwith DS F3 Feeder Development	D-02	2017	LG-19	2019	Deferred due to reprioritization
Kirkland Lake Voltage Conversion-Part 2 *(formerly called Woods DS Voltage Conversion project)*	D-02	2017	LG-21	2019	Deferred due to reprioritization

Project Name	EB-2013-0416		EB-2017-0049		Reason for Deferral
	ISD #	**Planned Year(s)**	**Project ID**	**Planned Year(s)**	
Rockland DS T2 Transformer	D-02	2018	LG-25	2019	Deferred due to reprioritization
King City DS - New Station & Feeders *(encompassing formerly King City New Feeder Development, and New Station - King City DS)*	D-02	2018	LG-29	2019-2020	Deferred due to reprioritization
New Old School DS *(encompassing formerly Old School DS New Feeder Development, and New Station – Old School DS)*	D-02	2018	LG-30	2019-2020	Deferred due to reprioritization
Greely DS F1 Feeder Development	D-02	2018	LG-32	2020	Deferred due to reprioritization
Kirkland Lake Voltage Conversion-Part 3	D-02	2018	LG-33	2020	Deferred due to reprioritization
Perth Area Upgrades	D-05	2019	LG-36	2020	Deferred due to reprioritization
Dunchurch DS F2 - Extend to Magnetawan	D-02	2017	LG-39	2021	Deferred due to reprioritization
Kleinburg TS M26 extension to Mayfield West	D-02	2019	LG-41	2021	Deferred due to reprioritization
Ancaster West DS Transformer Upgrade	D-02	2016	LG-44	2021-2022	Load did not materialize
Point Au Baril DS F2 Extension	D-02	2016	LG-47	2021-2022	Deferred due to external factors

d) Based on the reference provided in the question, it appears to be related to the list of distributed generation connections requests on page 6. There were no distributed generation connections requests that were deferred from EB-2013-0416.

e) As stated on page 8 in Exhibit C1, Tab 3, Schedule 1, Attachement 2, Hydro One’s equipment utilization averages have increased from approximately 65% in 2001 to approximately 80% in 2016.

f) Hydro One does not have an overall asset replacement rate. Replace rates are utilized in determining investments for only a subset of assets. Please refer to interrogatory response Exhibit I-24-AMPCO-25 for the asset specific replacement rates.

Building Owners and Managers Association Toronto Interrogatory # 56

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

A-03-01-04 Page: 5 2015 Data Remediation Project

Interrogatory:

What is the process for acquiring the required additional data for storing it, and for making it available to the staff who require it?

Response:

The data is collected as part of maintenance activities via mobile tablets and stored in the central SAP system; thereby making the data available for all staff that require the information.

Witness: JESUS Bruno

Building Owners and Managers Association Toronto Interrogatory # 107

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 127

Interrogatory:
What is the OM&A expenditure that matches Scenario 1? What was its net total to customers?

Response:
Please refer to Exhibit B1, Tab 1, Schedule 1, p.1696, Scenario 1, OM&A.

Building Owners and Managers Association Toronto Interrogatory # 110

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 132

Interrogatory:
Why did you not focus on OM&A and possible reductions to OM&A as presentations?

Response:
The OM&A levels associated with each of the three scenarios were presented at the Customer Engagement Workshops. Please refer to Exhibit B1, Tab 1, Schedule 1, pp. 1696-1697.

Building Owners and Managers Association Toronto Interrogatory # 111

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 127

Interrogatory:

Why did OM&A go up along with capex in the improving performance scenario? Potential efficiencies were not mentioned – different levels of reduction.

Response:

OM&A increases in the improving performance scenario are to address vegetation caused outages. Please refer to Exhibit I-23-Staff-079 for information on the different scenarios.

Building Owners and Managers Association Toronto Interrogatory # 112

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 133

Interrogatory:

What the relationship between capital expenditures did maintenance expenditures set out?

Response:

Hydro One does not understand the question.

Building Owners and Managers Association Toronto Interrogatory # 113

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 133

Interrogatory:

Why did the Company not provide more detail on both capital and maintenance and OM&A? Why is this not a large planning cycle 10-15 years?

Response:

Please refer to Exhibit I-23-Staff-079 for information on the different scenarios.

The planning cycle horizon aligns with the period covered by the rate application from 2018-2022.

Building Owners and Managers Association Toronto Interrogatory # 131

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 2.3 Page: 9

Interrogatory:

Please provide a copy of the repair versus replace economic model.

Response:

Please refer to Attachment 1 of this response for Hydro One's refurbish/repair, replace economic model.

Asset Analytics
Asset Maintain – Refurbish / Repair – Replace Economic Evaluation Model

Revision History

Date	Model Version	Reason for Update	Author
August 17, 2012	v20120809	Make reference to Asset Analytics and general review and update	Michael Au
April 30, 2013	X	Added CCA adjustment, Upgraded Repair – Replace boundary curve	Michael Au / Shaoran Li

I. Introduction

The Asset Maintain –Refurbish / Repair – Replace economic model (R&R model) is developed by Asset Analytics. The purpose of this model is to facilitate asset "Maintain –Refurbish / Repair – Replace" decision making. The model is programmed in Microsoft EXCEL and is based on present value (PV) and net present value (NPV) analysis. In this model, the term "Major Investment" refers to either a "Refurbish" or a "Repair" investment. Cost of this investment is typically high.

The latest version of this model is [Filename: AA Repair-Replace Economic Evaluation Model version X].

For any question on the model and suggestions for further model improvement, please contact the Advanced Analytics and AM Process Improvement Department, Transmission Asset Management.

II. Present Value and Net Present Value Analysis

Net present value analysis is based on present values of future cash flows of competing options. In a NPV analysis, present values of future cash flows of competing options (using same discount rates) are summed over the same study period. The difference between the sums is the Net Present Value (NPV). The option with the lowest or highest NPV is the preferred option depending on the purpose of the study. In this asset Maintain –Refurbish / Repair – Replace model, is the lowest cost option is the preferred option.

A. Discount Rate

The discount rate is a key input in a NPV analysis. It is the rate at which future cash flows are discounted. In a NPV analysis, a "real" discount rate can be derived from two rate components – the inflation rate and the financial rate. The inflation rate is the rate on which future costs are escalated. The financial rate is the cost of capital (money). It is typically the weighted average cost of capital (WACC) for the corporation.

If i represents the financial rate and e represents the escalation (inflation) rate, the real discount rate, D, can be shown to be equal[1] to

$D = (i - e)/(1 + e)$, i.e.

Real Discount Rate = (Financial Rate - Inflation Rate) / (1 + Inflation Rate)

B. Cash Flows

Future cash flow is another key component in a NPV analysis. In an asset replacement decision, positive cash flows can represent cash outlay or investments. Negative cash flows can represent cash inflows, such as the disposal value received from sale of the existing asset. Another negative cash flow amount could be the realized residual value of assets at the end of a study period.

Relevant Cash Flows

Relevant cash flows are future cash flows that are directly associated with the investment options under consideration and over the same study period. These include:

- *Capital Cost* - Cost of acquiring and installing the new equipment.
- *Residual Value* - Value of an asset at the end of a study period.
- *Disposal Value* - The net revenue obtained from the disposal of an existing asset.
- *Operating and Maintenance Cost* - The annual cash flows that are required to maintain an asset. These cash flows include labour and material costs.

Irrelevant Cash Flows

Irrelevant costs are financial accounting charges which are non-cash charges. They do not involve an inflow or outflow of cash. Irrelevant cash flows include:

- *Depreciation* – It is an accounting method of allocating cost of an asset over its economic life.
- *Interest* – The appropriate allowance for interest charges is included in the discount rate.
- *Sunk Costs* - These are historical costs associated with past decisions.
- *Book Value* – Book value is the original capital investment minus the accumulated depreciation. This may not be an accurate representation of an asset's residual or disposal value.

Tax Savings on Capital Cost Allowance (CCA) [2]

The original version of the AA Repair-Replace Economic Evaluation Model did not include this component in the analysis. On Corporate Finance's suggestion, this later version of the model includes the tax savings on CCA in its cash flow calculations. The inclusion of CCA tax savings is a general lowering of cash flow requirement.

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[1] From $1 / (1+D) = (1+e) / (1+i)$

[2] Capital Cost Allowance (CCA) is the 'depreciation' method required by the tax regulations to report business income. CCA is a non-cash deduction from business income. As a result of the deduction, tax payable is reduced. This reduces the cash flow requirement of the business corporation as a whole.

Estimating Cash Flows
Amount and timing of future cash flows affect greatly the results of a NPV study. Asset managers typically use assumptions and judgement to make these estimates. The recommendation which follows from a net present value analysis will be no better than the estimates, assumptions and judgement used in the analysis. Therefore, asset manager must use extreme caution in selecting inputs to a NPV analysis.

General Guidelines
- Set cash flows to occur at the end of the year, even though some of the cash flows may occur throughout the year.
- Estimate the expected or most likely cash flows - not optimistic or pessimistic cash flows.
- Include all relevant cash flows. For example, for an asset "repair –replace" analysis, the repair cost should include the cost of the actual repair plus the cost of asset removal and re-installation. A replacement cost should include the cost of the equipment, engineering, other material, and installation. If there is any value received from the disposal of the existing asset, this amount should also be included. (In the attached economic model, disposal value is a separate entry).
- Estimate future asset maintenance costs from historical data. However, note that NPV analysis is concerned with future maintenance costs and not historical maintenance costs. Therefore, if the repaired equipment will be less reliable or if the new equipment will be more maintenance-free, the future costs should be estimated accordingly.

C. Study Period
There should be a common, long enough study period for the NPV model to perform its analysis. This period should cover at least a complete life cycle of the assets. In the existing model, the default study period is the higher of the replacing asset life and the existing asset remaining life.

III. The Asset Maintain – Refurbish / Repair – Replace Economic Evaluation Model

A. General Description

Basic Function
The attached economic model performs the following basic functions:
- Generate cash flow requirements of each investment option based on user inputs and/or assumptions over the same study period
- Calculate the present values of the cash flows
- Sum the present values of the options
- Compare the sums to determine the net present values and
- Decide on the preferred option

Basic Operation

- Start with the "Main Menu" screen. On this screen, enter the required inputs. (The required inputs are yellow colour-coded.)
- Select "Main Assumptions" to check assumptions. On the "Main Assumption Input" screen, press "Set to Default" to set assumptions to default values. Review and revise the assumptions as required. (Over-write green colour-coded cells if required. Values for the yellow-coloured cells come from the "Main Menu" screen and changes must be made in the "Main Menu" screen.)
- If "Generic Formula" maintenance cost representation is selected, select "Generic Formula Input" to review assumptions. On the "Generic Maintenance Cost Model Assumption Inputs" screen, press "Set to Default" to set the parameter values to the default values. Review the parameter values and revise values as required. (Over-write any of the blue-coloured cells.)
- If "User Input' maintenance cost representation is selected, select "User Input" to check and update required inputs. On the "User Maintenance Cost Inputs" screen, press "Reset" if necessary to reset input values and check for required inputs. Enter inputs as required.
- Move back to the "Main Menu" screen, select "Calculate"[3] to execute the program.
- Select "Summary Results" to view results.
- Select "Detail Results" to view details of the analysis.

B. Maintenance Cost

Maintenance cash flow is an important part of a NPV analysis. It is anticipated that maintenance cost information can come from 3 sources: a) SAP records, b) generic maintenance cost formula and c) direct inputs from investment planners.

a) SAP Records

Hydro One has collected asset maintenance costs in the SAP system since mid 2008. When sufficient data have been collected, it is possible to derive a maintenance cost function for the different asset types and classes on asset age. These cost functions can then be used in the economic model.

b) Generic Maintenance Cost Formula

Before specific asset maintenance cost curves can be derived for different asset types and classes, a "generic maintenance cost" formula is used in this R&R model to perform the NPV analysis. This "generic maintenance cost" formula is formulated using the following assumptions.

When an asset is new, there is an initial stable maintenance cost period. After this period, maintenance cost will begin to rise. The rise of maintenance cost is due to asset wear-out

[3] The function of the "Calculate" pushbutton is to calculate the break-even values of the investment options and to generate the "Repair-Replace Boundary" and the "Cash Flow" curves on the "Summary Results" screen.

and deterioration. After an asset refurbishment, the increasing maintenance cost will become stable again for a period of time before it starts to rise again. In some cases, refurbishment may also lead to a reduction of maintenance cost.

The generic maintenance cost formula[4] is formulated as:

Maintenance cost = [Initial maintenance cost] x $[1 + (t/td)^{2.5}]$, where

- t is the time from start of rising maintenance cost (start of asset deterioration),
- td is the time for the maintenance cost to double (doubling of deterioration).

Users are required to supply the following values for the generic maintenance cost formula:
- tu1, the time delay before a new asset's maintenance cost starts to rise
- td1, the time for the maintenance cost to double after it has started rising
- tu2, the 2nd maintenance cost stable period after a major investment
- td2, the time for the maintenance cost to double again after the major investment and after the stable maintenance cost period

c) Direct Inputs from Planners
Planners may have special requirement and knowledge, and may wish to provide the estimated maintenance costs directly.

Input Options for Maintenance Costs
The present version of the R&R model allows the users to choose either the "Generic formula" or the "User Input" maintenance cost options. The "SAP Input" option is not yet available.

The envisaged plan is to enable the "SAP Input" option when sufficient maintenance cost data have been collected and specific cost functions can be derived for the different asset types and classes. In the interim, if the user selects the "SAP" option, the model defaults the calculation to using the "Generic formula" method.

C. Main Menu Screen

The "Main Menu" allows the users to provide the minimum inputs to the model, initiate the analysis, and to review the results of the analysis.

Input Fields:

Type of Study, Asset Type, Class Type, Voltage Class: These are proposed future input fields. They are not active at this time. They are to be used when sufficient maintenance cost information has been collected in SAP. At the moment, maintenance cost is based on either the generic maintenance cost formula or user direct inputs, as described in Section B above.

[4] The asset wear out formula $1+(t/td)^{2.5}$ is adapted from Manitoba Hydro Repair /Replace Guide, 2002

Type of Study: “Maintain–Refurbish”, “Repair–Replace”, “Refurbish–Replace” etc.
Asset Type: Transformers, Breakers, etc.
Class Type: Oil, SF6, Air Blast (Breakers) etc.
Voltage Class: LV, 115 kV, 230 kV etc

Business Unit **–** This is the business unit to which the asset belongs. Different financial rates (weighted average cost of capital, WACC) are used by the different business units.

Replacement Asset Capital Cost, $k **–** Enter the installed cost of the replacing asset. This includes the engineering, equipment and installation costs.

Existing Asset Estimated Economic Life, years - Enter the estimated economic life of the existing asset.

Replacing Asset Estimated Economic Life, years - Enter the estimated economic life of the replacing asset.

Asset economic life information is used to calculate i) annual asset depreciation[5] and ii) maintenance costs under the “generic maintenance cost” default assumptions.

Depreciated asset value is an indication of asset disposal value, which is used in asset replacement and end of study terminal value adjustments.

Age of Existing Asset **–** Enter the age of the existing asset when the major investment (refurbish or repair project) is being considered.

Cost of Major Investment, $k **–** Enter the anticipated investment amount required to refurbish or repair the existing asset. This includes the removal, refurbish / repair, and reinstallation costs.

Observed Present Day Maintenance Cost **–** Enter the observed present day maintenance cost of the existing asset. This is not a mandatory input. The amount is not used directly in the NPV analysis. This input, if provided, is used to check the reasonableness of the tu and td parameter assumptions when the “generic maintenance cost formula” is selected for the NPV analysis.

Pushbuttons:

Main Assumptions
This will lead users to the Main Assumptions screen. Users can review the assumptions and revise them as necessary.

Calculate

[5] Straight line depreciation used in the model

This will calculate the "maintain–refurbish" and the "repair–replace" breakeven values based on the maintenance cost model selected, and generate the graphs shown on the Summary Results screen.

Summary Results
This will lead users to the "Summary Results" screen to view the results of the analysis.

Detail Results
This will lead users to the "Detail Results" screen to view the details of the cash flows.

D. Main Assumptions Screen

This screen contains the main assumptions used in the NPV analysis. Users can set the assumptions to the default values and then override these values if required.

Input fields:

Inflation / Escalation Rate (e), % - This is the assumed inflation rate for material and labour. The model uses this rate in conjunction with the financial rate to calculate the real discount rate. The real discount rate is then used to calculate the present values of future cash flows. The default is 2%, the same rate used by Corporate Finance.

Financial Cost Rate (i), % - This is the cost of capital (money) for the corporation. It is the weighted average capital cost (WACC) for the corporation. Corporate Finance provides this rate for different business units.

Corporate Tax rate (T), % - This is the corporate tax rate provided by Corporate Finance.

CCA Rate (d), % - The Income Tax Regulations sets out the Capital Cost Allowance (CCA) rate for different asset classes. Transmission and distribution assets belong to class 47. CCA rate for this class is 8%.

Repair - Replace Dead band, % - This is the percentage allowance from the theoretical "repair – replace" breakeven value. The graph in the Summary Results screen shows this dead band. The default is set at +/-10%.

Study Period, years – The model uses a default period of the greater of two values: 1) new asset economic life, and 2) updated remaining economic life of the old asset. Override the default value if required.

Existing Asset Disposal Value, $k - Enter the disposal value of the existing asset. Disposal value is used to reduce the capital cash flow requirement of the replacing asset. The default value is the straight-line depreciated book value of the existing asset. Override this value if required.

Life extension with major investment, years – If existing asset life is extended after a major investment (e.g. a refurbishment project), enter the life extension in years. The default is zero.

[Note: If the user enters a life extension, the user should consider the effect of this on study period requirement. The general guideline is study period should be long enough to cover one life cycle of the assets, i.e. remaining life of the existing asset or the life of the replacing asset. User can update the study period manually. Alternatively a second press of the ***Set to Default*** pushbutton will automatically calculate the required new study period. However, this action will also reset all other previously user-changed inputs on this screen to their default values. If the user has previously overwritten any other default values, the user has to re-enter these inputs.]

Maintenance Cost Representation – As indicated in Section B, maintenance cost can be represented in one of three ways. The present version of the model allows the users to choose either the "Generic Maintenance Cost Formula" or the "User Input" option to perform the analysis. If the "SAP" option is selected, the model defaults the calculation using the "Generic Maintenance Cost Formula" representation. The default is the "Generic Maintenance Cost Formula" selection.

Estimated maintenance cost reduction after major investment, % - If maintenance cost is expected to fall after a major investment (e.g. a refurbishment project), enter the estimated reduction. The default is zero %. This input is applicable to maintenance costs represented by cost formulae. If maintenance cost representation is "User-input", users will enter their estimated future costs directly.

Pushbuttons:

Main Menu
This will lead users back to the "Main Menu".

Summary Results
This will lead users to the "Summary Results" screen.

Detail Results
This will lead users to the "Detail Results" screen to view the detail analysis.

Set to Default
This will reset the inflation rate, financial cost rate, corporate tax rate, CCA rate, repair-replace dead band, study period, disposal value, life extension, maintenance cost representation, and maintenance cost reduction to the default values.

Generic Formula Input
This will lead users to the "Generic Maintenance Cost Model Assumption Inputs" screen to reset, update and review the assumptions used in the generic maintenance cost formula.

User Input
This will lead users to the "User Maintenance Cost Inputs" screen to review and enter the required user inputs.

E. Generic Maintenance Cost Model Assumption Inputs Screen

This screen shows the assumed inputs used in the Generic Maintenance Cost Formula. The basic "generic maintenance cost formula" is

Maintenance cost = [Initial maintenance cost] x $[1 + (t/td)^{2.5}]$, where

- t is the time from the start of asset deterioration, and
- td is the time for the deterioration to double.

Input Fields:

Initial asset maintenance cost in present day dollars, $k – It is the initial maintenance cost when the asset is installed new. The default is 1% of asset initial capital cost. Same amount is assumed for both the replacing and existing assets. Override these values if necessary.

Initial stable maintenance cost period, years, tu1 – This is the initial stable maintenance cost period after the asset is newly installed. The default is 30% of an asset's economic life (for both existing and replacing asset). For example, if the economic life = 50 years, tu1 = 15 years. Override these values if required.

Years for rising maintenance cost to double from onset of rising maintenance cost, years, td1 – This is the period for maintenance cost to double in the 1st wave of rising maintenance costs. The default is 50% of an asset's economic life (for both replacing and existing asset). For example, if asset economic life = 50 years, td1 = 25 years. Override these values if required.

2nd stable maintenance cost period after refurbishment / repair, years, tu2 – This is the maintenance cost stable period after a major investment (refurbishment / repair). The default value of tu2 = tu1 = 30% of an asset's economic life. Override this value if required.

Years for rising maintenance cost to double after maintenance cost starts to rise, years, td2 – This is the period for maintenance cost to double after a major investment (2nd wave rising maintenance cost). The default is td2 = td1 = 50% of an asset's economic life. Override this value if required.

Pushbuttons:

Main Menu
This will lead users back to the "Main Menu".

Main Assumptions
This will lead users to the Main Assumptions screen.

Summary Results
This will lead users to the "Summary Results" screen.

Detail Results
This will lead users to the "Detail Results" screen to view the detail analysis.

Set to Default
This will reset the parameters values - initial asset maintenance cost, tu1, td1, tu2, and td2 - to their default values.

Maintenance Cost Illustration based on Values of tu and td (in table and graph)
The increasing asset maintenance cost as a function of asset age is illustrated below the input fields and the pushbuttons - for different values of initial maintenance cost, tu1, td1, tu2, and td2 selected.

F. Summary Results Screen

The summary results screen shows the user inputs and the assumptions, and the main results of an asset (status quo) maintain – major investment (refurbish/repair) - replace NPV analysis. It also includes graphs that show the maintain – refurbish / repair – replace boundaries at different asset ages, and the expected cash flow requirements of the different investment options (status quo maintenance, refurbish / replace, and replace).

Information Fields:

The colours of the information fields match the colours of the input fields.

Real Discount Rate and Discount Factor – The real discount rate is calculated from the inflation / escalation rate and the capital cost discount rate. The discount factor is 1/ (real discount rate). If the real discount rate is inappropriate, adjust the *Inflation / Escalation Rate (e) and the Financial Cost Rate (i)* in the Main Assumption screen to provide the desired real discount rate.

Original Asset capital Cost benchmark – This is the replacement asset capital cost de-escalated to the year the original asset was installed.

Depreciated Book Value (of the Existing Asset) - This is a calculated amount based on straight-line depreciation of the original asset capital cost. If no user-input disposal value is specified (in the Main Assumptions screen), the depreciated book value is used to reduce the capital cash flow requirement of the replacing asset.

Modified Economic Asset Life - If a major investment results in an asset life extension, this is the revised asset life.

Expected Present Day Maintenance Cost – This is a value calculated based on the generic maintenance cost formula at the asset's given age. This value can be compared to the ***Observed Present Day Maintenance Cost*** below this value. If there is a significant difference between these two values, users should review and revise the tu1 and td1 assumptions (in the Generic Maintenance Cost Model Assumptions screen).

Revised present day maintenance cost - It is a calculated value based on the Expected Present Day Maintenance Cost and the estimated Maintenance Cost Reduction after Major Investment.

Summary Results:

Result Summary Table:
The results of the NPV analysis with and without CCA adjustments are shown below the information fields. Shown are:

- Present Values of the (Status Quo) Maintenance, the Major Investment (Refurbish / Repair) and the Replace options, for different inclusion of disposal value, terminal value, and CCA tax savings
- **Net** present values of the "Maintain – Major Investment" and "Major Investment – Replace" options with terminal value and CCA savings adjustments
- The preferred option based on the above NPV values
- The "Major Investment – Replace" breakeven value at the present asset age
- The upper and lower bounds of the breakeven value for the selected dead band

Refurbish - Repair – Replace Boundaries Graph:
The graph to the right of the information fields shows the Refurbish - Repair – Replace economic boundaries of the existing asset at different ages. This graph shows the boundaries for either the "Generic maintenance cost" or the "User-input" maintenance cost formulation.

Other Cash Flow Graphs:
The graphs below the Summary Results show the expected future cash flows under different investment options – Status quo maintenance, major investment (refurbish / repair) and replace.

G. Detail Results Screen

The Detail Results screen shows the cash flow requirements at different asset ages for different investment options, their present values, their sums, and other calculations that produce the final results of the NPV analysis.

IV. Illustration of the Model

The following examples illustrate the use of the model using the "Generic Maintenance Cost Formula" as the maintenance cost option. The asset is assumed to be a transmission low voltage breaker.

Rate Information (Main Assumptions):

Inflation / Escalation rate	2%
Financial cost rate	6.04%
Corporate Tax rate	26.5%
CCA rate	8%

Asset Information (Main Menu):

Age of Existing Asset	35 years
Estimated existing breaker economic life	50 years
Estimated replacing breaker economic life	50 years
Replacement asset capital cost	300k

A. Maintain – Refurbish Decision

Using default values,
Case a) If cost of refurbishment = \$25k (input from Main Menu)
    PV of maintain option = \$251.62k (Summary Results)
    PV of refurbishment option = \$247.52k (Summary Results)
    NPV of a Maintain – Refurbish decision = + \$4.10k (Summary Results)
Therefore the preferred option = "Refurbish", as PV of the Maintain option is greater than the PV of the Refurbish option (Summary Results).

Case b) If cost of refurbishment = \$30k
    PV of maintain option = \$251.62k
    PV of refurbishment option = \$252.52k
    NPV of a Maintain – Refurbish decision = - \$0.90k (Summary Results)
Therefore the preferred option = "Maintain", as PV of the Maintain option is less than the PV of the Refurbish option.

The breakeven investment that makes the NPV = 0 is \$29.10k.

Case c) If the refurbishment can result in an asset life extension of 3 years (input on Main Assumptions)
    If cost of refurbishment remains at \$30k
    PV of maintain option = \$245.79k
    PV of refurbishment option = \$236.98k
    NPV of a Maintain – Refurbish decision = + \$8.81k
Therefore the preferred option will change to "Refurbish", as PV of the Maintain option is greater than the PV of the Refurbish option.

Case d) If the refurbishment does not lead to an asset life extension, but can lead to a maintenance cost reduction of 3% after refurbishment (input on Main Assumptions)
    If cost of refurbishment remains at \$30k
    PV of maintain option = \$251.62k
    PV of refurbishment option = \$250.94k

NPV of a Maintain – Refurbish decision = + \$0.68k

Therefore the preferred option will also be to "Refurbish", as PV of the Maintain option is greater than the PV of the Refurbish option.

B. Refurbish – Replace Decision

For this illustration, the following are assumed:

- full depreciated book value (full disposal value) of existing asset is available to reduce the cash flow requirement of the replacing asset
- tu1 = tu2 = 0.3 of asset life = 15 years, and td1 = td2 = 0.5 of asset life = 25 years
- there is no life extension and maintenance cost reduction after a refurbishment

Case a) If cost of refurbishment = \$62k

PV of refurbishment option = \$284.52k

PV of replace option = \$290.34k

Therefore, the preferred option is the major investment (Refurbish) option as the PV of the replace option is more than the PV of the refurbish option.

Refer to case c) for discussion of the Investment Decision Preferred Option shown in the Result Summary table on the Summary Results screen.

Case b) If cost of refurbishment = \$73k

PV of refurbishment option = \$295.52k

PV of replace option = \$290.34k

Therefore, the preferred option is "Replace", as the PV of the refurbish option is greater than the PV of the replace option.

The breakeven investment amount for the above cases is \$67.81k. The above preferred options are for when there is no allowance made on the breakeven value.

Case c) If there is a decision dead band of 10% (input on Main Assumptions) applied

With a decision 10% decision dead band applied to the breakeven value of \$67.81, the upper bound and lower bound values are \$74.60k and \$61.03k respectively. Since both \$62k and \$73k fall within these boundaries, the indicated Investment Decision Preferred Option shown in the Result Summary table (Summary Results screen) is "Further Review".

Case d) If the refurbishment can result in an asset life extension of 3 years (input on Main Assumptions)

Without life extension after a refurbishment, and if the refurbishment cost is \$76k (greater than \$74.60k, the upper bound value), the preferred investment is "Replace". With the life extension of 3 years, the breakeven investment amount becomes \$82.88k. The upper and lower bound values become \$91.17k and \$74.60k respectively. Thus for this same amount of \$76k, the investment preferred option becomes "Further Review" when the 10% decision dead band is considered.

Under this scenario,
PV of refurbishment option, = \$282.98k
PV of replace option = \$290.34k

C. Repair – Replace Decision
An asset "repair – replace" analysis is very similar to an asset "refurbish – replace" analysis. Both involve a one-time major investment. The difference is in terms only - "Repair" rather than "Refurbish". In addition, because a (major) repair is probably due to a major asset failure, asset reliability may be worse after a repair. Values of tu2 and td2 may be different under these two scenarios. The following illustrations assume tu2 = ½ tu1 = 7.5 years, td2 = ½ td1 =12.5 years, and there is no life extension and maintenance cost reduction after the repair.

The breakeven value for the repair-replace decision is \$65.75 without the decision dead band. With a 10% dead band, the upper and lower bound values become \$72.32 and \$59.17k respectively.

Case a) If repair cost > \$72.32k (say \$74k)
The preferred economic option is to "Replace" as the required investment is more than the upper breakeven value.

Case b) If repair cost < \$59.17k
The preferred economic option is to "Repair" if a 10% decision dead band is applied.

Case c) If the disposal value of the existing asset is less than the depreciated book value of the asset
If the disposal value of the existing asset = \$0 (Main Assumption)
The breakeven boundary value of the repair – replace decision is \$110.75 k. The upper and lower bound values with the 10% decision dead band are \$121.82 and \$99.67k respectively.
For a repair cost of \$74k, the preferred option would have been to replace according to result of case a). With a disposal value of \$0, the preferred economic option becomes "Repair" as the repair cost is less than \$99.67k.
PV of the repair option = \$298.59k
PV of the replace option = \$335.34k

D. Maintain – Refurbish – Replace Decision
Without consideration of the decision dead band, section A indicates that it is not economical to refurbish an asset if the refurbishment cost is greater than \$29.10k. Section B indicates that "refurbish" is an economic option if the refurbishment cost is less than \$67.81k.

This may appear confusing. However, the confusion can be clarified as follows:

The maximum economic amount for an asset status quo Maintain – Refurbish decision is $29.1k. A refurbish investment over this amount indicates that the saving from expected future maintenance cost reduction is not sufficient to compensate for the initial investment.

Given a choice that an asset must be Refurbished or Replaced, the economic choice is to refurbish if the cost is less than $67.81k and to replace if it is more than this amount. If, however, a third choice of lower cost exists, this will be the economic choice.

The third choice could be the "status quo maintenance" or "do minimum" approach. Under this scenario, the asset will neither be refurbished nor replaced. The asset manager will only perform the necessary preventive and minor corrective maintenance on the asset to keep it operating. This is the typical scenario when an asset is approaching its end of life. At this stage, the asset manager should not refurbish the asset but to wait for its scheduled replacement.

As indicated in section C, the "refurbish – replace" and the "repair – replace" analyses are similar (both involve a major investment). The only difference is that under the repair scenario, the manger has no choice but to repair the asset if the asset is to remain in service. In the refurbish scenario, the asset manager has the choice to refurbish or not.

Note that repair is a maintenance activity (corrective maintenance). Therefore, with the assumed parameters and at age 35, without consideration of the decision dead band, the economic choices are

- Refurbish if the investment (refurbish) cost is less $29.1k
- Provide status quo maintenance if the investment (refurbishment cost) is above this amount – results from section A.
- Repair (corrective maintenance) - but not to refurbish or overhaul - if the investment cost is less than $67.81k, and
- Replace if the repair cost is greater than this amount – results from section B.

As a further illustration, assume a major investment requirement of $25k and use default assumption values. If the asset age is 35 years, the present values of the "status quo maintain - major investment – replace" options are $251.62k, $247.52k and $290.34k respectively. The most economic option is the "major investment" option. Therefore, for this investment amount, it is economic to either "refurbish" or "repair" the asset.

If the asset age is 45 years, the present values of the "status quo maintain – major investment – replace" options are $316.47k, $328.13k and $323.03k respectively. The most economic option is the "maintain" option. Therefore, for a Maintain – Refurbish decision, the "status quo maintain" option is a better choice.

If the major investment is necessitated by equipment breakdown, the do minimum - "status quo maintain" option is not available. The asset must be repaired or replaced for the asset to provide the required functions.

At asset age of 45, the preferred option is to replace ($323.03 replacement cost vs. 328.13k repair cost). At age of 35, the preferred option would have been "Repair" ($247.52k repair cost vs. $290.34k replacement cost) as shown earlier. At age 45, the major investment-replace breakeven point has moved to $19.9k (from $67.81k at age 35).

E. Refurbish – Maintain – Replace Boundary Graph

The "Refurbish - Repair – Replace Boundaries" graph in the Summary Results screen shows the economic "refurbish - repair – replace" boundaries of an asset at different asset ages.

The regions below and above the red marker boundary indicate the "Repair" and the "Replace" economic regions. If the major investment falls above the red line in, it is more economical to "replace" the asset. If the investment is below the red line, it is more economical to "repair". The two dotted boundaries above and below the red line indicate the decision dead band specified in the analysis.

The "grey" coloured line separates the "refurbish – maintain" economic regions. It is economic to refurbish if the required "refurbish investment' falls below this line. If the refurbish investment required falls above this line, it is better to just provide status quo maintenance on the asset and wait for the next scheduled replacement.

For the specified asset age under study, the graph shows the calculated economic "refurbish – maintain" and "repair – replace" values for the given inputs. For other ages, the graph uses reasonable assumptions on past and future asset costs and depreciated values to generate the boundary values. The graph provides an illustration of how economic values change with time and input values.

F. Cash Flow Graphs

The three graphs below the summary results in the Summary Results screen show the cash flow requirements of the three options: 1) status quo maintenance, 2) major investment (refurbish or repair), and 3) replacing the asset. Note that in all cases, the model assumes that the asset is replaced at its scheduled or revised scheduled end of life.

G. Asset Disposal Value

The recommended option derived from the economic model for a replace decision depends strongly on the disposal value of the existing asset. The impact is more profound during an asset's earlier years. In this economic model, disposal value of the existing asset is used to reduce the capital cash flow requirement of the replacing asset. Without an overriding input, the model assumes the disposal value is equal to the straight-line depreciated book value of the existing asset. At young ages, depreciated book value is high. Asset replacement cash flow requirement, therefore, could be quite low. As a result, the model will favour the replace option. If the disposal value is in fact low (e.g. if the asset has failed and the salvage value is below the depreciated book value), the recommended option could change to that of maintain (repair).

In the above example, using the default values, if the asset age is 10, the calculated depreciated book value (full disposal value) is $196.88k. The Repair – Replace threshold is $39.23k without the decision dead band. If the disposal value is only $30k, the Repair – Replace threshold will be raised to $236.11k.

H. Expected Maintenance Cost at Time of Major Investment

The recommended option derived from the economic model depends strongly on the values of the maintenance costs. When the generic maintenance cost formula is selected, these values depend on the initial maintenance cost, and values of tu1 and td1. If the observed maintenance costs do not agree with the calculated values, the user should recheck the values of the initial maintenance cost, tu1 and td1, and adjust these as necessary to generate a more representative maintenance cost series.

Hint: In the Summary Results screen, compare the “Expected present day maintenance cost” and the “Observed present day maintenance cost” values. In the “Generic Maintenance Cost Model Assumption Inputs” screen, make the adjustments.

I. Delay of Rising Maintenance Cost after a Major Investment

In this economic model, the same method is used to analyze the cash flow requirements of “Refurbish - Replace” and “Repair – Replace” scenarios.

It is expected after a refurbishment or a repair, maintenance cost will remain stable for a period of time before it starts rising again. The delay and the rate of rise of rising maintenance cost could be different for the refurbish and the repair scenarios. Users should choose the appropriate tu2 and td2 values for these scenarios.

As illustrated in sections B and C, if the 10% decision lower dead band is selected, and tu2 =tu1 and td2 = td1, the “refurbish / repair – replace” break-even amount is $61.03k. If tu2 = ½ tu1 and td2 = ½ of td1, the break-even amount at the 10% lower band will change to $59.17k.

V. Other Notes on the Model and Known Limitations

Tax Savings on CCA (Capital Cost Allowance)

The model calculates tax savings on CCA for up to one replacement cycle in the “status quo maintain” and “repair – replace” scenarios (asset is replaced at the existing asset’s end of life) and up to 2 replacements in the “replacing” scenario (one at the beginning of the study period and the second one at the end of life of the new asset).

Terminal Value

The existing model does not allow the user to specify a terminal value for the assets (residual asset value) at the end of the study period. Terminal value is considered in the

R&R model as a cash inflow to offset the total cash requirement for the study period. The existing model assumes terminal value = residual value = straight line depreciated value.

Asset Age and Study Period Mismatch

Existing model considers asset age begins from 1 (age 1 = the first period after an asset is put into service, age at end of life = n = asset life). For study period = default selection, existing model cash flows for n+1 periods (with end of study adjustments). The effect of this mismatch is minor and the next model upgrade will correct this discrepancy.

Building Owners and Managers Association Toronto Interrogatory # 140

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 2.3
Section 2.3.2

Interrogatory:
a) Please define service lines and provide examples.

b) Does this approach apply to all service lines to institutional, industrial customers, or just residential customers?

c) Why are the service lines to larger customers not maintained?

d) What percentage of outages are due to service line failures?

Response:
a) Please refer to page 12 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.2.2.2 for details on the service lines.

b) Yes, this applies to all service lines owned by Hydro One.

c) Service lines to large customers are often owned by and the responsibility of the customer. Service lines owned by Hydro One are run on a break-fix basis.

d) As Hydro One does not own all secondary service lines, the outages due to these service line failures are not tracked.

Building Owners and Managers Association Toronto Interrogatory # 152

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

A-03-01-04 Page: 11 Exhibit A, Tab 3, Schedule 1, Attachment 4, Bullet 7

Interrogatory:

Has a similar analysis been performed for distribution reliability performance versus maintenance program spend? If so, please provide. If not, why not?

Response:

No, however Hydro One Distribution did undertake an assessment of past maintenance expenditures and activities, with a focus on critical factors and contributors to the distribution reliability measure.

Energy Probe Research Foundation Interrogatory # 35

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.1 Page: 17 Table 4
B1-01-01 Section 1.5 Page: 2-3 Table 17

Interrogatory:

Are the savings listed in Table 4 cumulative or incremental?

Response:

Please refer to Exhibit I-10-EnergyProbe-008.

Witness: LOPEZ Chris

Energy Probe Research Foundation Interrogatory # 36

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 2.1 Page: 27 Table 34

Interrogatory:

Preamble: Energy Probe is curious on how Hydro One came up with these weightings.

a) Please explain Hydro One's methodology for these weightings.

b) Please provide any documents, memos or studies related to how Hydro One established these weightings.

Response:

a) The weightings were originally established based on a comparison of prioritization criteria with senior management and adjusted to reflect business priorities as appropriate.

   For example, Hydro One management re-assessed the weightings in 2015 to reflect Hydro One's desire to improve the outcome-based factor of "Customer Satisfaction." This resulted in the weighting assigned to the business driver "Customer Focus" being increased to 20%. There was also a reduction in weighting given to reliability from 20% to 15%.

   In 2016, the weightings were reviewed with the CEO and CFO, with a recommendation to not change the weightings. The recommendation was accepted and these are the weightings used for this application.

b) There is no available workshop documentation to establish the original weightings. See Attachment 1 which contains the recommendation not to change the weightings.

Witness: JESUS Bruno

Objectives & Weightings

May 27, 2016

Agenda

Decision Required: Investment Management is recommending **no change** to the current objectives and weightings used for optimisation.

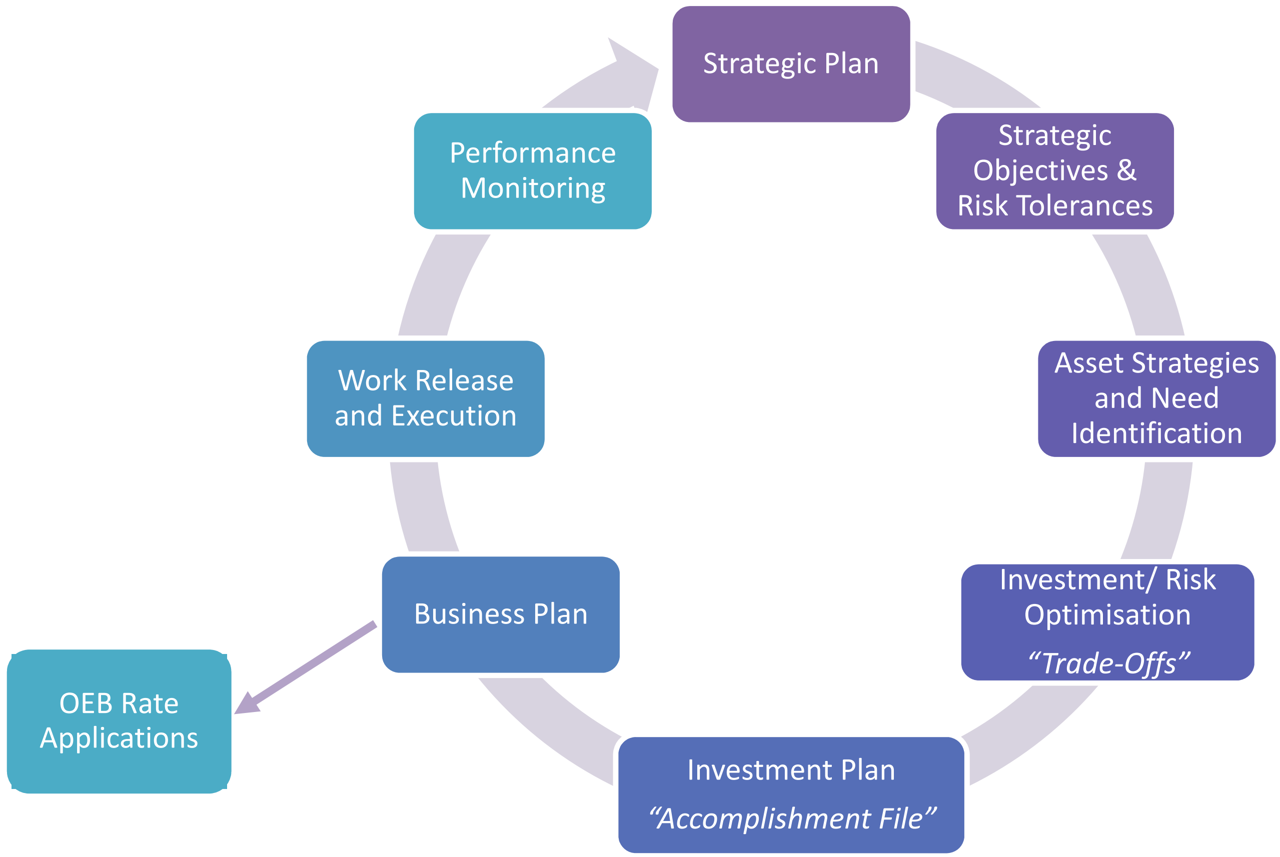
The Corporate Strategy is a cascading framework throughout the organization and sets the overall direction for Investment Planning.

Our Strategic Plan builds on the company's strong commitment to the Province of Ontario and is shaped by our Values. It lays out a set of clear objectives to position Hydro One to achieve its Mission and Vision.

In planning and executing our work, everything we do supports our Mission, Vision and Strategic Objectives

The "*Strategic Objectives*" are the *Corporate Risk Tolerances* and the objectives are implemented as the basis for the ***risk-based optimisation*** of the Investment Plan.

The Investment Planning Process takes direction from the Strategic Plan and Strategic Objectives.



The Strategic Objectives are the basis for decision making and are aligned with the principles of the RRFE.

Customer Risk
- Large and Mid Customers
- OEB Service Quality
- Residential & Small Business

Reliability Risk
- Tx Reliability – acute events
- Tx Reliability – system performance
- Dx Reliability – annual outages

Shareholder Value Risk
- Net Income
- Credit Worthiness
- Shareholder Confidence
- Public Profile/Reputation
- Regulatory Compliance
- Regulatory Approvals
- Licence Conditions and Regulatory Credibility

RRFE Principle	Strategic Objectives
Customer Focus	**Customer**
Operational Effectiveness	**Safety**
	Reliability
	Productivity
	Employees
Public Policy Responsiveness	**Environment**
Financial Performance	**Shareholder Value**

This enables a consistent assessment of all investments based on risk-value and how they contribute to the achievement of the organisations goals.

Safety Risk
- Employee/Contractor Health & Safety
- Public Safety

Productivity Risk
- Unit Costs
- Work Program Accomplishment

Employee Risk
- Employee skills and engagement

Environment Risk
- Environmental Performance

Recommendation: No change to the current strategic objectives and weightings used for optimisation.

The strategic objectives are mapped from the corporate risk tolerances.

Note: individual weightings are determined through the allocation of 115 total value points

At this time, no change to the objectives or weightings is recommended for use in optimising the investment plan.

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Energy Probe Research Foundation Interrogatory # 37

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 2.3 Page: 75

Interrogatory:

a) Since 2010, how many buildings has Hydro One deemed surplus?

b) What was the value of those sales by year

Response:

a) As of 2010, Hydro One had three surplus buildings.

b) The properties deemed surplus were sold as follows:

1. Former Matheson Area Office
   Sold September 2012
   $40,000.00

2. Former Bracebridge Area Office
   Sold May 2015
   $510,000.00

3. Former Nipigon MEU Office
   Sold October 2015
   $19,000.00

Energy Probe Research Foundation Interrogatory # 38

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 2.1 Page: 30

Interrogatory:

Please provide any variance proposals for projects with a budget of more than $1 million.

Response:

Table 1 lists variances for projects with budgets greater than $1 million reflected in Hydro One's last distribution application (EB-2013-0416).

Table 1: Variance Proposals for Material Projects

Year	ISD	Investment Name	Variance Type			Variance
			Cost	Schedule	Scope	
2015	SA05	Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm	☐			**Cost:** $729K
	SS-02	Beckwith DS T2 and F3			☒	**Scope of Work Changes**
	SR-06	Purchasing and Installation of Pilot IMDS's	☒	☒		**Cost:** $3,700K **Schedule:** +776 days
2016	SS-02	Commerce Way New Feeder Extension	☒			**Cost:** $617K
	SR-13	Bob-Lo DS Voltage Conversion	☒			**Cost:** $932K
	SR-13	Belle River DS Voltage Conversion	☒	☒		**Cost:** $1,031K **Schedule:** +730days
	SS-02	Nebo TS M12 Extension to Hamilton Airport	☒	☒		**Cost:** $1,534K **Schedule:** +192days
2017	SS-02	Nobleton DS T1 – new 27.6kV transformer and feeder	☒	☒	☒	**Cost:** $1,100K **Schedule:** +213days **Scope of Work Changes**

Witness: JESUS Bruno

Energy Probe Research Foundation Interrogatory # 39

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.6 Page: 5

Interrogatory:

a) Given Hydro One's numerous references to its aging fleet of poles, why did the company underspend in that category in both 2015 and 2016? Please provide a detailed response.

b) Is Hydro One on track to meet its pole replacement budget in 2017? Please explain any variance.

Response:

a) Hydro One underspent the pole replacement program by 3% in 2015 and 2016 due to lower than planned unit costs. However, the pole replacement program was 1% over accomplished in terms of the number of poles replaced.

b) Part of the pole replacement budget in 2017 was redirected to higher priority projects. For 2015 to 2017, 91% of the planned pole replacement volumes have been completed.

Energy Probe Research Foundation Interrogatory # 40

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.6 Page: 7

Interrogatory:

Please breakdown the $23 million by spending category. For example, how much was spent on the Web Redesign?

Response:

The breakdown for the $23 million increase in 2017 investments for customer centric Information Technology investments is as follows:

- CTI Replacement $6M
- Web Redesign $3M
- eBilling and Customer Usage Analytics $3M
- Bill Redesign $5M
- Demand to Interval Migration $6M

Witness: MERALI Imran

Energy Probe Research Foundation Interrogatory # 41

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-02-01 Page: 3

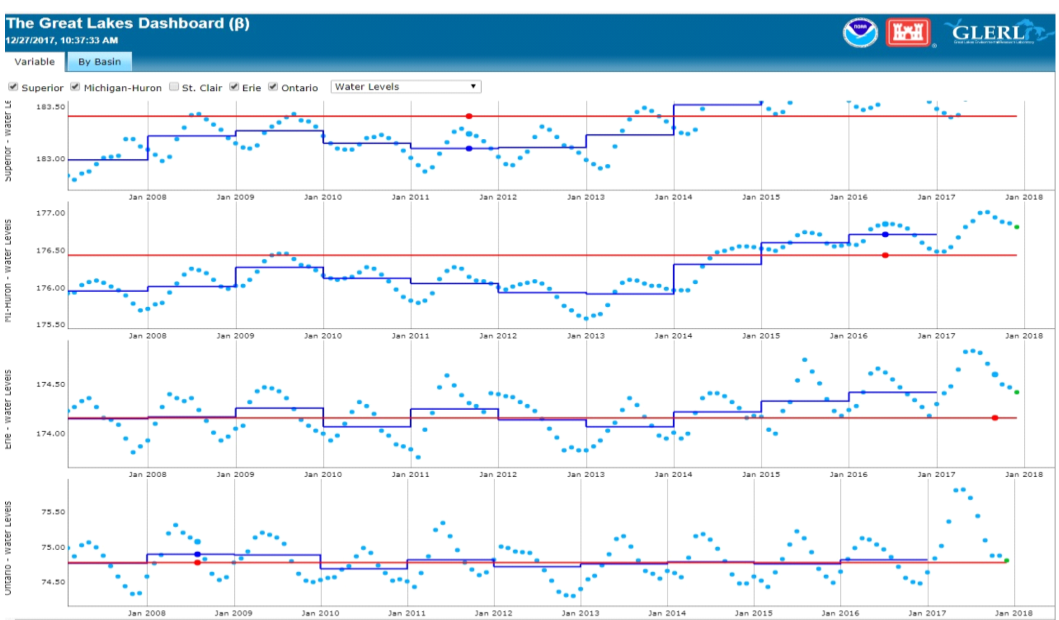
Interrogatory:

Preamble: Hydro One states that it is increasing its submarine cable maintenance programs to "meet challenges as a result of receding water levels in the Great Lakes…"

Data from the NOAA Great Lakes Environmental Research Laboratory suggest that water levels have increased in recent years.

Can Hydro One provide evidence that water levels in the Great Lakes are continuing to recede and what the direct cost of receding water levels is to the utility?

See data here:
https://www.glerl.noaa.gov//data/dashboard/GLD_HTML5.html



Witness: GARZOUZI Lyla

Response:

Hydro One did not intend to comment on the overall trend of water levels in the Great Lakes or any other bodies of water. Seasonal variations in water levels do occur, and can temporarily expose cables that were previously submerged. The volumes of submarine cable replacements and refurbishments are driven by the need to eliminate hazards associated with deteriorated cables as these are found.

Energy Probe Research Foundation Interrogatory # 42

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.4 Page: 3 Table 8

Interrogatory:

Are the cost metrics in Table 8 adjusted for inflation? Please explain why or why not.

Response:

Yes. The targets are based on the investment plan, which is adjusted for inflation.

Energy Probe Research Foundation Interrogatory # 43

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.4 Page: 7

Interrogatory:

As Hydro One has indicated a number of metrics are sensitive to changes in the scope of work. Please explain how Hydro One will prevent reduction in the scope of work over time to maintain consistent reporting of actual metrics.

Response:

The Quality Control and Quality Assurance program outlined in Exhibit Q, Tab 1, Schedule 1, page 14 is in place to ensure that work planning and execution adhere to the established standards and that the work program fully achieves the scope of work.

Energy Probe Research Foundation Interrogatory # 44

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 1.4 Page: 13

Interrogatory:
Hydro One proposes to cease reporting metrics on the number of replaced poles and the number of pole top transformers with PCB Oil. Will Hydro One still track these numbers for other purposes and, if required, make them available to the OEB in the future?

Response:
Yes, Hydro One will continue to track these numbers and make available if required.

Energy Probe Research Foundation Interrogatory # 45

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.4-A01 Page: 1

Interrogatory:

How will Hydro One ensure that there is no confusion between savings and avoided costs?

Response:

Please refer to Exhibit I-25-Staff-123.

Energy Probe Research Foundation Interrogatory # 46

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.4-A01 Page: 3

Interrogatory:

Hydro One indicates that each line of business is accountable for developing a productivity strategy including targets and forecasts for the business planning period. Have these productivity strategies been developed? If they have, please file them. If not please explain why not and indicate when the productivity strategies are expected to be completed.

Response:

The Productivity Strategy referenced on p.5 of the 'Productivity Reporting Governance Document' is an internal term used in the context of describing the accountability of the business units to evaluate their business, identify initiatives, target set, and execute on the productivity commitments which have been embedded in Hydro One's business plan. The output of this process is not a formal document, but a list of initiatives which make up Hydro One's productivity plan. The detailed productivity plan is provided in Exhibit I-25-Staff-123.

Energy Probe Research Foundation Interrogatory # 47

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 8

Interrogatory:

The list of changes that Supply Chain has made such as Bundling/Volume Discounts are long standing established practices in industry. Why is Hydro One only now implementing these changes?

Response:

Supply Chain was performing some Bundling and was requesting Volume Discounts from suppliers prior to the IPO; however, a renewed approach was introduced following the IPO. The renewed approach looks to maximize savings opportunities in each of these areas through better sourcing categorization and consolidation of contracts with single suppliers.

Energy Probe Research Foundation Interrogatory # 48

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 12

Interrogatory:

Hydro One states that "to date, 138 servers and 38 databases have been decommissioned, with plans to decommission an additional 67 servers and three databases by early 2017. This has reduced Hydro One's monthly server and database fees."

a) Were these assets owned or leased by Hydro One?

b) If they were owned what was the net book value of the decommissioned assets?

c) What were the costs of decommissioning and what account were they charged to?

d) What was the reduction in Hydro One's monthly server and database fees?

Response:

a) Hydro One owned these assets.

b) Net book value for servers and databases are tracked at an asset category level. Server assets termed decommissioned in Exhibit B1-01-01 Section 1.5 page 12 are not necessarily written off or physically removed. The asset may still be available for repurposing, but presently Hydro One has ceased maintenance support.

c) Decommissioning costs are funded through Base IT Sustainment Services presented in Exhibit C1-1-9 table 3, to support Hydro One IT applications and infrastructure that is outsourced to Inergi LP ("Inergi").

d) For 2016, the reduction in Hydro One's monthly server and database fees, attributed to Hydro One Distribution only, was approximately $0.039M/Month.

Energy Probe Research Foundation Interrogatory # 49

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 21

Interrogatory:

Please confirm that a reduction in IT capitalization threshold will reduce OM&A expense and increase rate base and depreciation expense. If that is the case, please provide an estimate of this proposal on revenue requirement.

Response:

Please refer to Exhibit I-10-Staff-49.

Energy Probe Research Foundation Interrogatory # 50

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.2 Page: 1 Table 54

Interrogatory:

a) Were there any changes in categories of capital expenditures between 2013 and 2017?

b) Why is System OM&A shown in a table of capital expenditures?

c) Please explain the reasons for the large variances shown in the System Service category for 2015, 2016 and 2017.

d) Please explain the reason for the large variance shown in the General Plant Category for 2017.

Response:

a) The categories of expenditures remain consistent between 2013 and 2017.

b) System O&M is shown in the table of capital expenditures as per OEB DSP Chapter 5 Filing Requirements pages 18-21.

c) Please refer to Exhibit I-29-Staff-165 part (b).

d) Please refer to Exhibit I-29-Staff-165 part (c).

Energy Probe Research Foundation Interrogatory # 51

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8

Interrogatory:

Please file approved business cases for the following programs. If approved business cases do not exist, please file documents that were used in obtaining senior management approvals for these programs.

a) SA-01 Joint Use and Line Relocations Program

b) SA-02 Metering Infrastructure Sustainment Program

c) SA-03 Meter Infrastructure Expansion Program

d) SA-04 New Load Connections, Upgrades, Cancellations and Metering

e) SA-05 Distributed Generation Connections

f) SR-06 Distribution Station Refurbishment

g) SR-07 Distribution Lines Trouble Call and Storm Damage Response Program

h) SR-13 Life Cycle Optimization & Operational Efficiency Projects

i) SR-14 Advanced Meter Infrastructure Hardware Refresh

j) SS-02 System Upgrades Driven by Load Growth

k) SS-05 Distribution System Modifications

l) GP-01 Transport & Work Equipment

m) GP-02 Real Estate Field Facilities Capital

n) GP-18 Integrated System Operating Centre

Response:

Hydro One's process is to initiate and approve business cases for project work. Program work is approved with the Business Plan by the Board of Directors.

a) SA-01 Joint Use and Line Relocations Program: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

b) SA-02 Metering Infrastructure Sustainment Program: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

c) SA-03 Meter Infrastructure Expansion Program: The majority of investments that are part of this ISD are program work and, therefore, do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials. The project covered by this ISD has not been released into execution and does not have a business case yet.

d) SA-04 New Load Connections, Upgrades, Cancellations and Metering: The investments that are part of this ISD are program work only and, therefore, do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

e) SA-05 Distributed Generation Connections: The majority of investments that are part of this ISD are program work and, therefore, do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials. The project covered by this ISD has not been released into execution and does not have a business case yet.

f) SR-06 Distribution Station Refurbishment: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

g) SR-07 Distribution Lines Trouble Call and Storm Damage Response Program: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

h) SR-13 Life Cycle Optimization & Operational Efficiency Projects: See Attachments 1 and 2 for the business cases for material projects covered by this ISD. (The Manitou Lake DS project was inadvertently omitted from the list in the ISD, but not the ISD cost forecast.) Not all projects have business cases yet, as they are not ready for release into execution.

i) SR-14 Advanced Meter Infrastructure Hardware Refresh: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

j) SS-02 System Upgrades Driven by Load Growth: See Attachments 3 to 7 for the business cases for material projects covered by this ISD. Not all projects have business cases yet, as they are not ready for release into execution. A few of the attached business cases only cover parts of the identified projects, which are being released in phases. (The Allanburg project was inadvertently omitted from the list in the ISD, but not the ISD cost forecast.)

k) SS-05 Distribution System Modifications: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

l) GP-01 Transport & Work Equipment: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

m) GP-02 Real Estate Field Facilities Capital: The investments that are part of this ISD are program work only and therefore do not have a business case. See Exhibit I-3-SEC-4 for Board of Directors materials.

n) GP-18 Integrated System Operating Centre. The construction-phase business case is still being finalized and will be provided once it is signed off.

Filed: 2018-02-12
EB-2017-0049
Exhibit I-25-EnergyProbe-51
Attachment 1
1 of 4

Manitou Lake Distribution Station an Line Work

Overview of Recommended Alternative:

Approval of $4,650k is requested to build a new 44-12.5kV Manitou Lake Distribution Station to supply West Bay DS feeders and to remove West Bay DS. A prior approval was obtained for $200k to produce the estimate, bringing the total project approval to $4,850k.

Investment Details:

In-service: October 31, 2017

West Bay DS is located on private property and the owner of the land has indicated that they do not wish to renew the current lease arrangement with Hydro One, which ends in June 2018. Additionally, the station has been in-service since 1953, and is beyond average expected life of 50 years. The structures are in unacceptable condition and need to be remediated. The station site is highly congested and surrounded by other commercial operations. Therefore, it is proposed that a new Manitou Lake DS be built in a new location and West Bay DS be removed.

The scope of work includes building a new 44-12.5kV distribution station with a single transformer and three 12.5 kV feeders and the removal of West Bay DS. The 44kV circuit and a 12.5kV circuit will be extended from West Bay DS to the new station location by adding to the existing 12.5kV line for 1.3 km. The land for the station has been purchased.

Not proceeding with this work presents risks to customers, reliability and the shareholder. If West Bay DS is not removed from private property after lease end, there is potential for litigation given Hydro One would be violating the lease agreement. In addition, given the condition of the structures and the age of the station, there is a possibility of station assets failing that could result in long outages due to the difficulty of a Mobile Unit Substation installation in the congested site.

This investment is the recommended alternative based on technical studies showing that it is the most effective solution to meet the needs of West Bay area while maintaining reliability. It will also allow the transfer of load from Little Current DS F2 feeder to the Manitou Lake DS feeder, which would otherwise exceed the planning guidelines for feeder loading.

Benefits:

The completion of this work will meet the need to vacate the station from private land in accordance with lease requirements. It will maintain reliability of supply to the West Bay area and allow Little Current DS F2 feeder loading to remain within planning guidelines for the next ten years, by transferring some of its load to the new Manitou Lake DS feeders.

Estimated Costs & In-service:

The entire project will be in-serviced at project completion.

The cost breakdown is as follows:

Category	Cost ($k)
Project Management	202
Engineering	363
Procurement	606
Construction	2504
Commissioning	81
Estimating (actual cost to date)	179
Contingency	303
Interest & Overhead	612
Total	4,850

This investment has an approved budget of $530k in 2016 and is included in the draft 2017-2022 business plan to be approved by the Board in November with total funding of $3,802k. The additional funding required in 2017 and 2018 will be managed through reprioritization of other initiatives within the Distribution investment driver.

The estimate is release quality with contingency of $303k, which is equivalent to 8% of the project base cost, to cover any deviation from the original design during execution.

Other Alternatives Considered

Status Quo or Do nothing Alternative
Status quo is not a viable alternative as it does not address the need to vacate private land after the lease expires and does not address the condition of station assets at West Bay DS.

Alternative Two
This alternative consists of building a new feeder from Mindemoya DS by adding a 12.5kV circuit to the existing 12.5kV line for 13.3 km to pick up the West Bay DS feeders. This alternative was rejected as it would reduce reliability by increasing feeder length and would not allow transfer of load from Little Current DS feeder.

Regulatory Considerations

In 2017, $4.8 million of capital expenditures for a new Manitou Lake distribution station and new feeder development at that DS are included in the Ontario Energy Board approved 2015-2017 Distribution Rate Filing [EB-2013-0416].

Risks and Mitigation

The estimate did not include a geotechnical study to determine location and depth of bedrock. If bedrock is encountered, it may impact the cost of construction and station grounding. In the event the risk materializes, it is expected the impact could be up to $100k, which can be covered by the estimate contingency cost.

This Approval ($): 4,650k	Previous Approval ($): 200k	Total Approval ($): 4,850k
Signature Block:		
Approved by: Peter Faltaous	**Title:** Manager, Distribution Investment Planning	**Date:** August 18, 2016
Approved by: Wade Frost	**Title:** Manager, Decision Support	**Date:** Aug 18/16
Approved by: Paul Brown	**Title:** Director, Distribution Asset Management	**Date:** Aug 18/16

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($k)	2017($k)	2018($k)	Total ($k)
Capital* and MFA	309	4,126	0	4,435
OM&A and Removals	0	15	400	415
Gross Investment Cost*	309	4,141	400	4,850
Recoverable	0	0	0	0
Net Investment Cost	309	4,141	400	4,850

*Includes capitalized interest and overhead at current rates

Rate base additions

	2016($k)	2017($k)	2018($k)	Total ($k)
In-Service $ Additions	-	4,435	0	4,435

In-service Date:	October 31, 2017
Business Case Summary #:	51000508
Appropriation Request #:	23063
Subject ID #	80939
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Paul Brown
Planner	Gert Alikaj

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

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

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

Dresden DS Conversion

Overview of Recommended Alternative:

Approval for $2,800K is requested to proceed with removing Dresden DS and converting existing 8.32kV customers to 27.6kV. This total includes $205K, approved in January, 2017 to prepare a detailed estimate.

Investment Details:

In-service: Nov 30th, 2019

Dresden DS located in Chatham-Kent, is amongst the worst transformers in the province from a condition perspective, and is at risk of failure, due to moisture leaking into the station transformer. Due to the loading of the Dresden DS 8.32kV feeders, and relative proximity of customers to existing 27.6kV lines, Asset Management has determined that conversion in lieu of refurbishment is the most cost effective option. Furthermore, converting to 27.6kV will make the supply adequate for upcoming load growth in the area.

The Distribution system modifications will be undertaken in two dependent phases, so as to reduce the impact of outages on customers:

- Phase 1 involves new overhead distribution line construction of 3km, to convert existing 8.32kV customers to 27.6kV.
- Phase 2 involves additional overhead line construction of 1.5km, to convert the remaining customers on Dresden DS to 27.6kV, and removal of Dresden DS.

The total cost for both phases is currently expected to be approximately $2,800K. Not proceeding with this investment will mean that customers continue to be exposed to a poor performing Dresden DS, and a distribution system that would not be adequate for future growth.

Benefits:

This investment provides an opportunity to remove an end of life asset, and increase system capacity, while minimizing the outage impact to our customers.

Estimated Costs & In-service:

The in-service date of the entire project is November 2019, with Phase 1 assets projected to be placed in-service by June 2018. The cost breakdown is as follows:

Category	Cost
Previous Approvals	$205K
Construction of 4.5km overhead Dx line and conversion costs	$1,460K
Contingency	$146K
Interest/Overhead	$355K
Removals	$634K
Total	$2,800K

Phase 1 construction costs are $1,300K of the total cost and are based on an estimate with an accuracy of +/- 10%. The remainder of the total cost is for Phase 2 construction, which is based on a planners estimate with an accuracy of +/- 50%. Detailed estimate for Phase 2 is expected to be completed by Nov 2018. This project construction Phase 1 will need to begin in early 2018, prior to completion of the Phase 2 component of the estimate, because the necessary resources are available.

This investment is included in the approved 2017-2022 investment plan and the draft 2018-2023 investment plan with total funding of $2,900k, including $300k in 2018 and $2,600k in 2019. Any capital expenditure variances will be managed within the Distribution Capital Driver envelope through redirection of funds from other projects.

Other Alternatives Considered

Status Quo or Do nothing Alternative

The status quo option was rejected, as the transformer is end of life, and at risk of failure.

Alternative 2 – Refurbishment of Dresden DS

Alternative 2 was not considered further; as it has a similar capital cost ($2.5-$3.0M), with additional maintenance costs for station inspections and equipment repairs of $30k/year, and it does not address future system capacity needs.

Regulatory Considerations

This investment is included in Hydro One's Distribution rate application (2018-2022) currently before the Ontario Energy Board for approval, with in-service additions totaling $2.6M in 2019. This BCS is projecting the cost to be in line with that forecast in the rate filing, however with some in-service timing differences. Any variances will be managed through the Redirection Process.

Hydro One considers the risk of non-recovery of these expenditures to be low because this investment will increase the quality of Hydro One's distribution system, meet our obligations to customers under the Distribution System Code and eliminate operational risks associated with operating end-of-life assets.

Risks and Mitigation

Soil Contamination – The cost of the 2nd phase of the construction is based on a planners estimate (+/- 50%). The environmental assessment for station removal costs has not been completed at this time. If the detailed estimate discovers major environmental work in the Dresden DS area, the cost could increase by $140K.

This Approval ($): $2,595k	**Previous Approval ($): $205K**	**Total Approval ($): $2,800k**
Signature Block:		
Approved by: Ted Lyberogiannis	**Title:** Manager, Dx Investment Planning	**Date:** Nov 10 '17
Approved by: Wade Frost	**Title:** Manager, Decision Support	**Date:** Nov 10/17
Approved by: Lyla Garzouzi	**Title:** Director, Dx Asset Management	**Date:** Nov 10, 2017

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($k)	2017($k)	2018($k)	2019($k)	Total ($k)
Capital* and MFA	5	242	919	1,000	2,166
OM&A and Removals	-	5	127	502	634
Gross Investment Cost*	5	247	1,046	1,502	2,800
Recoverable	-	-	-	-	-
Net Investment Cost	5	242	919	1,000	2,166

*Includes capitalized interest and overhead at current rates

Rate base additions

	2018($k)	2019($k)	Total($k)
In-Service $ Additions (BCS)	1,016	1,150	2,166
In-Service $ Additions – Rate filing (Dx 2018-2022)	255	2,297	2,552
Variance	761	(1,147)	(386)
Redirection/Available	Redirection	Available	Available for Phase 2

In-service Date:	Nov 30th, 2019
Business Case Summary #:	51002347
Appropriation Request #:	24444
Subject ID #	81235
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Lyla Garzouzi
Planner	Usman Shaheen

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

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

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

Leamington TS Feeder Construction - Phase 2 Approval

Filed: 2018-02-12
EB-2017-0049
Exhibit I-25-EnergyProbe-51
Attachment 3
1 of 4

Overview of Recommended Alternative:

Approval for $33.7M is requested to complete Leamington transformer station distribution line construction, thus enabling completion of the Supply to Essex County Transmission Reinforcement project. This total includes $13.6M, approved in 2016 to prepare detailed distribution line estimates, and to order materials and complete construction for phase 1 of the distribution line work.

Investment Details:

In-service: June 30, 2019

Hydro One's Board of Directors approved the Supply to Essex County Transmission Reinforcement project on May 6, 2016, which comprises the construction of Leamington Transformer Station, and a 13km 230kV transmission line. When the Board of Directors approved the Transmission business case, it was disclosed that there was a need for a separate project, to build new and modify existing distribution assets, to complete the transmission project.

Approval for the distribution system modifications will be undertaken in two dependent phases:

- Phase 1 ($13.6M) was approved in 2016 to relocate a distribution line to make way for the new transmission line and station, and some additional feeder work near the station.
- Approval is sought for Phase 2 ($20.1M), which involves installation of additional distribution poles to accommodate 8 new distribution lines from Leamington Transformer Station. Approximately 30km of distribution poles, and 50km of conductor will be installed during phase 2, which enables the removal of 2 regulating stations, and partial conversion of a distribution station.

The $33.7M cost of completing the Leamington transformer station distribution work is substantially higher than the originally anticipated $19.3M, primarily due to the unforeseen need to enhance the system with larger distribution poles to enable the expected 300MW of new load. Furthermore, the new distribution line lengths and routes have been revised since the 2014 plan, based upon completion of the investment planner's area study. The variance was further compounded by an estimating error related to the application of overhead, interest and contingency in the original estimate.

Separate approval will be sought in the future for additional transmission and distribution investments to facilitate future anticipated customer demands.

Benefits:

This investment will complete required distribution work for the Supply to Essex County Transmission Reinforcement project, and provides the following additional benefits:

- Enabling the connection of customers, with requested incremental load of 200MW
- Enhancing the distribution system to simplify the future connection of incremental load of 100MW

- Removal of two regulating stations which will no longer be required in the reconfigured distribution system, and partial conversion of two distribution stations which would have otherwise required refurbishment in the next 10 years, which will reduce future maintenance costs

Estimated Costs & In-service:

This is a multi-year project, with partial in-service additions throughout the project lifecycle.

The cost breakdown is as follows:

Category	Cost ($M)
Previous Approvals	$13.6 M
Construction of new overhead distribution lines	$8.4 M
Smart tie switches for DMS integration and DG relocation costs	$0.7 M
Construction of Duct Bank for 12 feeder egresses	$1.7 M
Phase 2 Contingency	$2.6 M
Phase 2 Interest/Overhead	$3.6 M
Phase 2 Removals	$3.1 M
Total Expenditure	$33.7 M

Construction costs are based on estimates from Provincial Lines and Engineering Services, with an accuracy of +/- 15%.

This investment is included in the 2017-2022 Business Plan, with total gross funding of $18.3M, and net funding of $10.5M. Additional funding required in 2017 will be met through deferred spending on other distribution projects. The additional budget and in-service additions outside of the current year will be included in the 2018-2022 business plan to be developed later this year.

Other Alternatives Considered

Status Quo or Do nothing Alternative
The status quo option was not considered further, as it would impact the ability of Hydro One to complete the Ontario Energy Board approved Supply to Essex County Transmission Reinforcement project, and to simplify connection of 300MW of load to the distribution system.

Regulatory Considerations

During the S.92 Leave to Construction hearing for the Supply to Essex Country Transmission Reinforcement project, the Ontario Energy Board was advised of the scope and need for this type of distribution work at a forecast cost of $19.3M.

Hydro One's next distribution rate application for years 2018 to 2022 has been filed with the Ontario Energy Board in 2017. Approval of this investment will result in an in-service additions variance of $18.3M compared to the filed rate application, and may raise the interest of the Ontario Energy Board and interveners which Hydro One may be required to defend during the hearing.

Hydro One has proposed as part of the Supply to Essex County Transmission Reinforcement Project section 92 to the Ontario Energy Board that a modified distribution cost allocation methodology will be applied. This cost allocation methodology will be finalized by the Ontario Energy Board's generic Cost Allocation hearing to decide which customers' ultimately bear the costs of the new line. Using the proposed methodology, it is forecasted that $0.3M in capital contributions will be recovered from embedded distributors.

Overall, Hydro One considers the risk of non-recovery of these expenditures to be low because this investment is required to accommodate the construction of the Supply to Essex Country Transmission Reinforcement project given S.92 approval from the Ontario Energy Board.

In-service additions approved in this Business Case may be deferred as a result of an ongoing initiative to balance in-service additions with respect to our approved Dx rates.

Risks and Mitigation

No major risks are anticipated relating to this approval.

This Approval ($): $20.1M	**Previous Approval ($):** $13.6M	**Total Approval ($):** $33.7M
Signature Block:		
Approved by: Darlene Bradley	**Title:** VP, Planning	**Date:** May 24, 2017
Approved by: Chris Lopez	**Title:** SVP, Finance	**Date:** May 24, 2017
Approved by: Gregory Kiraly	**Title:** Chief Operating Officer	**Date:** 5/24/17
Approved by: Mayo Schmidt	**Title:** President & Chief Executive Officer	**Date:** 5/26/17

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
Capital* and MFA	7.0	13.3	8.4	0.8	29.5
OM&A and Removals	0.7	2.0	1.3	0.2	4.2
Gross Investment Cost*	7.7	15.3	9.7	1.0	33.7
Recoverable		0.2	0.1		0.3
Net Investment Cost	7.7	15.1	9.6	1.0	33.4

*Includes capitalized interest and overhead at current rates

Rate base additions

	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
In-Service $ Additions from estimate	-	-	25.8	3.4	29.2
In-Service $ Additions included in Business Plan	-	-	-	10.5	10.5
Variance	-	-	25.8	(7.1)	18.7

In-service Date:	June 30, 2019
Business Case Summary #:	51001418
Appropriation Request #:	23304
Subject ID #	81080
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Lyla Garzouzi
Planner	Alexander Hamlyn

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

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

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

hydro one

Investment Driver: N.D.C.2.02
AR Number: 23061

Date: February 05, 2016
Investment Name: Kirkland Lake TS – Archer Drive Voltage Conversion

Hydro One Networks – Business Case Summary – Claim No. 51000034
Kirkland Lake TS – Archer Drive Voltage Conversion

In Service: October 31, 2017

This Approval: $1001k **Previous Approval:** $3k **Project Total:** $1004k

Overview of Recommended Alternative:

The Town of Kirkland Lake area study completed in 2013 recommended converting the town to 12.5 kV as the most economical option to improve reliability, and address capacity needs and end-of-life assets in the area. This project is one of the stages in voltage conversion of the Town of Kirkland Lake. It will extend a feeder from Swanson DS along Archer Drive to Woods DS and move 44kV section from off-road to Archer Drive. The system enhancement requires approval of $1,001K investment. This investment will address capacity needs, improve power quality and reduce outage time.

Investment Details:

The town of Kirkland Lake is an urban area of approximately 3000 customers, that is fed by three 44/4.16 kV distribution stations (Goodfish DS, Woods DS and Kirkland Lake DS) and is experiencing strong economic growth. The current load of 12 MVA is projected to increase to 14.6 MVA by 2018, with a growth rate of 1% thereafter. The 4.16 kV system has limited capacity to accommodate the load growth. Additionally, field personnel have also reported that the switchgear at Goodfish DS has in one instance not tripped for short circuit, posing safety concerns. These are metal-clad switchgear, which are no longer being supported by manufacturers.

The proposed alternative will address the above mentioned issues by converting the town from 4.16 kV to 12.5 kV. The first stage of the conversion work was done in 2015. The scope of this investment will cover the second stage, which includes extending Swanson DS 12.5 kV F2 feeder along Archer Drive to Woods DS, moving the 44 kV G3K line from off-road, and overbuilding on F2 feeder along Archer Drive. This alternative will make the higher voltage available in the Town's Industrial Park and will bring 12.5 kV up to the main part of the Town to facilitate the conversion work in the future years.

Not proceeding with this investment will result in increasing system reliability and safety risks associated with limited supply capacity and outdated equipment.

Benefits:

- Proceeding with this alternative will remove capacity constraints through 12.5 kV feeders which have higher capacity than 4.16 kV feeders.
- Power quality will be improved through 12.5 kV feeder, which has lower system impedance than 4.16 kV resulting in less voltage fluctuations.
- Relocating 44kV section on road will reduce outage time during maintenance and emergency response.

Estimated Costs & In-service:

Yearly Expenditures

	2016 ($k)	2017 ($k)	Total ($k)
Capital* and MFA	100	781	881
OM&A and Removals	0	120	120
Gross Investment Cost*	100	901	1001
Recoverable	0	0	0

Author: Gert Alikaj
Date: February 05, 2016

Net Investment Cost	100	901	1001
In-Service $ Additions	0	881	881

*Includes overhead and capitalized interest at current rates

The cost breakdown is as follows:

Category	Cost ($k)
Estimate incl. removals	779
Contingency	78
Interest & Overhead	144
Total	1001

The cost is based on a class C estimate with accuracy of +/-50%.

Investments funded by DC202 driver (System Capability Reinforcement (2016 - $103M)) provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This project is included in the approved 2016 Budget under AIP005377 for $100K. The remainder is included in the 2017-2022 Business Plan to be approved in May 2016 with total planned gross funding of $901k. Any additional funds, if required will be re-prioritized within the investment driver.

Other Alternatives Considered

Status Quo or Do nothing Alternative
Doing nothing does not address customer, shareholder and reliability risks associated with limited capacity to supply load and end-of-life assets. As such, this alternative was rejected.

Regulatory Considerations

$0.5 million of Distribution capital expenditures for 2016 for the Kirkland Lake TS – Archer Drive Voltage Conversion project are included in the OEB approved 2015-2017 [EB-2013-0416] Distribution rate filing application under the Development category, within the line "Development projects/programs less than $1M". The additional funding requirements will be managed within the Distribution Capital driver envelope through reprioritization of work, or identification of delayed projects. No other significant regulatory issues are anticipated other than standard need and prudence justification.

Major Project Risks and Mitigation

All risks are forecasted to be low.

hydro one

Investment Driver: N.D.C.2.02

AR Number: 23061

Date: February 05, 2016

Investment Name: Kirkland Lake TS – Archer Drive Voltage Conversion

Funds Included in Business Plan: Yes	Director: Paul Brown	Planner: Gert Alikaj
This Approval ($): $1001k	Previous Approval ($): $3k	Current est. of Total Cost ($): $1004k

Signature Block:

Approved by:	Title:	Date:
Wade Frost	Manager, Decision Support	May 10/16
Peter Faltaous	Manager, Distribution Investment Planning	May 11, 2016

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

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

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

hydro one

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

Investment Name: Dundalk Victoria DS F2: 1-3phase conversion		Claim #: 51001447
AR: 24483	Investment Driver: D.C.2.0.2	In-service Date: Nov 1, 2017
This Approval: $195k	Previous Approval: $0k	Total Approval: $195k

Investment Summary:

This request is for $195k, to reconstruct a portion of Dundalk Victoria DS F2 feeder, in preparation for subdivision growth. The approval amount of $195k is based on a DETL estimate, which was requested through Distribution Planning, and therefore was not charged against this AR.

Dundalk is a town within the municipality of Southgate, Ontario, and is supplied electrically at 4.16kV from Dundalk Victoria DS. Within the last year, Hydro One has received significant proposals for residential subdivisions in the town. As a result of a system impact assessment, it has been determined that the new subdivisions at the northern edge of the town cannot be supplied from the existing 1ph (2.4kV) feeder.

To ensure Hydro One can continue to connect residential subdivisions on the northern edge of Dundalk, this investment will rebuild an existing section of 1ph line, such that it is capable of being energized at 3ph. It is desirable to rebuild this line section in advance of 3ph availability, since the affected section of road is already under construction as part of the subject residential development. Therefore, in order to minimize the impact that construction will have to existing Hydro One customers on Doyle St, it will be rebuilt with pole height and framing for 3ph supply.

Other Alternatives Considered

Status Quo: The do-nothing approach is not viable since upcoming subdivisions have been identified as requiring 3ph supply.

Alternative 1: Reconstruct the existing Hydro One assets along Doyle St, such that they are framed for 3ph (upgraded from existing 1ph). Since Doyle St is already under construction, and creating a disturbance for existing Hydro One customers along this street, completing the work now will prevent a second disruption in the near future to upgrade the line from 1ph to 3ph.

Benefits

This investment will ensure Hydro One is able to connect a new residential subdivision, and maintain its customer commitments.

Cost			
(in $K)	2016	2017	Total
Capital & MFA		195	195
OM&A and removals			
Gross Investment Cost		195	195
Recoverable			
Net Investment Cost		195	195

Note: Not for use for projects $1 Million or greater. Include all previous approvals

Project Risk Assessment

This project is in the 2017-2022 Accomplishment File, with sufficient funding (AIP005916).

The project is intended to be constructed in 2017, to meet customer commitments. Zone 2 Planning has confirmed the availability of resources to complete the work.

Signature Block

Prepared & Recommended by: Mark van Tol	Title, Department: Dx Investment Planner	Signature:	Date: June 30, 2017
Approved by: Ted Lyberogiannis	Title, Department: Manager, Dx Investment	Signature:	Date: June 30 ,17

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

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

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

Author: Mark van Tol
Date: June 30, 2017

hydro one

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

Investment Name: Bradford DS F3 - Reinforcement		Claim #: 51001165
AR:24484	Investment Driver: D.C.2.0.2	In-service Date: Nov 1, 2017
This Approval: $406k	Previous Approval: $0k	Total Approval: $406k

Investment Summary:

This request is for $406k, to construct a new pole line along 10 Sideroad, between 6th Line and 5th Line.

The Township of Bradford West Gwillimbury is in the process of constructing a new arterial roadway to the east of Hwy 400, between 5th Line and 6th Line. This arterial roadway is associated with the introduction of new commercial and industrial developments which will flank Hwy 400 between 5th Line and 9th Line. At present, there is insufficient capacity at Bradford DS to support the anticipated growth.

The newly constructed pole line will be designed with sufficient height for two (2) 27.6kV circuits, and one (1) 44kV circuit. One of the feeder positions will be used to maintain the existing 8.32kV circuit from Bradford DS F3. The remaining 27.6kV circuit position will be used for an eventual tie point between the 27.6kV feeders from Doane DS F2 and Holland DS F1, which will be required to support planned growth for the area west of Bradford. Inclusion of pole height for 44kV overbuild is also anticipated to be required for future commercial / industrial loads on the lands abutting Hwy 400.

Other Alternatives Considered

Status Quo: The do-nothing approach is not a viable option since Hydro One will be limited in its ability to connect new customers.

Alternative 1: Construct a new pole line along 10 Sideroad, between 6th Line and 5th Line. The new pole line will be framed for double-circuit 27.6kV, with sufficient pole height for 44kV overbuild.

Benefits

This investment will ensure Hydro One is positioned to support growth in the Bradford area, by reinforcing the Bradford DS F3 feeder. This will maintain Hydro One's ability to connect new customers, and will prepare the pole line for the introduction of 27.6kV to the area.

Cost

(in $K)	2016	2017	Total
Capital & MFA	-	$357k	$357k
OM&A and removals	-	$49k	$49k
Gross Investment Cost	-	$0k	$0k
Recoverable	-	$0k	$0k
Net Investment Cost	-	$406k	$406k

Note: Not for use for projects $1 Million or greater. Include all previous approvals

Project Risk Assessment

This project is in the 2017-2022 Accomplishment File, with sufficient funding (AIP005917).

Multiple significant projects are pending for the Newmarket area. Staff resourcing could therefore be an issue, dependent upon project / customer timing.

Signature Block

Prepared & Recommended by: Mark van Tol	Title, Department: Dx Investment Planner	Signature:	Date: Jan 10 2017.
Approved by: Ted Lyberogiannis	Title, Department: Manager, Dx Investment	Signature:	Date: Jan 10/17

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

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

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

Author: Mark van Tol
Date: Jan 2, 2017

Filed: 2018-02-12
EB-2017-0049
Exhibit I-25-EnergyProbe-51
Attachment 7
1 of 4

Allanburg TS M5 feeder construction

Overview of Recommended Alternative:

Requesting approval of $4,773k for the installation of a new M5 feeder from Allanburg TS, decommission the Thorold Port Robinson DS, construct approximately 8km of distribution line, and remove approximately 4km of conductors. This full approval includes the previous approval of $150k as part of the estimating phase.

Investment Details:

In-service: December 1, 2018

The city of Thorold is supplied by the Allanburg TS M6, M7 and M8 feeders. The M6 and M7 feeders are forecasted to be loaded above the Planned Loading Limit by 2017 due to large customer connections. Allanburg TS feeders in the subject area are all radial supplies with limited back up capabilities.

Thorold Port Robinson DS is in very poor condition. The three single phase transformers are 65 years old, which are 15 years over their expected service life. The fuses currently installed are non-standard with no spares. The bushings are leaking and becoming difficult to support the conductors. In addition the station has 1MVA of load with no significant load growth expected.

To resolve the overloading issue on Allanburg TS M6 & M7, the reliability issue with radial feeder supplies, and the end-of-life equipment at Thorold Port Robinson DS, it is proposed to build a new 27.6 kV M5 feeder from Allanburg TS and construct approximately 8 km of feeder through voltage conversions. The new M5 feeder will create loops in the subject area increasing reliability to 555 customers that are currently being supplied from radial feeders. The project will also convert Thorold Port Robinson DS feeder from 4.16 kV to 27.6 kV and eliminate the DS.

Benefits:

This investment will provide the following benefits:

- The new M5 feeder will provide additional 17 MVA capacity for future load growth in the area, which will increase customer satisfaction by accommodating new customer connections above the existing feeder capacity.
- The new feeder provides improvement to reliability in the area by creating redundancy to 555 customers in the area. Whenever there is an upstream outage, these customers can be transferred to another feeder to reduce the SAIDI. This will reduce the risk of having long customer interruptions from radial feeder supplies.
- The voltage conversion to Thorold Port Robinson DS will eliminate an end-of-life station reducing the risk of equipment failures that lead to customer interruptions.

Estimated Costs & In-service:

All capital assets will be in-serviced in 2018 at project completion.

The cost breakdown is as follows:

Category	Cost ($k)
Previous approval for Class A estimate	150
Material	632
Labour	1,340
Transport and work equipment	502
Contractor/Sundry/Easement Costs	248
Removals	797
Contingency	366
Interest & Overhead	738
Total	4,773

The previous approval of $150k was to carry out detailed engineering and estimating. The necessary estimate has been completed to achieve an estimate accuracy of +/-10%.

This investment is included in the 2017-2022 Business Plan with total funding of $3,678k. The additional $1,095k will impact the project cash flow for 2018 however it can be managed within the Distribution Capital Driver through redirection of funds from other delayed projects.

Other Alternatives Considered

Status Quo or Do nothing Alternative

The existing 27.6 kV supply capacity is not adequate for the load growth in the area over the next five years. The Thorold Port Robinson DS is also at end-of-life requiring major sustainment work. This alternative is, therefore, rejected as it does not address the customer risk associated with capacity constraint and reliability risk associated with end-of-life assets.

Alternative 1 – Build new Allanburg TS M5 and Refurbish Thorold Port Robinson DS

This alternative requires building a new M5 feeder from Allanburg TS and refurbish Thorold Port Robinson DS. This is not a preferred alternative because the overall cost of the project is approximately $1.5M higher than the recommended alternative.

Regulatory Considerations

The project is not included in the 2015-17 Ontario Energy Board approved distribution rate filing [EB-2013-0416]. Hydro One has filed a 2018-22 distribution rate filing that includes total Project expenditures of $3,678k and additions to rate base of $3,246k, forecast to be placed in-service in 2018. The in-service asset forecast used in this BCS will result in an in-service capital additions variance of $730k higher than the amounts included in the 2018/22 distribution rate filing.

Hydro One considers the risk of non-recovery of these expenditures to be low because this investment is expected to increase system reliability in the area and accommodate future expected load growth.

Risks and Mitigation

No major risks are anticipated relating to this approval.

This Approval ($): $4,623k	Previous Approval ($): $150k	Total Approval ($): $4.773k
Signature Block:		
Approved by: Ted Lyberogiannis	Title: Manager – Distribution Asset Management	Date: April 5 17
Approved by: Wade Frost	Title: Manager – Decision Support	Date: April 9/17
Approved by: Lyla Garzouzi	Title: Director - Distribution Asset Management	Date: April 5, 2017

Appendix: Required information for SAP data input

Yearly Expenditures

	Pre-2017($k)	2017($k)	2018($k)	Total ($k)
Capital* and MFA	150	2,239	1,587	3,976
OM&A and Removals			797	797
Gross Investment Cost*	150	2,239	2,384	4,773
Recoverable		0	0	0
Net Investment Cost	150	2,239	2,384	4,773

*Includes capitalized interest and overhead at current rates

Rate base additions

	Pre-2017($k)	2017($k)	2018($k)	Total ($k)
In-Service $ Additions	-	-	3,976	3,976

In-service Date:	December 1, 2018
Business Case Summary #:	51001465
Appropriation Request #:	23233
Subject ID #	80521
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Lyla Garzouzi
Planner	Helen Guo

Scientific Research & Experimental Development Tax Credits (SR&ED
Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

Ontario Sustainable Energy Association Interrogatory # 18

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 1.6 Page: 23
Preamble: "Attachment – Name

1. Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile
2. Vegetation Management Program – CN Utility Inc.
3. IT Budget Assessment Study – Gartner Consulting"

Interrogatory:
a) What was the cost of each of the Benchmarking Studies?

Response:
a) Hydro One will not be providing the cost of the studies as the fees are considered not relevant to the research contained in the studies and confidential under the OEB's Practice Direction on Confidential Filings, Appendix A, (a), i.

School Energy Coalition Interrogatory # 48

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.4-A01

Interrogatory:

With Respect to the Productivity Reporting Governance Document:

a) The document is dated February 17th 2017. What is the status of the implementation of the deliverables (p.4) and the Productivity strategy each line of business is required to develop (p.3)?

b) For the purposes of this document, what is meant by "Lines of Business"?

c) Are the Productivity strategies that each line of business (p.3) is required to develop part of the 2018-2022 budgets that underlies this application?

d) For each material line of business, please provide a copy of their Productivity strategy (p.3).

Response:

a) With respect to productivity strategy in Exhibit B1, Tab 1, Schedule 1, Attachment 1, Productivity Reporting Governance Document, p.5, the detailed productivity plan is provided in Exhibit I-25-Staff-123. With respect to the deliverables shown in the table on p.6, please refer to Exhibit I-18-Staff-067, part a).

b) Lines of Business are organizational working groups, examples include: Operations, Customer Care, Technology and CIO, etc.

c) The productivity initiatives that have been embedded into the business plan underlying this application.

d) The detailed productivity plan is discussed in Exhibit I-25-Staff-123.

Witness: KIRALY Gregory, BRADLEY Darlene

School Energy Coalition Interrogatory # 49

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 2

Interrogatory:

For each initiative set out in Table 17, please provide a detailed explanation of the derivation of the productivity savings forecast.

Response:

Please refer to Exhibit I-25-Staff-123 for the updated productivity list and associated details.

Witness: LOPEZ Chris

OEB Staff Interrogatory # 122

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.1 Page: 29

Distribution System Plan Overview, Section 1.1.1 (5.2.1 A) KEY ELEMENTS OF THE DSP, pg 29 of 2930; **and**

DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.3.1 POLE REPLACEMENT PROGRAM STUDY, pg 1992 of 2930.

"The pole replacement program (ISD SR-09) is planned to be lower in 2018, to address customer rate sensitivities. The program will then increase until 2020 and level off in 2021 and 2022. There is a low reliability impact associated with this plan. Hydro One's goal is to sustain or modestly improve the condition of the pole fleet through the investment planning period."

"Recommendation 4: Pole Refurbishment Program

The study found that most of the peer group perform pole refurbishment. The study recommended refurbishing poles where possible. Hydro One will investigate the feasibility and cost benefit analysis of this option and its impact on work methods. The results of this analysis will determine if Hydro One will implement a pole refurbishment program."

Interrogatory:

a) It was recommended that Hydro One consider implementing a pole refurbishment program. Please provide details and the current status of this recommendation.

b) Could implementing a pole refurbishment program potentially take some pressure off the capital cost of pole replacements?

Response:

a) Hydro One is investigating different types of wood pole refurbishments. The two types being considered are structural refurbishment and chemical refurbishment. Structural refurbishment involves attaching a steel member or wood pole stub to an existing pole in order to reinforce it. Chemical refurbishment involves applying a retreatment product to the pole during a drill test to restore the pole's chemical treatment at the ground line.

Chemical refurbishment is the currently preferred alternative. When combined with a drill testing program, this type of refurbishment has a low incremental cost. Preliminary discussions with vendors have occurred, and Hydro One is determining optimal cycle length, optimal candidates for refurbishment, and application licencing.

b) Chemical refurbishments have the potential to extend the life of the wood pole population which, in the long term, has the potential of reducing the annual capital investment in wood pole replacements. However, chemical refurbishments must be applied before any rot has started to develop within the pole otherwise it can be ineffective.

OEB Staff Interrogatory # 123

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 1966-1967
(5.2.3) Productivity and Continuous Improvement, Section 1.5.1 Productivity Savings in the Plan, Table 17 – Detailed Productivity Savings Forecast

Table 17 – Detailed Productivity Savings Forecast

$Millions	2018	2019	2020	2021	2022
Move to Mobile	10.3	10.5	10.7	10.7	10.7
Procurement	14.2	15.3	19.1	20.2	20.8
Telematics	1.0	1.0	2.4	2.8	3.1
Total Capital	**25.5**	**26.8**	**32.2**	**33.7**	**34.5**
Move to Mobile	2.7	2.8	2.9	2.9	2.9
Operations	20.0	23.1	24.1	25.4	28.0
Procurement	2.2	2.1	2.5	2.7	2.8
Customer Service	1.8	2.6	3.2	4.1	4.8
Telematics	0.8	0.8	1.4	1.3	2.2
Information Technology	7.3	9.3	9.3	9.3	9.3
Total OMA	**34.8**	**40.7**	**43.4**	**45.8**	**50.0**
Procurement	1.8	1.8	1.8	1.8	1.8
Administrative	1.4	1.5	1.5	1.5	1.5
Total Corporate Common	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**
Total Savings	**63.5**	**70.8**	**78.9**	**82.8**	**87.8**

Interrogatory:

a) Please provide the detailed calculations used to derive the projected productivity savings identified in Table 17 above.

b) Please describe how Hydro One will track these savings.

c) What assurances do ratepayers have that Hydro One will achieve these forecast savings?

Response:

a) The updated evidence filed on December 21, 2017 includes an update to Hydro One's productivity savings forecast that has been embedded into the business plan. A more detailed view of the savings initiatives and the associated assumptions used are included in the table below.

				Updated Savings				
	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	2018	2019	2020	2021	2022
Capital	Move to Mobile	Move to Mobile (Field Force)	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Pole Replacement, Field Meter Service, Component Replacement*	$ 10.3	$ 10.5	$ 10.7	$ 10.7	$ 10.7
Capital	Procurement	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 12.7	$ 13.2	$ 17.0	$ 16.7	$ 18.6
Capital	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*	$ -	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Capital	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Capital	Telematics	Telematics	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 13.4	$ 10.1	$ 9.8	$ 9.6	$ 9.3
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 1.8	$ 2.6	$ 3.2	$ 4.1	$ 4.8
OM&A	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 7.4	$ 8.3	$ 11.5	$ 11.5	$ 11.5
OM&A	Information Technology	Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.9	$ 1.0	$ 0.9	$ 0.9	$ 0.9
OM&A	Information Technology	Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7
OM&A	Move to Mobile	Move to Mobile (Clerical)	FTE Reduction *Reflects expected reduction in 29 back office support staff by 2020*	$ 2.7	$ 2.8	$ 2.9	$ 2.9	$ 2.9
OM&A	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 7.6	$ 7.8	$ 7.9	$ 8.1	$ 8.2
OM&A	Operations	Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8
OM&A	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls*	$ 2.8	$ 4.1	$ 5.9	$ 6.9	$ 7.9
OM&A	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.3	$ 0.4	$ 0.4	$ 0.4	$ 0.4
OM&A	Operations	Engineering Work Team Migration	FTE Reduction *A reduction in support staff that was utilizing the legacy software*	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
OM&A	Operations	Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5
OM&A	Procurement	Procurement	IT Software Cost Reduction *Reflects expected and negotiated savings*	$ 0.9	$ 1.7	$ 2.6	$ 2.6	$ 2.6
OM&A	Telematics	Telematics	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ 0.8	$ 0.8	$ 1.4	$ 1.3	$ 2.2
CCC	Administrative	Corporate Common Head Count Reductions	FTE Reduction *Identified headcount reductions by position in Corporate Common*	$ 1.7	$ 1.9	$ 1.9	$ 1.9	$ 1.9
CCC	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 2.3	$ 2.3	$ 2.3	$ 2.3	$ 2.3

Total	Capital	$ 36.4	$ 34.2	$ 37.8	$ 37.3	$ 39.0
Total	OM&A	$ 29.4	$ 33.7	$ 40.9	$ 42.9	$ 45.5
Total	Corporate Common	$ 4.0	$ 4.2	$ 4.2	$ 4.2	$ 4.2

b) Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.

All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.

Finance reviews all productivity reporting to ensure each initiative meets the following criteria:

- Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
- Auditable with an applicable baseline for reporting;
- In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.

c) Ratepayers are assured through Hydro One's commitment to achieving the forecast savings targets. This commitment is demonstrated by:

i. The enhanced governance and visibility in Hydro One's productivity reporting process;
ii. Incremental productivity savings being identified in the updated evidence filed on December 21st, 2017;
iii. Embedding the forecast savings into the business plan which puts the achievement risk on Hydro One's Net Income and not on the ratepayer;
iv. Including the savings and associated net income targets on the Team scorecard for management staff; and
v. Ratepayers are protected through the Custom Incentive Rate mechanism which allows for increases in OM&A, limited to inflation less productivity. If Hydro One fails to achieve its productivity savings it will not impact customer rates.

OEB Staff Interrogatory # 124

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 1985

(5.2.3) Benchmarking, Section 1.6.2.3 Vegetation Management Program Study

"Recommendation #1:
Bring the whole distribution system to a four to eight-year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule."

Interrogatory:

a) Why does Hydro One use such a broad range of brushing cycles? Please explain in detail.

b) Please identify the areas within Hydro One's service area to which the different cycle ranges are applicable, including the reasons driving the use of shorter cycle lengths in the applicable areas.

Response:

a) Under Hydro One's new vegetation management strategy outlined in Exhibit Q, Tab 1, Schedule 1, vegetation management cycles have been shortened and standardized to three years across the Province.

b) As described in part (a) the vegetation management cycle in all areas within Hydro One's service area have been standardized to three years. The reasons driving the use of this shorter cycle length is outlined in Section 2.1 of Exhibit Q, Tab 1, Schedule 1.

OEB Staff Interrogatory # 125

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 1994

(5.2.3) Benchmarking, Section 1.6.3.2: DISTRIBUTION STATION REFURBISHMENT PROGRAM STUDY

"Recommendation 4: Station Refurbishment Approach and Rate

The study found that Hydro One's power transformer age profile ranks in the older end of the peer group distribution. The study also found that Hydro One's "Expected Service Life" for power transformers is somewhat higher than the peer group average."

Interrogatory:

a) Please provide details of the methodology Hydro One uses to calculate "Expected Service Life" for power transformers and for other major asset classes.

b) Does Hydro One understand why its "Expected Service Life" for power transformers is somewhat higher than the peer group average? If yes, please explain why.

c) Does Hydro One adjust the expected service lives of different asset classes based upon the results of its asset condition assessment process, on its retirement records, a combination of these, or some other factors?

d) How often does Hydro One update its "Expected Service Life" calculations?

Response:

a) "Expected Service Lives" for power transformers and other major asset classes are calculated based on asset depreciation rates. The depreciation rates which Hydro One uses were developed through depreciation reviews performed by Foster Associates Inc., an external independent depreciation advisor. Please refer to Exhibit C1, Tab 6, Schedule 1, Attachment 1, for the most recent asset depreciation study performed.

b) Some factors which may cause variability between the "Expected Service Life" of an asset from one utility to another include:
   - Equipment loading;
   - Equipment specifications such as overload capability;
   - System operation such as protection settings, and fuse coordination to minimize the impact of system faults damaging equipment; and/or
   - Equipment maintenance practices.

c) No, Hydro One does not adjust the expected service lives of different asset classes based upon the results of its asset condition assessment process, or its retirement records.

d) Hydro One's Expected Service Lives that are calculated based on depreciation rates are periodically reviewed by Foster Associates Inc. Following their review, Foster Associates may recommend a change to depreciation rates. These changes must be justified and approved by the Hydro One Corporate Controller.

OEB Staff Interrogatory # 126

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2004
(5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 1: Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile

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

Pole Replacement

The key recommended actions for pole replacement are outlined below.

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

Substation Refurbishment

The key recommended actions for substation refurbishment are outlined below.

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

Interrogatory:

Has Hydro One taken action to address these recommendations? Please provide details.

Response:

Please see details below for how Hydro One is addressing these recommendations.

Pole Replacement

1. Hydro One is considering including more quantitative pole testing methods within the existing line patrol program. The strategy currently being evaluated is to alternate detailed pole testing (for example: drilling and shell thickness measurements) with visual inspections. With this proposal the Distribution System Code Appendix C cycle length is maintained and detailed pole tests are obtained. Hydro One is continuously monitoring emerging technologies and will consider other non-destructive pole testing methods as they become available.

2. Please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6.3.1 for the actions Hydro One has taken to address Recommendation 2.

3. As documented on page 15 in Exhibit Q, Tab 1, Schedule 1, Attachment 1, Hydro One did utilize dedicated crews in 2017 and intends to continue to use dedicated crews where appropriate.

4. Please refer to interrogatory response Exhibit I-25-Staff-122 for the actions Hydro One has taken to address Recommendation 4.

Substation Refurbishment

5. Hydro One has implemented a formal data governance project as noted in Exhibit A, Tab 3, Schedule 1, Attachment 3. This project is to provide data completeness improvements where missing data exists, review data requirement needs, and to clarify ongoing accountability, processes and communication to monitor and remedy data issues.

   Specifically for station refurbishment projects, Hydro One has made changes to aid in the improvement of data governance through identification of station equipment that is missing in the SAP system. Hydro One is also in the process of developing reports to identify incomplete data points.

6. Hydro One has enhanced the cost estimating for all new station refurbishment projects. Prior to releasing the project for execution, a detailed cost estimate will be requested rather than prior practice of releasing each project based upon a unit cost.

7. As mentioned in Item 6, Hydro One has implemented a new cost estimating and project release process for all new station refurbishment projects that will allow for improved project cost monitoring. Further as mentioned in Item 5, the implementation of the data governance project will ensure improved data quality and completeness on station assets condition, demographics and criticality.

OEB Staff Interrogatory # 127

Issue:

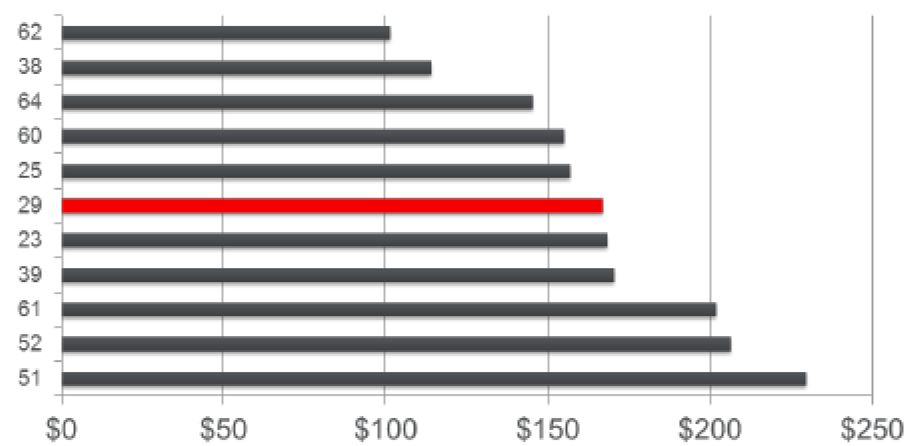
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2011

(5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 1: Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile, Figure 7 – Actual Annualized Life Cycle Costs per Pole per Year

Figure 7. Actual Annualized Life Cycle Costs per Pole per Year



Interrogatory:

a) Please explain why #62 and #38 have the lowest actual annualized life cycle costs per year? Do they pay less than Hydro One to install equivalent poles, or do their poles have a longer expected life?

b) Is there anything that Hydro One could do to improve its performance under this metric, or is it a function of external costs (such as the pole) and weather?

Response:

a) Companies 62 and 38 have some of the lowest installation / replacement costs within the group. Company 62 also has a long planned life for their poles.

b) The recommendations from the Navigant and First Quartile report suggested four potential practices that could impact the costs – while none is guaranteed to improve the lifecycle costs, there is reason to believe they would. The four actions, in summary, were
   - Perform more complete pole inspections on a longer cycle;
   - Manage a higher percentage of the pole replacements centrally;
   - Use dedicated pole replacement crews; and
   - Refurbish poles where appropriate.

OEB Staff Interrogatory # 128

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2030

(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 1: Pole Replacement and Station Refurbishment Program Study – Navigant and First Quartile.

"The key difference between most comparison utilities and Hydro One is that Hydro One does not evaluate testing results and/or maintenance history records as a primary driver when making replace versus repair decisions for switching and protection equipment or relays."

Interrogatory:

a) What does Hydro One use as the basis for making replace versus repair decisions?

b) Why does Hydro One use a different primary driver for these decisions than most comparison utilities?

c) What would be the ratepayer impact of adopting the use of testing results and/or maintenance history records as a primary driver for these decisions?

Response:

a) During routine station inspections, distribution station switches and relays found to be defective will be repaired if repairable. If they cannot be repaired, then they will be replaced. For specific models of switches which are prone to safety issues, the switches are replaced rather than repaired. Distribution station switches and relays may also be replaced as part of the integrated station refurbishment project (SR-06).

b) In recent years, Hydro One has adopted a condition based maintenance approach for distribution station assets, as described on page 21 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.1.3. Thus Hydro one performs visual inspections and condition based maintenance for switch and protection assets; whereas most other utilities perform visual inspections and time based maintenance for these assets. This has led Hydro One to use a different primary driver for these decisions than most comparison utilities.

c) In order to obtain test results and a maintenance history, Hydro One would need to change its preventive maintenance practices. The impact to the ratepayer would depend on the level and frequency of maintenance and testing.

OEB Staff Interrogatory # 129

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2041

(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 2: Hydro One Vegetation Management Study 2016.

> *"Although most of the peer group has lower costs than Hydro One, it is not always due to better performance than Hydro One. This is because fixed costs are higher. Some companies do show that cost per unit can be lower. In fact, one company maintains their system three times during the same time period that Hydro One maintains their system once and the cost for three cycles is still less than Hydro One's single cycle. (See p. 39 for more details)"*

Interrogatory:

a) Has Hydro One investigated why its per unit vegetation management costs are higher than most members of the peer group?

b) Has Hydro One considered implementing cost saving measures that would enable it to reduce its costs per cycle without reducing the effectiveness of its vegetation management program? Please include the implications of the December 21, 2017 update.
   i. If yes, please provide details of the cost saving measures being considered.
   ii. If no, please explain why not.

Response:

a) Yes. The "CN Utility Consulting – Hydro One Vegetation Management Study" filed in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6, Attachment 2, page 5 summarizes the key differences in unit costs between Hydro One and its peers.

b) Yes. Opportunities for cost savings through improved work execution strategies have been presented in interrogatory response Exhibit I-8-Staff-37 part (b). Additionally, Exhibit Q, Tab 1, Schedule 1 provides details on how the new defect based vegetation management approach will reduce unit prices and improve investment outcomes while working within the originally forecasted budget.

OEB Staff Interrogatory # 130

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2042-2043
(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 2: Hydro One Vegetation Management Study 2016.

"1.4 BEST MANAGEMENT PRACTICES
The following examples of vegetation best management practices (BMP) are based on industry standards and current industry practices.1

1.4.1 BEST MANAGEMENT PRACTICE STRATEGIES

1. *Perform consistent, compliant, and cost-effective ROW corridor management to maintain clearances between conductors and vegetation using industry-approved practices targeted to ensure reliable electric service, environmental quality, customer satisfaction, and safety for workers and the public.*
2. *Provide sufficient funding and resources to measurably achieve UVM program objectives. "A stable and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best practice (National Grid 2015)."*
3. *Build greater safety awareness and education for anyone who enters a ROW zone for any reason and measure success by using leading performance indicators, such as safe ROW environment metrics, safe work place metrics, and program features.*
4. *Define, measure, and audit the barrier space between conductors and vegetation.*
5. *Establish a cycle of inspection and maintenance that is sufficiently flexible to address a variety of vegetation management conditions but regular enough to anticipate conflicts before they occur.*

1.4.2 BEST MANAGEMENT PRACTICE TACTICS AND KEY MEASURES

Maintain 50-75% of distribution ROWs using industry-approved herbicides.
Cultivate and measure positive customer involvement with UVM.

Automate the UVM Program. See 4.3.2 for details

a) *Improve routing, deployment and management of crews through telematics technology and scheduling.*
b) *Use predictive analytics and modeling to improve performance and achieve best management practices.*
   Perform detailed outage investigations by forestry personnel and model data to promote understanding of tree conditions and failure modes.

Convert the majority of distribution ROW to low-growing shrubs and herbaceous plants.

Assess ROW edge trees routinely for risk and replace hazardous trees with appropriate vegetation.

Improve adjacent off-ROW vegetation to ensure desired percent of tree cover to provide appropriate benefits and protections. Trees provide vital ecosystem services and having the right trees adjacent to powerlines requires appropriate planting and maintenance strategies.

Establish common goals and maintain action-based relationships with various provincial and community forestry units that foster a reduction in necessary line clearing activities: Align various vegetation management activities in province of Ontario

Develop wood utilization programs as an organizing principle for sustainable harvesting and recycling of off-ROW trees before they become hazards. Trees provide many products and utility clearing can be a source of raw materials for wood products.

Develop land use programs such as food crops, pollinator habitats, recreational, emergency access, transportation, and other various land uses that are appropriate and beneficial for distribution ROWs."

Interrogatory:

Is Hydro One planning to implement the best management practices identified in 1.4.1 and 1.4.2?

i. If yes, please provide an outline and schedule for the implementation plan.
ii. If no, please explain why not.

Response:

Please see below for Hydro One's response for each practice.

1.4.1 BEST MANAGEMENT PRACTICE STRATEGIES

1. Perform consistent, compliant, and cost-effective ROW corridor management to maintain clearances between conductors and vegetation using industry-approved practices targeted to ensure reliable electric service, environmental quality, customer satisfaction, and safety for workers and the public.

Yes, this is a Hydro One practice. It is Hydro One's policy to execute the vegetation management program using:

1) an integrated vegetation management (IVM) approach;
2) work practices that comply with ANSI A300 – Tree Care Standards; and
3) a competent and qualified workforce that embraces Hydro One's core values.

Compliance is assessed through the Quality Assurance and Quality Control Program described in Exhibit Q, Tab 1, Schedule 1.

2. Provide sufficient funding and resources to measurably achieve UVM program objectives. "A stable and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best practice (National Grid 2015)."

Yes, Hydro One has implemented this practice. With the strategy outlined in Exhibit Q, Tab 1, Schedule 1 and funding requested, Hydro One will be able to maintain a stable and consistently funded preventative vegetation management program.

3. Build greater safety awareness and education for anyone who enters a ROW zone for any reason and measure success by using leading performance indicators, such as safe ROW environment metrics, safe work place metrics, and program features.

Yes, this is a Hydro One practice. Through the Environment, Health and Safety investments described in Exhibit C1, Tab 1, Schedule 4, Hydro One maintains and monitors the success of a rigorous internal health and safety management system. Further safety awareness is disseminated to the public during landowner notification, through bill inserts, and through media campaigns like those delivered in the vegetation management section of www.hydroone.com.

4. Define, measure, and audit the barrier space between conductors and vegetation.

Yes, Hydro One has implemented this practice. Compliance is assessed through Quality Assurance and Quality Control Program described in Exhibit Q, Tab 1, Schedule 1.

5. Establish a cycle of inspection and maintenance that is sufficiently flexible to address a variety of vegetation management conditions but regular enough to anticipate conflicts before they occur.

Yes, Hydro One has implemented this practice. Through the Defect Correction program, Hydro One's rights-of-way will be inspected and maintained on a three year cycle. The Defect Correction program will provide public safety and reliability risk mitigation in the short term. The Public Safety and Reliability program provides the flexibility to correct emergent issues that arise outside of the cyclical defect correction program.

1.4.2 BEST MANAGEMENT PRACTICE TACTICS AND KEY MEASURES

1. Maintain 50-75% of distribution ROWs using industry-approved herbicides.

Yes, Hydro One is working towards achieving this objective. Herbicide application is an important component of establishing and sustaining a low growing community of compatible vegetation on Hydro One's rights-of-way. However, in the near term, Hydro One's investments will be focused on clearing the maintenance backlog and resetting the maintenance cycle to three years across the system. After the first cycle, the workload in the defect correction program is expected to abate, which will provide the opportunity to invest more heavily in the herbicide program.

2. Cultivate and measure positive customer involvement with UVM.

Yes, this is a Hydro One practice. Hydro One has an extensive stakeholder notification program that precedes all planned work and provides the opportunity to cultivate positive customer involvement. Success is measured through customer satisfaction surveys after work is completed.

3. Automate the UVM Program. See 4.3.2 for details: (a) Improve routing, deployment and management of crews through telematics technology and scheduling. AND (b) Use predictive analytics and modeling to improve performance and achieve best management practices.

Yes, Hydro One is working towards achieving this objective through the technology innovation project outlined on page 19 in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6 that is planned for 2018.

4. Perform detailed outage investigations by forestry personnel and model data to promote understanding of tree conditions and failure modes.

Yes, Hydro One has implemented this practice. Detailed tree caused outage investigations are currently being conducted and are in scope of the Public Safety and Reliability program outlined in Exhibit Q, Tab 1, Schedule 1.

5. Convert the majority of distribution ROW to low-growing shrubs and herbaceous plants.

Yes, this is a Hydro One practice. Through the use of integrated vegetation management Hydro One seeks to convert rights-of-ways to a stable, low growing plant community.

6. Assess ROW edge trees routinely for risk and replace hazardous trees with appropriate vegetation.

Yes, Hydro One has implemented this recommendation. Hazard tree assessment and removal is in scope of the Defect Correction Program described Exhibit Q, Tab 1, Schedule 1.

7. Improve adjacent off-ROW vegetation to ensure desired percent of tree cover to provide appropriate benefits and protections. Trees provide vital ecosystem services and having the trees adjacent to powerlines requires appropriate planting and maintenance strategies.

Yes, Hydro One has implemented this recommendation. Through the hazard tree assessment process implemented in the Defect Correction program, Hydro One will be identifying and removing defect trees in the forest adjacent to the rights-of-way.

8. Establish common goals and maintain action-based relationships with various provincial and community forestry units that foster a reduction in necessary line clearing activities: Align various vegetation management activities in province of Ontario.

Yes, this is a Hydro One practice. Hydro One has strong relationships with local and provincial agencies and works with these organizations to deploy its vegetation management programs across the province.

9. Develop wood utilization programs as an organizing principle for sustainable harvesting and recycling of off-ROW trees before they become hazards. Trees provide many products and utility clearing can be a source of raw materials for wood products.

No, Hydro One will not be implementing this recommendation. However, Hydro One does actively search for opportunities to recycle wood waste generated during vegetation management operations, mostly through providing chipped wood waste to interested landowners.

10. Develop land use programs such as food crops, pollinator habitats, recreational, emergency access, transportation, and other various land uses that are appropriate and beneficial for distribution ROWs.

Yes, this is a Hydro One practice. Compatible secondary land uses on Hydro One's distribution rights-of-way are encouraged.

OEB Staff Interrogatory # 131

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2044

(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 2: Hydro One Vegetation Management Study 2016.

"1.7.1 UNIT COST

Hydro One reports high unit costs compared to the peer group. The high costs are due to heavy workloads associated with long cycle lengths, higher cost of labor and equipment, and better reporting of overhead costs by Hydro One as a result of having an in-house vegetation management program. (4.1)."

Interrogatory:

a) Could Hydro One achieve lower unit costs if some components of its vegetation management program were outsourced? Please explain in detail.

b) Could Hydro One catch up on its vegetation management backlog more quickly and economically by deploying outsourced labour in parallel with in-house crews? Please explain in detail.

Response:

a) Hydro One's ability to outsource vegetation management is restricted, by the collective bargaining agreement with the Power Worker's Union. With these restrictions, the opportunity for contract resources to lower the unit cost of the vegetation management program is minimal.

b) Yes, outsourced labour could help Hydro One catch up on its vegetation management backlog more quickly; provided that the outsourcing satisfied the conditions of the collective bargaining agreement with the Power Worker's Union as mentioned in part (a).

OEB Staff Interrogatory # 132

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 1.6 Page: 2045
(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 2: Hydro One Vegetation Management Study 2016.

"1.7.2 LABOUR EFFICIENCY

> *As shown in the 2009 study for the OEB, Hydro One continues to perform UVM at or below the average for number of labour hours expended per managed kilometre of overhead line. The result is a decade of efficient UVM performance. See Section (4.2)"*

Interrogatory:
How does Hydro One perform in cost efficiency versus hour-efficiency? Please provide a detailed explanation of the discrepancy.

Response:
See sections 4.1 and 4.2 for detailed discussions on cost and labour efficiencies. When comparing cost and labour hour efficiencies, it should be remembered that increases in cost may not be related to labour hour efficiency. CNUC calculated cost per labor hour by dividing the annual cost of UVM by the labour hours expended. The cost per labor hour (labour burden) increased from 2011 to 2015 at Hydro One (See Figure 5, section 4.1.4 and graphs 49 & 50 in Appendix J). As a result, increasing UVM costs diminished cost efficiency from 2011-2015, because there was not an adequate increase in unit productivity to match increasing costs.

The following are examples of increases in operational UVM costs that directly affect cost efficiency but may not affect labour hour efficiency:
1) Increased investments in wages, equipment, preplanning and technology
2) Increases in cost of doing business such as cost of living, inflation and increases related to vendor services and materials
3) Increases in corporate overhead costs applied to the UVM department

CNUC found positive cost efficiency longitudinally in comparison to peers for both managed and system mile cost. Said another way, the Figures show the Peer group to be increasing cost per system kilometre (Fig. 2, Sec. 4.1.2) and labour hours per kilometre (Fig.12, Sec.4.2.2.2) faster than Hydro One. Additionally, as Fig. 2. demonstrates, Hydro One's system kilometre costs were only 4% higher than the peer average in 2015. This may demonstrate cost efficiency but as the report notes it does not necessarily translate to program efficacy. By comparison, in 2015, Hydro One's managed kilometre cost was 49% higher than the peer group (Fig. 4, Sec. 4.1.3.2). Since the cost per labor hour was considerably higher for Hydro One in comparison to peers, it was concluded labour inefficiencies could not be firmly established as an indicator of cost inefficiencies in comparison to peers.

Higher cost per labour hour at Hydro One can in part be explained by the fact Hydro One vegetation management personnel are full-time company employees and part-time hiring hall employees who incur a higher hourly cost than vendor employees who are predominately used by the peer group (See Fig. 18 and Tbl. 4, Sec. 4.4.2). As Fig.18 demonstrates, wages are only a part of the labour burden and may only account for a percent of cost efficiency measurements.

Cost efficiency from 2011-2015 was not affected by increases in labour hours per unit of productivity. It was expected that Hydro One would have suffered losses in labour efficiency due to increases in trees density and biomass accumulations from a long cycle length. On the contrary, labour hours per managed kilometre remained relatively static 2011-2015 as shown in Fig.12.

In conclusion, Hydro One's cost per kilometre remains higher than the peer group partially because of a persistent history of long cycles between management that have led to increasing tree densities and biomass accumulations and partially because the costs per labour hour are significantly higher. Higher costs have been historically due to higher program costs related to equipment, wages, benefits, overheads, etc. In terms of cost per kilometre over time, Hydro One is not increasing as fast as the peer group.

OEB Staff Interrogatory # 133

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2045

(5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016.

"1.7.2.1 Labour Hours per System Kilometre

All of the Hydro One regions performed better than the peer average in this measurement. Rather than demonstrating work-efficiency, this metric is an indicator that Hydro One is under-resourcing their program and more work needs to be done. This is true because tree density, the number of trees managed per kilometre, is increasing and Hydro One has not been able to decrease the length of its cycle. (4.2.1)"

Interrogatory:

Why is under-resourcing evaluated in the study as "performed better"?

Response:

"Better performing" takes the perspective of fewer labor hours per system kilometer than peers. As the narrative explained, this can be a misperception if taken in the context of program efficacy.

OEB Staff Interrogatory # 134

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 2046
(5.2.3) Benchmarking, Section 1.6.4 Attachments: Benchmarking Studies, Attachment 2: Hydro One Vegetation Management Study 2016.
"1.7.6.1 Storms are Hydro One's Greatest Challenge

- *Hydro One's outage per system kilometre metric is an achievement given the length of management cycles, high tree densities, system size, and the propensity for storms in the South, Central, and East Regions.*
- *A high percent of outages, especially during storms are caused by trees on the Hydro One system."*

Interrogatory:

a) Given this finding, has Hydro One investigated if it could potentially improve its outage performance by focusing greater efforts during the forecast period on vegetation management, even if the increased vegetation management costs were offset by significantly reducing spending on renewal capital projects?

b) If not, why not? Please explain quantitatively.

Response:

a) As part of the Asset Management Process outlined in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.0, a number of vegetation management program alternatives were evaluated, including alternatives which accelerated the vegetation management program to quickly reduce backlog and lower the maintenance cycle length. Given the volume of backlogged maintenance and the significant rate impact associated with the increased investment to clear the backlog, an accelerated program was not selected as the proposed plan. Instead, Hydro One developed a new defect based vegetation management strategy (described in Exhibit Q, Tab 1, Schedule 1) that will deliver improved reliability without the cost increases required to achieve the same result under the full corridor clearing approach.

b) See response to part (a).

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 135

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 2
Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment.

"Hydro One's maintenance cycle exceeds 8 years and was identified in recent program assessments, including an Ontario Energy Board (OEB) report as the key driver of program performance, each recommending the cycle be shortened to improve reliability, public safety, and cost performance."

Interrogatory:

Please provide a citation for the referenced OEB report.

Response:

The statement should have indicated reports filed with the OEB. The reference is to the findings of the CNUC vegetation benchmarking studies filed with the OEB in proceeding EB-2009-0096 (Exhibit A, Tab 15, Schedule 2, Attachment 1) and proceeding EB-2017-0049 (Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6, Attachment 2).

OEB Staff Interrogatory # 136

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 2
Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment.

"Although the filed strategy is an improvement on historical programs, the 3 year cycle strategy proposed in this report will generate similar investment outcomes in one third the time."

Interrogatory:

a) Please explain in detail how it was determined that the proposed strategy "will generate similar investment outcomes in one third the time".

b) Has a mechanism been established to quantitatively validate the claimed investment outcomes if the proposed strategy is adopted? If yes, please provide details of the mechanism.

Response:

a) Hydro One's maintenance backlog is negatively affecting distribution system condition, reliability and is increasing maintenance costs. Through the new defect based approach, Hydro One will be achieving a full cycle in three years instead of eight, resulting in improved system condition, reliability and program costs in just over one third the time.

b) Vegetation Management outcomes will be monitored through the Performance Measurement and Outcome Measures process outlined in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4. Specifically, vegetation management cost per kilometer and vegetation caused interruptions will be monitored.

OEB Staff Interrogatory # 137

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 3

Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment Sect. 1.3 Reliability Results.

- *"Off-ROW tree and branch failures cause approx. 90% of all outages"*

Interrogatory:

a) Are off-ROW tree and branch failures responsible for 90% of outages from all causes, or 90% of vegetation-caused outages?

b) Was Hydro One not previously aware of the impact of off-ROW tree and branch failures? Why were these factors not addressed in the past?

Response:

a) The off-ROW tree and branch failures are responsible for 90% of the vegetation-caused outages.

b) Yes, Hydro One was aware of the impact of off-ROW trees, details on their impact and how they are managed can be found in on page 44 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.

OEB Staff Interrogatory # 138

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 3

Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment Sect. 1.4 Forecast Workload and Cost.

> *"It is estimated that 2.1 million trees will need work over the first 3-year cycle to achieve base level defect control, 700,000 trees per year as compared to 800,000 under the current work scope. The major difference in approach is an optimized defect-based work scope combined with a strategic brush control regimen that significantly reduces cost per km from the current $11,000 per km to an estimated $3,000 per kilometer for the first full cycle."*

Interrogatory:

a) Please show how the cost reduction from $11,000 to $3,000 per km for the first cycle of the new brush control strategy was calculated.

b) What is the likely range of cost savings if the new forestry strategy is implemented using Hydro One in-house forestry resources, given the unfamiliarity of Hydro One forestry personnel with this strategy and the associated work methods?

c) Would it be possible for Hydro One to utilize experienced contract forestry resources to expedite and control costs for the first cycle? If no, please explain why not.

Response:

a) Historical costs of $11,000 per km were based on a work scope of full right of way, edge to edge clearing with a goal of achieving clearance for an eight year cycle. The new strategy utilizes a three year cycle and a defect based approach. Two factors contribute to the lower unit cost are:
    1. A selective scope focusing mainly on high criticality defects; and,
    2. Controlling defects over a shorter time horizon (three years versus eight years).

    The average unit costs were developed by zone for the first cycle as described in Section 5.2 of Exhibit Q, Tab 1, Schedule 1, Attachment 2.

b) As documented in Section 2.1 of Exhibit Q, Tab 1, Schedule 1, Hydro One forecasts the total cost of the vegetation management program will not change with the implementation of the new vegetation management strategy. The new strategy will see a reduction in unit cost based on the defect maintenance approach; however Hydro One expects to incur some upfront costs related to rolling out the new program strategy. Hydro One is cautiously optimistic that, once the transition is complete, vegetation management costs may decrease by 2023.

c) Please refer to interrogatory response Exhibit I- 25-Staff -131.

OEB Staff Interrogatory # 139

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 4

Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Sect. 1.6 Key Findings.

*"**Reliability Modeling** –By implementing an optimal maintenance cycle, modified work scope and an analytics based hazard tree program, it is reasonable to expect a 20% to 40% plus improvement in reliability by the end of 2020. An analytics based hazard tree program requires funding beyond the baseline maintenance levels."*

Interrogatory:

If implementing the new forestry strategy achieves the projected reliability improvement results, will that enable deferral of any System Renewal capital expenditures? If no, please explain why not.

Response:

No, System Renewal investments are not solely required to maintain reliability. The rates of System Renewal expenditure are required to address asset degradation rates and prevent an increase of the backlog of assets in poor condition that would have to be addressed in the future. System Renewal expenditures also mitigate safety and environmental risks.

OEB Staff Interrogatory # 140

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 4
Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Important Safety Observation.

"Recommendations contained in this report suggest a renewed emphasis on the identification and mitigation of hazard trees, with an estimated 1.1m trees needing work over the first cycle. Hazard trees, by definition, pose a risk not only to electric facilities but also to workers. Exposure to the dangers associated with climbing and/or felling hazard trees is likely to be greater than previously experienced. Additional precautions are advised."

Interrogatory:

Does this observation argue for bringing in external contract resources that are more familiar with these conditions than are Hydro One in-house forestry resources?

Response:

No, the observation highlights the need to focus on ensuring safe work practices while executing a program heavily focused on hazard tree removal.

OEB Staff Interrogatory # 141

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 10
Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Outage Rates over Time.

"Outage analysis in relationship with time since last worked was challenging due to many of the feeders having remedial work performed on different sections in different years and variability of weather events year to year."

Interrogatory:

If Hydro One implements the proposed forestry strategy, is it anticipated to measurably improve performance during severe weather events? Please explain in detail.

Response:

Yes, it is reasonable to expect that measurable improvements will be realized during severe weather events.

Defect trees are more likely than green, healthy trees to fail under any circumstances, particularly during storms. Since the proposed forestry strategy will reduce the number of defect trees in the system, overall performance is expected to improve.

OEB Staff Interrogatory # 142

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 12
Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment.

"Improvements in tree-related reliability can lead to significant savings in other lines of business. A reduction in the number of outages results in less straight-time and overtime payroll for call center staff, trouble men and line crews. Additionally, there are avoided costs associated with a reduced number of damaged facilities."

Interrogatory:

a) Is it possible to estimate or quantify the expected reduction in damage to facilities with the available information?

b) If no, what additional information would be required to develop such an estimate?

Response:

a) Yes, it is possible to estimate or quantify the expected reduction in damage to facilities with the available information.

b) See response to part (a).

OEB Staff Interrogatory # 143

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 13

Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment.

"Sixty seven percent (67%) of the current and 3-year projected defect workload (Table 6) is related to off-ROW trees (contacts and hazard trees combined) suggesting a need for increased focus on Off-ROW vegetation, specifically hazard trees."

Interrogatory:

Will management of off-ROW hazard trees and vegetation be significantly constrained by the rights of the landowners upon whose properties the trees are situated?

Response:

No. Since the identified off-ROW hazard trees and vegetation defects pose a near-term failure risk (within three years), it is not expected that their management will be significantly constrained by landowner rights.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 144

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

Q-01-01-02 Page: 13

Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment.

"Assuming a shortened maintenance cycle is implemented and once the first cycle is completed, going forward the number of defects and future workload will be greatly reduced."

Interrogatory:

Please estimate the second cycle costs, broken down by the same categories shown in Table 6 on pg. 13.

Response:

The workload categories presented in Table 6 of Exhibit Q, Tab 1, Schedule 1, Attachment 2 were derived from a detailed workload inventory conducted in 2017 and are a reflection of current system conditions. To be able to forecast workload to that level of detail for the second cycle would require more information about the system conditions as experience is gained with the first cycle of the program.

At this time, Hydro One is only able to provide a general forecast of anticipated total defects by zone for the three year period (2021 to 2023) for the Defect Correction program and total cost based on 2017 dollars as presented in the table below.

Defect Correction Program Second Cycle (2021 to 2023) Forecast					
	Zone A	**Zone B**	**Zone C**	**Zone D**	**Total**
Defects	451,336	339,206	440,570	211,121	1,442,233
Costs (2017 Dollars)	$77.8M	$48.4M	$70.4M	$31.8M	$228.4M

Note: these costs do not reflect the Public Safety/Reliability and the Quality Assurance /Quality Control programs.

OEB Staff Interrogatory # 145

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.6 Page: 2554
(5.4.4) Capital Expenditure Summary, Section 3.6.3 (5.4.4) Impact of Capital Investment on Operations, Maintenance and Administration Spending.

> *"Hydro One is investing in mobile technology to improve the productivity of the Provincial Lines organization. The investment will reduce inefficiencies, time delays and data inaccuracies in the scheduling, dispatching and execution of work completed by Provincial Lines. The investment will leverage existing technology like SAP and Hydro One's geographical information system. The investment is expected to achieve a five percent productivity gain across the organization which will translate to total annual savings of $13 million, $3 million of this being directly related to OM&A (ISD GP-10)."*

Interrogatory:

Will Hydro One be able to verify the projected 5% productivity gain, and demonstrate the link to the proposed mobile technology investments? Please explain in detail.

Response:

Please reference the response provided in Exhibit I-25-Staff-123.

OEB Staff Interrogatory # 146

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 3.6 Page: 2554
(5.4.4) Capital Expenditure Summary Section 3.6.3 (5.4.4) Impact of Capital Investment on Operations, Maintenance and Administration Spending.

> *"Hydro One serves approximately 1.3 million customers. To effectively manage customer accounts, there are between 10,000 and 21,000 trips each year to disconnect and reconnect customers. An investment in meters with remote connect and disconnect functionality is planned to eliminate approximately 6,000 of these trips each year. This will result in estimated annual OM&A savings of $4.5 million (ISD SS-01)."*

Interrogatory:
a) Will Hydro One be able to verify that the projected savings were achieved, and to demonstrate the link to the proposed investments?

b) Has Hydro One prioritized which customers will have meters with this functionality installed? How were these customers prioritized?

Response:
a) Hydro One will be able to verify that projected savings associated with remote meters were achieved and demonstrate the link to the proposed investment.

b) Hydro One currently prioritizes premises where two consecutive field visits are anticipated, within a short period of time. The scenarios include:

- Customer Requested Disconnections – When electrical or forestry work is being completed;
- Vacant Premises – When the previous tenant has moved out of the premise but no one has contacted Hydro One to set up a new account at the premise; and

- Disconnection for Non-Payment – Customers who have gone through Hydro One's collections process (including all notice periods outlined in the Distribution System Code) and are planned for disconnection for non-payment in the near future.

OEB Staff Interrogatory # 147

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2575
(5.4.5.2) Attachments: Material Investments, ISD: SA-03 Meter Infrastructure Expansion Program.

> ***"Alternative 2: Expand the meter infrastructure network (Recommended)***
>
> *Expand the meter infrastructure network by leveraging the Carriers upgrades by installing collectors, repeaters and executing configuration changes to improve communicate reliably with meters. This alternative is recommended as it will reduce the resource requirements of manual meter reads and improve Hydro One's billing accuracy by reducing the number of meters with unreliable communication to 96,564 from 123,000 by the end of the five year period."*

Interrogatory:

a) Please confirm if the implied accuracy of the values 123,000 and 96,564 given in this description is based upon using the same number of significant figures.

b) Please quantify the annual ratepayer benefits that will be achieved by spending $14.3M to improve the communications to 26,000 presumably remote meters?

Response:

a) They are different significant figures. 123,000 represented a high level estimate of the remaining OEB exemption meters when referenced against our total population of 1,300,000 meters, while 96,654 represents the remaining exemption population after expansion based on a detailed analysis.

b) The annual ratepayer benefit is approximately $600,000/year in avoided manual meter reading costs.

OEB Staff Interrogatory # 148

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2728
(5.4.5.2) Attachments: Material Investments, ISD: GP-07 Corporate Performance Reporting.

"Savings from the above are expected to be achieved beginning in 2020. These savings include a potential reduction in staff necessary to support the current program, avoided vendor enhancement work, and elimination of vendor annual support fees, which are currently $500k per year, (50% of which is attributable to Hydro One Distribution)."

Interrogatory:

a) How and where will these savings be tracked?

b) Please provide the scope of work for this project complete with resources required and the project schedule.

Response:

a) The savings identified are classified as cost avoidance and do not meet the criteria for productivity tracking at the corporate level. The costs associated with maintaining and updating the legacy software will no longer be incurred and the associated impact will be reflected as an avoided cost to the associated vendor support budget. Upon realization of the potential staff reduction any incremental savings that can be validated will be reported through Hydro One's productivity process which is described in Exhibit I-25-Staff-123.

b) An updated ISD: GP-07 Corporate Performance Reporting has been provided in response to OEB Staff Interrogatory # 173. This project is now scheduled to start in 2019 and will be completed in 2020. The updated cost of the project over the plan period 2018-2022 is $2.8 million. This update was reflected in Exhibit Q/Tab1/Schedule 1, Section 1.2: A Reduction in the Capital Forecast; Updated Rate Base and In-Service Additions Forecasts, capital forecast update for the years 2018-2022 due to adjustments made to General Plant projects, as filed December 21, 2017.

<u>Scope of work</u>

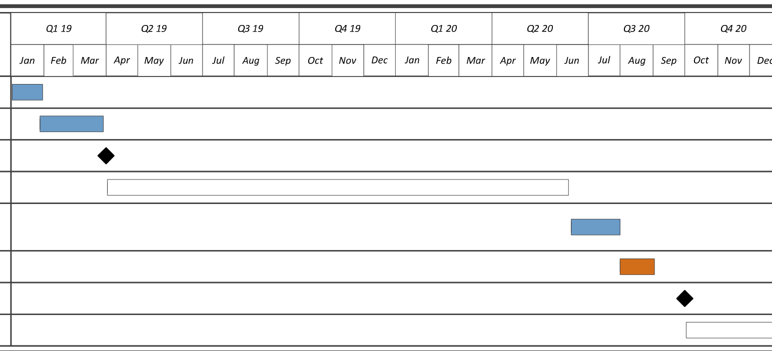
- Gather a comprehensive set of detailed requirements for Key Performance Indicators (KPI), functionalities, reports and visualization. Identify the needed KPI.
- Rationalize the outputs required and the inbound data needed to support analysis and identify data sources required to calculate those KPIs.
- Identify the new reports required to satisfy the line of business requirements.
- Design the solution based on the detailed requirements and produce the Functional Design Documents and Technical Design Documents.
- Establish the recommended platform the tool should be built on and incorporate data extracts of the analyzed data for external stakeholders and internal reporting.
- Migrate the necessary historic data from current Oracle application into SAP and/or other suitable enterprise tools.
- Develop required test plans, test documents, training materials / job aids / User Guides.
- Engage Change Management to guide the stakeholders in the transition to the new self-service model and support delivery of training to line of business users.
- Post Go Live support.

Resources Required

Hydro One Resources	$100,000
Change Management	$50,000
System Integration Vendor	$2,300,000
Overhead + Interest	$350,000
Total	$2,800,000

Project Schedule

ID	Task Name	Start	Finish	Duration
1	Initiation	1/2/2019	1/30/2019	4.2w
2	Engage / Source	1/28/2019	3/29/2019	9w
3	BCS Approved	4/1/2019	4/1/2019	0w
4	Design / Build / Test	4/2/2019	6/12/2020	62.8w
5	Cut-over	6/15/2020	7/30/2020	6.8w
6	Post cut-over support	7/31/2020	9/1/2020	4.6w
7	In Service	10/1/2020	10/1/2020	0w
8	Project Close Out	10/2/2020	12/30/2020	12.8w



OEB Staff Interrogatory # 149

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2733
(5.4.5.2) Attachments: Material Investments, ISD: GP-08 PCMIS Modernization and Optimization.

> *"Investment Description:*
>
> *The project will maintain and further strengthen PCMIS as the single source of record for all P&C device settings. PCMIS supports users across the enterprise as well as engineering and field personnel in external utilities, providing centralized, controlled access to cyber-sensitive data. The system ensures that the configuration of critical grid protection systems is accurate and manages approval of any settings changes, supporting numerous key business processes including planning, construction, maintenance, repair, network operating and outage management. PCMIS data is used by the Distribution Management System ("DMS") to support advanced power system application analytics."*

Interrogatory:

Please explain how these expenditures relate to the expenditures identified in GP-03 to GP-06. Are there any overlaps between these programs? Please describe in detail.

Response:

The current PCMIS solution is a custom application with significant limitations as outlined in ISD GP-08. The software is currently at its end of life, and it does not meet all of the business requirements of Hydro One. In order to fulfil operational requirements Hydro One is evaluating new solution options as well as processes and interfaces. As this would be a net new solution, its implementation would not be considered as an enhancement or upgrade funded out of investments outlined in GP-03/GP-04/GP-05/GP-06.

OEB Staff Interrogatory # 150

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2741
(5.4.5.2) Attachments: Material Investments, ISD: GP-10 Work Management & Mobility.

> *"A commitment to achieve at least a five percent productivity gain was established, with a projected return on investment of 21.3% and projected ongoing annual savings of $12 million."*

Interrogatory:

Please explain in detail how the projected productivity gain was calculated, and explain how the actual results will be reliably monitored and reported.

Response:

Please reference the response provided in Exhibit I-25-Staff-123.

OEB Staff Interrogatory # 151

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2743
(5.4.5.2) Attachments: Material Investments, ISD: GP-10 Work Management & Mobility

> *"In addition to a minimum five percent productivity gain for the Forestry, Stations and Corporate LOBs, there are also qualitative benefits in the areas of employee safety, customer service and employee engagement."*

Interrogatory:

Please provide a list of the expected qualitative benefits, including concrete examples of each.

Response:

The expected qualitative benefits are as follows:

Employee Safety:

- Safety hazards at customer premises are displayed on the tablet for the field member to refer to and review to ensure they can safely perform their work.
- Supervisors no longer print out paper packages to provide to their field forces. All the information the field member needs to complete the job is included in the job details that are accessible through the tablets. This allows the field supervisor to spend more time in the field doing work place safety observations.

Employee Engagement:

- Field members are provided with the tools and information they need to be able to update customer premise hazards real time and perform their job. In the past, field members were dependent on data entry at a later time for use in their next site visits.

Customer Service:

- Field members have real time access to information while they are on-site. This enables them to respond to customer questions and requests more expeditiously.

OEB Staff Interrogatory # 152

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
B1-01-01 Section 3.8 Page: 2763

(5.4.5.2) Attachments: Material Investments, ISD: GP-14 Warehouse Scanning Device Replacement

Interrogatory:
*"**Result:***
This investment will yield operational efficiencies. By proceeding with this investment, Hydro One will be able to monitor its inventory with better accuracy and speed, leading to greater efficiency."

a) Please provide quantitative support for the claimed efficiency gains.

b) Please provide a cost/benefit calculation demonstrating that ratepayers will obtain value from the proposed investment.

Response:
a) An updated ISD: GP-14 Warehouse Scanning Device Replacement has been provided in response to Exhibit I-29-Staff-173. This project has been cancelled to take into account changing business priorities and may be revisited post implementation of ISD: GP-17 S4 HANA. This update was reflected within the Evidence Update, 2017-12-21 Exhibit Q, Tab 1, Schedule 1 - 1.2 capital forecast update for the years 2018-2022 due to adjustments made to General Plant projects.

b) Please refer to part a) above.

OEB Staff Interrogatory # 153

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2775
(5.4.5.2) Attachments: Material Investments, ISD: GP-17 S4 HANA for Finance

Interrogatory:

*"**Investment Need:***
IT Need SAP has announced that they will stop improving the current enterprise BI platforms immediately and vendor support for the current platform altogether will end in 2025. SAP will shift development to their new SAP S/4 HANA platform. All business functions performed on the current platform will ultimately have to migrate to the new platform."

a) Please explain how this migration project impacts the other IT Capital expenditures.

b) Could implementation of the SAP platform cause delays or cost escalation for the other listed information technology projects?

c) Does Hydro One have a critical dependency upon SAP software or services? If yes, please explain what steps Hydro One is taking to mitigate the potential cost pressures resulting from this single-source dependency.

Response:

a) Hydro One is relying on the SAP platform and suite of products, which includes ERP Central Component (ECC), Business Intelligence (BI) and Customer Information System (CIS) for its transactional processing and reporting requirements. The company intends to leverage the database that comes with the S/4HANA platform to consolidate over time the requirement for its various SAP applications (e.g. ECC, BI, CIS) and potentially the GIS Mapping software (ESRI). This project to a degree will reduce the complexity of the technical environments, albeit it may not reduce the expenditures of other IT Capital investments as investments will be required to facilitate the consolidation.

b) Evidence Update provided in Exhibit Q, Tab1, Schedule 1 - 1.2 capital forecast update for the years 2018-2022 due to adjustments made to General Plant projects takes due recognition of the impact and dependencies (if any) of other SAP-related investments. Other than these, this investment should not negatively impact the cost and schedule of other investments, outside of the normal recalibration of activities as part of IT operations.

c) Hydro One uses many applications in the process of managing the business. To mitigate potential cost pressure related to Hydro One's SAP solution the system is kept at vendor supported patch levels where standard SAP support mechanisms apply. SAP support rates are negotiated and known well in advance. Should Hydro One not maintain vendor supported levels there could be considerable application maintenance costs in procuring extended support or emergency support.

OEB Staff Interrogatory # 154

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.6 Page: 1994 - 1997
(5.2.3) Benchmarking, Vegetation Management Program Study
Office of Auditor General of Ontario – Annual Report 2015 (Rec. 10)

Interrogatory:

The Auditor General's report recommended the following:

"To lower costs and ensure Hydro One's vegetation-management program is effectively reducing the number of tree-related outages experienced by its distribution system customers, Hydro One should:

- *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) Please explain how the technology innovation project proposed by Hydro One addresses the recommendation to shorten the vegetation management cycle to a four to eight year cycle.

b) Please provide the specifications of the automated Utility Vegetation Management (UVM) program including but not limited to the input parameters, evaluation algorithm, and final output.

c) Please provide the sources of the data analytics and the operational philosophy of the predictive model.

d) Does the UVM program prioritize lines with poorer reliability and large customers that require higher reliability? If so please explain the method of prioritization and how it addresses the recommendation from the Auditor General's report.

Response:

a) The technology innovation project will allow Hydro One to effectively capture this data, generate map based, digital work packages, and report on work completed. By utilizing this technology, it is expected that work execution will become more efficient, and new intelligence gained through the workload catalogue will improve Hydro One's ability to identify targeted, high impact maintenance.

   Furthermore, through the new vegetation management strategy outlined in Exhibit Q, Tab 1, Schedule 1, Hydro One is moving its system to a three year defect based maintenance cycle.

b) Building an automated Utility Vegetation Management program is within the scope of the technology innovation project which is in a development stage and specifications are not available at this time.

c) See answer to part (b), above.

d) Yes, consistent with Recommendation 9 of the Auditor General's report, the UVM program uses reliability and voltage classes to prioritize lines for clearing. In any given program year, M-Class feeders and feeders with an above-average SAIDI contribution are prioritized for clearing.

OEB Staff Interrogatory # 155

Issue:
Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:
Office of Auditor General of Ontario – Annual Report 2015 (Rec. 14)

Interrogatory:
The Auditor General's report recommended the following:

> *"To 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"*

a) What functionality does Hydro One's Distribution Management System currently have with smart meters?

b) Does Hydro One pinpoint power outages through smart meter capability? If not, does Hydro One have a plan to? Please provide the plan if available.

c) If there is a plan please provide the expected total cost to implement this technology and the expected cost savings once fully implemented.

Response:
a) While the Distribution Management System uses accurate load profiles generated from smart meter information, it does not connect to the smart meters directly. The Advanced Metering Infrastructure for Operations system leverages smart meters.

b) Yes. Hydro One does pinpoint outages through its smart meter capability. A new Advanced Metering Infrastructure for Operations system was implemented by the Advanced Distribution System project that enables direct intelligent pinging of meters (upstream and downstream from the target meter) from the Distribution Operations Management Centre. The Advanced Metering Infrastructure for Operations system also receives the real-time power outage notifications from smart meters to inform dispatchers of outages before customers call. The same system also receives real-time power restoration notifications that enable dispatchers to confirm restoration of power.

c) The Advanced Metering Infrastructure for Operations has delivered significant benefit in avoiding unnecessary crew dispatches. By providing dispatchers the ability to ping meters and verify the scope of power outages, they are able to avoid sending out crews when there are no power outages. While overall costs will vary year-to-year based on weather, this investment has help avoid $2M per year in crew dispatch costs which is reflected in the current investment plan.

OEB Staff Interrogatory # 156

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2546 - 2550
(5.4.5.2) Attachments: Material Investments, ISD: SR-03 Station Spare Transformer Purchases Program
Office of Auditor General of Ontario – Annual Report 2015 (Rec. 15)

Interrogatory:

The Auditor General's report recommended the following:

"To reduce its excess inventory of spare transmission and distribution system transformers to an appropriate cost-effective level, and to lower costs while still being able to replace failed transformers in a timely manner, Hydro One should:

- *improve the forecasting model it uses for predicting transformer failures, and maintain its inventory levels of spare transformers in accordance with the forecasts*
- *develop a plan to standardize in-service transformers as much as possible, and set targets and timelines for achieving savings from better managing both spare and in-service transformers."*

a) Please provide the number of distribution station transformer failures in the last five years including the cause of failure, age, and specifications of each transformer.

b) How does Hydro One currently forecast the number of expected transformer failure for any given year?

c) Has Hydro One begun to standardize in-service transformers for distribution stations? If so, please provide the specifications of the ideal set of standardized transformers.

d) Does the transformer inventory in investment SR-03 only include distribution transformers? If so, please explain the planned capital investment that would keep 149 in the inventory when the Auditor General's report identified 35% of the spare transformer stock (140 distribution transformers and 60 transmission transformers) is not required.

Response:

a) Please see table below for the distribution station transformer failure data over the last five years.

Year	Class	Station - Transformer	Age at Failure	MVA	Phase	HV	LV	ULTC	Failure Details
2012	1	Golden Lake DS - T1	23	6	Three	44	12.47	yes	ULTC failure.
2012	1	Long Lac East DS - T1	58	1	Single	44	7.2	no	Internal winding failure during lightning storm.
2012	1	Red Rock DS - T1	48	2	Single	115	7.75	no	Transformer failed. Oil samples revealed DGA problems in the main tank.
2012	1	South Gower DS - T1	48	5	Three	44	8.32	yes	Customers complained of flickering lights (not interrupted). Transformer was inspected, ULTC found to be damaged. Also high partial discharge in main tank.
2012	2	Bismark DS - T1	41	5	Three	27.6	8.32	yes	High DGA in main tank discovered through routine sampling.
2012	2	Cranberry Lake DS - T1	43	6	Three	44	12.47	no	DGA indicated gassing. Internal inspection showed burning on internal connections.
2012	2	Elginburg DS - T1	43	5	Three	44	8.32	no	High DGA in main tank discovered through routine sampling.
2012	2	Gananoque DS - T1	29	10/13.3/16.6	Three	44	27.6	no	Routine oil results indicated high energy discharge in main tank.
2012	2	Haycroft RS	46	6	Three	8.32	8.32	yes	ULTC failure
2012	2	Marthaville DS - T1	40	5	Three	27.6	8.32	yes	Reversing switch repaired on site, found to source of gassing
2012	2	Rockwood DS - T1	25	6	Three	44	12.47	yes	High DGA in main tank discovered through routine sampling.
2012	2	Thamesville North DS - T1	39	5	Three	27.6	8.32	yes	ULTC failure
2013	1	Bowmanton DS – T1	36	5	Three	44	8.32	yes	Internal winding failure.
2013	1	Horsey Bay DS – T1	35	5	Three	44	8.32	no	Internal winding failure during lightning storm.
2013	1	Madawaska DS – T1	45	6	Three	44	12.47	yes	Transformer failed during installation.
2013	1	Maitland DS – T1	51	3	Three	44	8.32	no	Internal winding failure.
2013	1	Margach DS – T2	33	7.5	Three	115	27.6	yes	Routine DGA revealed transformer failed within main tank. Load was transferred to T1.
2013	1	Midhurst DS – T1	26	10	Three	44	8.32	no	Internal winding failure due to a line to ground fault within the station.

Year	Class	Station - Transformer	Age at Failure	MVA	Phase	HV	LV	ULTC	Failure Details
2013	1	Milford DS – T1	63	2	Three	44	8.32	no	Internal failure during line switching.
2013	1	North Augusta DS – T1	46	3	Three	44	8.32	no	Internal winding failure during lightning storm.
2013	1	St. Onge DS – T1	37	5	Three	44	8.32	no	Internal winding failure during lightning storm
2013	2	Angus DS – T1	41	5	Three	44	8.32	no	Internal winding failure discovered through routine DGA.
2013	2	Honey Harbour DS – T1	52	6	Three	44	12.47	no	High moisture in main tank discovered through routine oil sampling.
2013	2	Leamington RS - R1 (was repaired)	23	25	Three	27.6	27.6	yes	High moisture in ULTC discovered through routine oil sampling.
2013	2	Marmion DS - T1	44	5	Three	44	8.32	yes	High moisture in ULTC discovered through routine oil sampling.
2013	2	Millbrook DS – T1	47	5	Three	44	8.32	no	High DGA in main tank discovered through routine sampling.
2013	2	Sutton Baseline DS #1 - T1	47	5	Three	44	8.32	no	High moisture in ULTC discovered through routine oil sampling.
2013	2	Welland Effingham DS – T1	42	5	Three	27.6	8.32	yes	High DGA in main tank discovered through routine sampling.
2014	1	Lythmore DS – T1	46	5	Three	27.6	8.32	no	Internal winding failure during lightning storm
2014	1	Post Creek DS – T1	54	3	Three	44	12.47	no	Internal winding failure.
2014	1	Shannonville DS – T1	55	3	Three	44	8.32	no	Internal winding failure.
2014	1	Snelgrove DS – T2	38	5	Three	44	8.32	no	Bushing failure, aluminum foil in main tank. Transformer was blowing HV fuses.
2014	2	Chelmsford DS – T1	45	6	Three	44	12.47	yes	Internal winding failure discovered through routine DGA.
2014	2	Grand Bend DS - T1	47	15/20/25	Three	115	29.5	yes	ULTC failure
2014	2	Merrickville RS – R1	41	37	Three	44	8.32	yes	High DGA in main tank discovered through routine sampling.
2014	2	Rama DS – T1	22	7.5	Three	44	8.32	yes	Internal winding failure discovered through routine DGA.
2015	1	Crilly DS – T1 (red phase)	39	0.5	Three	25	7.2	no	Internal winding failure.
2015	1	Perrault Falls DS – T1	67	1	Three	115	12.47	no	Internal winding failure.
2015	1	Thorold Defoe DS – T1	49	5	Three	27.6	13.8	no	Internal winding failure.
2015	2	Azilda DS – T1	37	6	Three	44	12.47	yes	ULTC failure
2015	2	Browns Junction RS – R1	8	25	Three	44	44	yes	High DGA in main tank discovered through routine sampling.

Year	Class	Station - Transformer	Age at Failure	MVA	Phase	HV	LV	ULTC	Failure Details
2015	2	Taunton DS – T1	10	12	Three	44	27.6	no	High DGA in main tank discovered through routine sampling.
2015	2	Waterloo Oxford Co-op Norwich CDS – T1	45	1	Three	27.6	0.6	no	Major oil leak.
2016	1	Carleton Place Edmund DS - T1	39	5	Three	44	4.16	no	Internal winding failure.
2016	1	Corbeil DS - T1	65	0.667	Single	44	7.2	no	Internal winding failure.
2016	1	Kingston Woodbine DS - T1	25	10	Three	44	8.32	no	Internal winding failure.
2016	1	Pinelands DS - T1	48	6	Three	44	12.47	yes	Internal winding failure.
2016	1	Russell DS - R1	50	6	Three	8.32	8.32	yes	ULTC failure
2016	1	Wesley DS - T1	30	10	Three	44	27.6	yes	Internal winding failure.
2016	2	Bath DS - T1	46	5	Three	44	8.32	yes	High moisture in main tank discovered through routine oil sampling.
2016	2	Glen Meyer RS - R1	26	25	Three	27.6	27.6	yes	ULTC failure
2016	2	Listowell Davidson DS	46	5	Three	44	4.16	no	High moisture in main tank discovered through routine oil sampling.
2016	2	Smith Falls DS - T1	41	5	Three	44	8.32	no	High moisture in main tank discovered through routine oil sampling.
2016	2	Thorold Front DS - T1	63	5.4	Three	13.8	4.16	no	High moisture in main tank discovered through routine oil sampling.
2016	2	Washago DS - T1	46	5	Three	44	8.32	yes	High DGA in main tank discovered through routine sampling.

b) Hydro One forecasts the number of expected transformer failures primarily based on failure trending over the last five years. The planned number of high risk transformer replacements as well as the age of the population is also taken into consideration.

c) Yes, Hydro One has begun to standardize in-service three phase step-down transformers for distribution stations. The following two tables contain the specifications of Hydro One's standardized transformers:

Transformers with Under-Load Tap Changers (ULTC)

Item No.	MVA Ratings	Voltage Ratings (kV)	DETC in HV	ULTC in LV
A 1	7.5	27.6-8.8/5.1	No	±15% , ±12 steps
A 2	7.5	44-8.8/5.1	No	±15% , ±12 steps
A 3	7.5	44-13.2/7.6	No	±15% , ±12 steps
A 4	12	44-26.5/15.3	No	±15% , ±12 steps
A 5	12	44-29.3/17	No	±15% , ±12 steps
A 6	7.5/10/12.5	115.5-8.8/5.1	No	±20% , ±16 steps
A 7	7.5/10/12.5	115.5-13.2/7.6	No	±20% , ±16 steps
A 8	7.5/10/12.5	115.5-26.5/15.3	No	±20% , ±16 steps
A 9	15/20/25	115.5-29.3/17	No	±20% , ±16 steps
A 10	5	27.6-8.8 x 4.4	No	±15% , ±12 steps
A 11	5	44-8.8 x 4.4	No	±15% , ±12 steps
A 12	10	44-13.2/7.6	No	±15% , ±12 steps
A 15	20/27/33	115.5-29.3/17	No	±20% , ±16 steps
A 17	10	44 – 8.8/5.1	No	±15% , ±12 steps
A18	7.5	44-26.5/15.3	No	±15% , ±12 steps
A19	10/13/2016	44-29.3/17	No	±15% , ±12 steps
A20	5	13.8-8.32	No	±15% , ±12 steps

Transformers with De-Energized Tap Changers (DETC)

Item No.	MVA Ratings	Voltage Ratings (kV)	DETC in HV	ULTC in LV
B 1	7.5	27.6-8.8/5.1	±(2x2.5%)	No
B 2	7.5	44-8.8 x 4.4	±(2x2.5%)	No
B 3	7.5	44-13.2/7.62	±(2x2.5%)	No
B 5	1	27.6-600/347	±(2x2.5%)	No
B 6	1	44-600/347	±(2x2.5%)	No
B 7	5	27.6-8.8 x 4.4	±(2x2.5%)	No
B 8	10	44-8.8/5.1	±(2x2.5%)	No
B 9	10	44-13.2/7.6	±(2x2.5%)	No
B 10	12	44-29.3/17	±(2x2.5%)	No
B14	5	44-8.8 x 4.4	±(2x2.5%)	No

d) Yes, the transformer inventory in ISD SR-03 includes distribution station transformers only. The 149 optimum level of transformers identified in SR-03 is a combination of spare transformers (99), and transformers available for project usage (50). The transformers available for project usage will be deployed to planned and demand projects to reduce the total inventory.

At the time when the Auditor General gathered their data in 2015, Hydro One Distribution had 140 station spare transformers in inventory, and 27 transformers on order for a total of 167 transformers. Hydro One's plan to manage distribution station transformers involves a reduction of 40% over a 10 year period to yield a spare inventory count of approximately 100 transformers by 2025.

OEB Staff Interrogatory # 157

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 3.8 Page: 2624 - 2628
(5.4.5.2) Attachments: Material Investments, ISD: SS-03 Reliability Improvements
Office of Auditor General of Ontario – Annual Report 2015 (Rec. 16)

Interrogatory:

The Auditor General's report recommended the following:

"To 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."

Does Hydro One currently use power meters to address power quality issues on the distribution system? If not, why? If so, please explain how Hydro One uses power meters to define power quality events?

Response:

Hydro One has been proactively installing power quality ("PQ") meters at the point of common coupling of our large distribution account customers. These meters are setup to capture two types of data:

- Triggered event data during disturbances, which are comprised of short duration, high resolution data captured only when a designated monitored quantity deviates beyond specified thresholds. These data are used by HONI:
    - to conduct an investigation in response to customer complaints, to identify the root cause of an experienced problem, and where appropriate to identify remedies;
    - to gain insight into the degree of sensitivity or immunity of the plant's equipment to PQ events.
    - to identify the need to improve feeder performance and hence the PQ performance.

- Steady-state performance data on a 24/7 basis, which is generally comprised of averaged measurements taken over specified time-spans in accordance with industry standards, to provide trend analysis aimed at verifying that the delivery point PQ is in compliance with the Distribution System Code or related requirements.

School Energy Coalition Interrogatory # 50

Issue:

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

Reference:

B1-01-01 Section 2.1 Page: 12

Interrogatory:

Please explain how Hydro One takes into consideration the trade-off between replacing or refurbishing an asset, and undertaking maintenance activities for the asset.

Response:

The methodology for which Hydro One makes replacement, versus refurbishment and maintenance decisions is asset specific. Many factors are taken into consideration when making the decision to replace, refurbish or maintain the asset. The primary factors in that decision generally involve the condition of the asset, the cost to the system to repair or refurbish the asset, and the impact of the asset's performance on customers. For specific asset life cycle strategies, please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3.

The Society of Energy Professionals Interrogatory # 2

Issue:

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

Reference:

B1-01-01 Section 1.5

In the last Hydro One Distribution major application before the OEB, EB-2013-0416, The Society submitted an interrogatory I-3.03-12 SEP 9 requesting that Hydro One identify the annual cost savings from shifting the administration of its employee benefits program from Great West Life to Green Shield Canada (see Attachment 1).

Hydro One responded that it anticipated cost savings from this change however "the savings cannot be quantified at this time since we have not had enough experience with the new provider", and further, no such savings were included.

In this current proceeding, Hydro One has not identified any such productivity savings resulting from this change in service providers of its administration of its employee benefits program. [Ref. B1-1-1, DSP Section 1.5 "Productivity and Continuous Improvement"]

Interrogatory:

a) Please provide the annual cost savings resulting from this change for 2014 to 2022 for both HONI and HONI Distribution. Also provide the OM&A and capex split of these savings.

b) Where are these cost savings included in the filed evidence?

Response:

Hydro One did not track the requested information. A changing benefits landscape including the emergence of specialty drugs and rising prices means the benefit plan experience with Hydro One's previous provider cannot be compared directly with its current provider. Administrative rates at the time of the contract award were guaranteed for a five-year period and continue to be competitive based on the market. Green Shield Canada follows Hydro One's plan design in its adjudication of health and dental claims and their audit practice, knowledge and integration of other government programming ensures the maximum opportunity for plan value.

The referenced savings would not be called out in the Application as they are realized savings, not targets and pre-date the Business Plan. Such savings would be reflected in cost forecasts before adjustments for the productivity targets identified in section 1.5 of the DSP and updated in Exhibit I-25-Staff-123.

The Society of Energy Professionals Interrogatory # 3

Issue:

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

Reference:

B1-01-01 Section 1.5 Page: 1-2
"Productivity and Continuous Improvement" pp1-2 Table 17 "Detailed Productivity Savings Forecast"

Interrogatory:

a) Please update the referenced table 17 to include annual actuals for 2014-2016 and the 2017 forecast.

b) Please update the referenced table 17 updated in part a. above to include the additional capital productivity savings as provided in Exhibit Q1-1-1 pp7 Table 5 "Changes to Capital Forecast".

c) Please update the referenced table 17 as revised in part b. above to provide the OM&A and capex split of the Total Corporate Common productivity savings. If necessary, allocate these productivity savings between OM&A and capex. Also, provide the total OM&A savings and total capex savings for each year.

Response:

a) The productivity plan was established in late 2015 with forward looking initiatives. Hydro One has updated the 2016 actuals and 2017 forecast below.

				Updated Savings						
	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	2016 Actual	2017 Forecast	2018	2019	2020	2021	2022
Capital	Move to Mobile	Move to Mobile (Field Force)	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Pole Replacement, Field Meter Service, Component Replacement*	$ -	$ 14.9	$ 10.3	$ 10.5	$ 10.7	$ 10.7	$ 10.7
Capital	Procurement	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 1.11	$ 11.8	$ 12.7	$ 13.2	$ 17.0	$ 16.7	$ 18.6
Capital	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*		-	$ -	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Capital	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*		$ 0.5	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Capital	Telematics	Telematics	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ -	$ 3.95	$ 13.4	$ 10.1	$ 9.8	$ 9.6	$ 9.3
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 0.62	$ 0.64	$ 1.8	$ 2.6	$ 3.2	$ 4.1	$ 4.8
OM&A	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 2.53	$ 3.05	$ 7.4	$ 8.3	$ 11.5	$ 11.5	$ 11.5
OM&A	Information Technology	Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.25	$ 0.33	$ 0.9	$ 1.0	$ 0.9	$ 0.9	$ 0.9
OM&A	Information Technology	Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.63	$ 0.47	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7
OM&A	Move to Mobile	Move to Mobile (Clerical)	FTE Reduction *Reflects expected reduction in 29 back office support staff by 2020*	$ -	$ -	$ 2.7	$ 2.8	$ 2.9	$ 2.9	$ 2.9
OM&A	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 5.40	$ 11.90	$ 7.6	$ 7.8	$ 7.9	$ 8.1	$ 8.2
OM&A	Operations	Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ -	$ 0.06	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8
OM&A	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls*	$ 2.26	$ 6.30	$ 2.8	$ 4.1	$ 5.9	$ 6.9	$ 7.9
OM&A	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ -	$ 0.3	$ 0.3	$ 0.4	$ 0.4	$ 0.4	$ 0.4
OM&A	Operations	Engineering Work Team Migration	FTE Reduction *A reduction in support staff that was utilizing the legacy software*		$ 0.93	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
OM&A	Operations	Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 2.42	$ 1.50	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5
OM&A	Procurement	Procurement	IT Software Cost Reduction *Reflects expected and negotiated savings*	$ 0.93	$ 1.23	$ 0.9	$ 1.7	$ 2.6	$ 2.6	$ 2.6
OM&A	Telematics	Telematics	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ -	$ 1.07	$ 0.8	$ 0.8	$ 1.4	$ 1.3	$ 2.2
CCC	Administrative	Corporate Common Head Count Reductions	FTE Reduction *Identified headcount reductions by position in Corporate Common*	$ 1.30	$ 1.04	$ 1.7	$ 1.9	$ 1.9	$ 1.9	$ 1.9
CCC	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 0.11	$ 1.78	$ 2.3	$ 2.3	$ 2.3	$ 2.3	$ 2.3
Total	Capital			$ 1.11	$ 31.15	$ 36.4	$ 34.2	$ 37.8	$ 37.3	$ 39.0
Total	OM&A			$ 15.04	$ 27.77	$ 29.4	$ 33.7	$ 40.9	$ 42.9	$ 45.5
Total	Corporate Common			$ 1.41	$ 2.82	$ 4.0	$ 4.2	$ 4.2	$ 4.2	$ 4.2

b) Please refer to Exhibit I-25-Staff-123 for the updated plan

c) Please refer to Exhibit I-8-Staff-018, response a).

Witness: LOPEZ Chris

OEB Staff Interrogatory # 158

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2573
(5.4.5.2) Attachments: Material Investments, ISD: SA-02 Metering Infrastructure Sustainment Program

Interrogatory:

*"**Costs:***

The costs for this program are projected based on these historic labour costs, material unit costs, and future anticipated needs. The factors which affect the costs in this investment are the following:

- *The cost of material and term of procurement contracts;*
- *The volume and types of meters and network devices requiring replacement; and*
- *The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.*

Controllable costs have been optimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials."

a) What is the division in costs of equipment versus labour?

b) Do these costs include any cost savings/productivity gains (e.g. procurement savings)? If so, please describe in detail.

Response:

a) The division is 46% equipment and 54% Labour.

b) No, however Hydro One entered into a contract with the meter vendor for supply of meters to provide a predictable and controllable cost structure.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 159

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2611 and 2617
(5.4.5.2) Attachments: Material Investments, ISD: SR-06 Distribution Station Refurbishment
EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –S-07 Station Refurbishment

Interrogatory:

SR-06 Distribution Station Refurbishment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	148.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Capacity Upgrade		

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	16.2	31.8	36.4	37.1	37.8	159.3
Less Removals	1.1	2.2	2.5	2.6	2.6	11.1
Gross Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**

**Includes Overhead at current rates.*

a) Please explain how this program is related to and coordinated with SR-01 and SR-04.

b) Please confirm that the proposed distribution station refurbishment plan calls for an average of 15 distribution stations to be refurbished each year over the 5-year test period, for a total program spending of $148.1 million, even though this investment plan is identified as having medium priority.
   i. Please explain why so much investment is being planned for a medium priority program.

c) Is it possible for Hydro One to reduce the investment plan by refurbishing only the highest risk distribution stations, or by reducing the plan from 15 distribution stations per year to 10 stations per year over the 5-year test period?

d) In EB-2013-0416, the investment S-07 Station Refurbishment provided several stations planned for refurbishment. Several of these stations are repeated in this application, in investment SR-06 Distribution Station Refurbishment. Please provide an explanation why these stations were not completed as planned in the last application under investment S-07.

e) Please provide a list of stations refurbished in the last three years. The list should include the station name, estimated cost of the station refurbishment, actual cost of the station refurbishment, and an explanation for material variance between estimated and actual cost.

f) For each station refurbishment project provided for the last three year please provide the scope of work to be completed at each station.

Response:

a) All three programs address the replacement of station components but under different conditions, as summarized below. These three programs are coordinated during the investment planning process to ensure work is integrated and there is no duplication.

- SR-01 Distribution Stations Demand Capital program replaces major station components on an unplanned/demand basis where the component is failing or has already failed.
- SR-04 Distribution Station Component Replacement program replaces minor station components (switches, structures, station service, fencing and ground grid) on a planned basis based on the condition of the asset.
- SR-06 Distribution Station Refurbishment program replaces or refurbishes major station components (transformers, reclosers, high voltage and low voltage structures) on a planned basis based on the condition of the station assets.

b) Confirmed. As described in ISD SR-06 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8; the distribution station refurbishment plan is a medium priority investment and calls for refurbishment of approximately 15 stations per year for a total cost of $148.1 million.

The program is considered a medium priority program in context to all the investments in the proposed plan based on the risk assessment and investment optimization of the Investment

Planning Process described in Exhibit B1, Tab 1, Schedule 1, Section 2.1.4.2. The funding level proposed for this program is based on maintaining the number of stations that are classified as high risk (based on condition assessments) at a stable level.

c) It is possible for Hydro One to target only 10 stations per year for refurbishment and refurbish the highest risk stations first. If 10 station refurbishments were completed per year the average age of the transformer fleet would increase and it is expected that the overall condition of the fleet would deteriorate. As the condition of the fleet deteriorates, it is expected that there would be a corresponding increase in transformer failures which would lead to increased costs in other investments such as: SR-01, SR-02 and SR-03. It is also expected that this will result in higher investment levels beyond the five year term which would be funded by future ratepayers.

d) Station refurbishment projects from EB-2013-0416 S-07 that appear in SR-06 of this application were deferred due to a reprioritization of investments. Please refer to interrogatory response Exhibit I-23-Staff-84 part (c) for further details on the reprioritization process.

e) & f) A list of stations refurbished in the last three years is provided in the table below detailing the costs and scope of work at each station. A variance explanation has been provided for all the material variances (>20%). The major causes for variance from the unit cost are that the unit cost did not consider the following items: dual transformer stations, additional requirements for 115kV connected stations, spill containment, significant expansion of existing station, and installing new HV and LV structures.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wilsonville DS	2014	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford DS #2	2014	2.4	2.8	0.4		Install new 7.5MVA transformer. Expand existing site, install new HV/LV and exit structures, reclosers, fence, and ground grid.
Brighton DS #2	2014	2.4	2.3	-0.1		Replace transformer with spare 7.5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Cache Bay DS	2014	2.4	2.3	-0.1		Install new 7.5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Oxley DS	2014	2.4	2.3	-0.1		Install new 5MVA transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land.
Brockville Parkdale DS	2014	1.9	2.2	0.3		Install iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Huntsville RS	2014	2.4	2.2	-0.2		Install new 25MVA regulator transformer with spill containment. Install new 4 pole regulating station structure, fence, ground grid
Berkeley DS	2014	1.0	0.5	-0.5	Decrease as unit cost did not consider use of a non-ULTC transformer.	Replace existing transformer (3 single phase units) with a new 5MVA 3 phase bank.
Currie DS	2014	2.4	1.7	-0.7	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid, LV and exit structures. Keep existing HV structure.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Bothwell DS #2	2014	2.4	0.9	-1.5	Decrease as unit cost did not consider the use of a spare transformer.	Replace transformer with a spare 5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Crow River DS	2015	2.4	6.4	4.0	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA new transformers. Expand existing site, install new fence, yard lighting, and ground grid. Modify existing LV structures to increase clearances. Install new revenue metering with transfer scheme.
Red Lake DS	2015	2.4	6.0	3.6	Increase as unit cost did not consider spill containment for 4 transformers.	Refurbish existing transformers. Install spill containment around 4 existing transformers. Expand existing site, install new LV exit structures, reclosers, fence and ground grid.
Abitibi Canyon DS	2015	2.4	5.4	3.0	Increase as unit cost did not consider dual transformer stations.	Refurbish two existing 5MVA transformers and re-install on new concrete pads. Install new LV MUS exit structures, reclosers, station fence, and ground grid. Keep existing HV/LV structures. Soil remediation as required
Kirkland Lake Woods DS	2015	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new LV and exit structures.	Install spare 5MVA transformer and switchgear Expand existing site, install new LV structure, exit structure, reclosers, fence, and ground grid. Keep HV structure.
Trenton Bay DS	2015	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site with new HV and LV structures and demolition of existing building.	Install new 7.5MVA transformer with ULTC. Install new HV and LV structures, reclosers, ground grid and fence. Acquire new land. Demolish building that contained the equipment.
Barwick DS	2015	2.4	4.5	2.1	Increase as unit cost did not consider dual transformer stations.	Install two 6MVA repaired transformers. Expand existing site, install new reclosers, fence and ground grid. Keep existing HV and LV structures.

Witness: GARZOUZI Lyla

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Nestor Falls DS	2015	2.4	3.5	1.1	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground. Incorporate revenue metering to new design including at MUS facilities.
Kemble DS	2015	2.4	3.0	0.6	Increase as unit cost did not consider expansion of existing site and dual transformer stations.	Install two new 7.5MVA transformers. Expand existing site, install new LV exit structures, reclosers, fence, and ground grid. Keep existing HV and LV structures.
Longlac West DS	2015	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site.	Install new 10MVA transformer and spare regulator transformer with new 4 pole structure. Expand existing site, install new recloser, fence. Keep existing HV and LV structures.
Bobcaygeon Duke DS	2015	2.4	3.3	0.9	Increase as unit cost did not consider reengineering of structure to mount new components and establishing proper grounding in bedrock.	Install new 7.5MVA transformer. Replace fuses with reclosers. Keep existing HV and LV structures.
Campbellford Industrial DS	2015	1.9	2.3	0.4	Costs higher than anticipated as this was part of iMDS pilot program.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Merlin DS	2015	2.4	2.8	0.4		Install new 5MVA transformer with ULTC. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Tilbury Peltier DS	2015	2.4	2.6	0.2		Install new 5MVA transformer. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford Thompson DS	2015	1.9	2.4	0.5	Costs higher than anticipated as project was part of iMDS pilot.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Lindsay Eastview DS	2015	1.9	2.3	0.4		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Maxville George DS	2015	2.4	2.3	-0.1		Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Aguasabon DS	2015	1.0	0.9	-0.1		Replace existing hot spare transformer with new 7.5MVA unit.
St.Williams DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence and ground grid.
Geraldton South DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Bolsover DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer. Install new reclosers and ground grid. Keep existing HV and LV structures.
Meaford Louisa DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Larder Lake DS	2015	2.4	2.5	0.1		Replace transformer with a spare 5MVA unit. Replace fuses with reclosers. Install new ground grid. Keep existing HV and LV structures.
Essex DS	2015	2.4	2.0	-0.4		Install new 5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Owen Sound 3rd Ave DS	2015	1.9	1.8	-0.1		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Trenton Frankford DS	2015	1.9	1.8	-0.1		Install new iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence.
Havelock Industrial DS	2015	1.9	1.7	-0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Highgate DS	2015	2.4	1.6	-0.8	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 5MVA transformers. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV / LV structures.
Otonabee DS	2015	2.4	1.5	-0.9	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 5MVA transformer. Install new reclosers and ground grid. Keep existing HV/ LV structures.
Kenogami DS	2015	2.4	1.7	-0.7	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 10MVA transformer and reclosers. Keep existing HV and LV structures.
Lindsay Eglinton DS	2016	2.4	7.4	5.0	Increase as unit cost did not consider spill containment, soil remediation and landscaping required to obtain approval from municipality.	Install new 5MVA transformer with spill containment. Install new LV structure, reclosers, and ground grid. Keep HV structure. Complete soil remediation and landscaping.
Deep River DS	2016	2.4	5.1	2.7	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA transformers with ULTC. Install new reclosers, fence and ground grid. Keep existing HV and LV structures.
Shining Tree DS	2016	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new LV structures, reclosers, fence and ground grid. Keep existing HV structures. Reconfigure existing metering to accommodate new structure and MUS facilities.
Little Current DS	2016	2.4	3.8	1.4	Increase as unit cost did not consider development of new land, new HV and LV structures.	Install new 7.5MVA transformer with ULTC, Install new HV and LV structures, reclosers, ground grid, fence, drainage. Acquire new land.

Witness: GARZOUZI Lyla

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wyoming Churchill DS	2016	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Perrault Falls DS	2016	2.4	3.9	1.5	Increase as unit cost did not consider expansion of existing site, new HV and LV structures and connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV/ LV structures, reclosers, fence, ground grid, new revenue metering to meter at main structure and MUS facilities.
Fiddlers Green DS	2016	2.4	3.1	0.7	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Brockville Water DS	2016	2.4	3.0	0.6	Increase as unit cost did not consider non-standard stations with minimal space requiring unique design.	Install new 7.5MVA pad mount transformer. Remove existing switchgear and install pad mount reclosers.
Appin DS	2016	2.4	2.8	0.4		Install new 5MVA pad mount transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land. Remove approximately 1km of off road 28kV circuit and replace with 600m of on road circuit.
Abbey DS	2016	2.4	2.5	0.1		Install new 5MVA transformer with ULTC. Install new transformer pad, reclosers, ground grid and fence. Keep existing HV/LV structures.
Post Creek DS	2016	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.

OEB Staff Interrogatory # 160

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2658

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

Interrogatory:

"Alternative 2: Remote Disconnections/Reconnections (Recommended)

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

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

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

Response:

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

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

OEB Staff Interrogatory # 161

Issue:

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

Reference:

Office of Auditor General of Ontario – Annual Report 2015 (Rec. 13)

Interrogatory:

The Auditor General's report recommended the following:

> *"To ensure that its capital sustainment and maintenance expenditures on the distribution system are cost effective and produce more immediate improvements to the reliability of the distribution system, Hydro One should:*
>
> - *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"*

Does Hydro One consider the potential reduction in future OM&A when building a business case for capital expenditure? If not, why? If so, please compile the total expected OM&A savings by capital investment.

Response:

Yes, where future OM&A costs are impacted by a capital expenditure they are considered when building the capital investment plan. Please refer to interrogatory response Exhibit I-25-Staff-123 for the "ISD Total" OM&A productivity savings Hydro One has quantified for the capital investments listed in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Vulnerable Energy Consumers Coalition Interrogatory # 23

Issue:

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

Reference:

A-03-01-01
A-03-01-02
Q-01-01-01

Interrogatory:

Aside from matters arising from the inclusion 2023 (and completion of 2017) what are the material differences between the 2017-2012 and the 2018-2023 Distribution Business Plans?
Has Hydro One updated the Consolidated Business Plan? If yes please file this plan.

Response:

Please refer to Exhibit Q, Tab 1, Schedule 1 for the material differences in between the 2017-2022 and the 2018-2023 Distribution Business Plans. Attached is the updated Consolidated Business Plan, redacted for content on Hydro One's unregulated business.

Consolidated Business Plan 2018-2023

December 8, 2017

Strategy

Hydro One is a purpose-led and values-driven company. Earlier in 2017, Hydro One launched the values that are integral to the company and to its communities. Those values include:

- Safety comes first;
- Stand for people;
- Empowered to act;
- Optimism charges us; and
- Win as one.

Hydro One's strategic vision and business goals are consistent with, and included in, the business plans for Hydro One. This strategy will involve executing a number of strategic initiatives as follows:

- Optimization of the Core;
- Innovation in the Core;
- Diversification by Entering Commercial Businesses; and
- Building Scale and Diversifying the Business through M&A.

Optimization and Innovation in the Core

For the Ontario-based, rate-regulated transmission and distribution businesses Hydro One is transforming to achieve its vision of becoming a best-in-class, customer-centric commercial entity, with a culture of operational excellence and continuous improvement. To achieve this vision, Hydro One will execute on its strategy to transmit and distribute electricity safely and reliably in a manner that produces the greatest value for customers. Hydro One seeks to be excellent in every facet of its operations, to the benefit of its customers, employees and shareholders.

Hydro One's commercial orientation means that the company will be focused on customers, demonstrate corporate accountability for performance outcomes, and drive company-wide efficiency and productivity. Understanding customers' needs and preferences and delivering system outcomes that are valued by customers are critical to Hydro One's future success. Hydro One will excel at managing relationships with key stakeholders including customers, Indigenous communities, employees, governments and regulators.

Innovation will become a focus for the company and Hydro One plans to invest in innovation to modernize the transmission and distribution grids, improving reliability and efficiencies as well as building a platform for connecting distributed energy resources.

Diversification by Entering Commercial Businesses

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Customer Expectations

Hydro One is a customer centric commercial entity that provides service to its customers that meets their needs and preferences while ensuring that the system continues to deliver safe, reliable energy. This customer focus requires that Hydro One have a strong understanding of customer's expectations for the Company. These expectations evolve and change over time which is why it is necessary for Hydro One to conduct formal customer engagement activities at regular intervals to ensure that Hydro One's business objectives and investment planning outcomes are appropriate, supplementing ongoing customer feedback and interaction. It also allows the Company to have focused discussions on system investment plans prior to rate filings.

Hydro One's Transmission and Distribution businesses have very different classes of customers that were segmented and engaged using a variety of consultation methods including but not limited to one-on-one sessions, online surveys and focus groups. The results of the engagement showed contrasting priorities between the two businesses. Transmission customers' top priority was reliability maintenance or improvement and they were willing to accept a small rate increase to achieve that outcome. In addition, energy quality was a significant factor for several sophisticated energy users. Distribution customers consistently prioritized low cost and wanted Hydro One to limit increases in rates. These preferences have guided the development of the investment plan for each business, with Transmission focusing on investments that will improve reliability and quality, and the Distribution investment plan designed to leverage productivity and keep rate impact low while still seeking some improvements in reliability. Both plans have benefited from a significant focus on analytics and cost efficiency plans to continue to reduce costs before asking customers for increases in rates.

More details on the methodology for customer engagement and detailed results of the findings can be found in the business plans for Transmission and Distribution.

Common Corporate Costs

Hydro One utilizes a centralized shared services model to deliver its common services to its Transmission and Distribution businesses and to its affiliated companies. Each business and affiliate pays their share of these costs based on a cost allocation methodology developed by Black and Veatch Corporation and approved by the OEB which utilizes a breakdown of activities and drivers based on cost causality principles.

As shown below, the majority of costs are allocated to the Transmission and Distribution businesses. A significant portion of these costs get capitalized based on the size of the Company's capital work program relative to OM&A. The balance of 10.7% gets allocated Telecom, Remotes and shareholders. The OEB took issue with the amount of corporate management costs included for recovery from rate payers. The OEB considered some significant costs to be associated with transforming the company from a government owned regulated utility business to a growth oriented publicly traded company. Following OEB input, an adjustment has been made to move additional business transformation costs out of rate recovered business units.

Total Corporate Common Costs 2017 to 2023

Corporate Common Cost $M	2017F	2018	2019	2020	2021	2022	2023	CAGR
Corporate Management	$ 12	$ 14	$ 14	$ 14	$ 15	$ 15	$ 15	3.9%
General Counsel & Regulatory Affairs	$ 35	$ 41	$ 39	$ 38	$ 38	$ 40	$ 41	2.6%
Operations	$ 113	$ 108	$ 108	$ 106	$ 107	$ 108	$ 108	-0.8%
Customer and Corporate Relations	$ 40	$ 43	$ 44	$ 45	$ 47	$ 47	$ 47	3.1%
Human Resources	$ 18	$ 22	$ 21	$ 21	$ 22	$ 22	$ 22	3.7%
Strategy	$ 13	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	-3.3%
Finance	$ 43	$ 48	$ 48	$ 49	$ 50	$ 50	$ 51	2.8%
Information Solutions Division	$ 21	$ 19	$ 19	$ 17	$ 18	$ 18	$ 18	-2.7%
Bad Debt	$ 18	$ 19	$ 19	$ 18	$ 18	$ 18	$ 18	-0.3%
Total	**$ 313**	**$ 323**	**$ 321**	**$ 320**	**$ 325**	**$ 329**	**$ 331**	**0.9%**

	OM&A	Capital
Transmission Portion	16.4%	30.3%
Distribution Portion	23.9%	18.8%
Other Allocated	10.7%	

Building Owners and Managers Association Toronto Interrogatory # 9

Issue:

Issue 27: Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

Reference:

A-02-02 Page: 1
This exhibit lists and cites where in evidence Hydro One's record of compliance with recent OEB directions.

Interrogatory:

Please provide a similar table listing government policy, directions and obligations either to Hydro One or to other agencies in the electricity sector that affect Hydro One's activities, citing the government direction, Hydro One's response and references to the evidence that confirm the direction has been follower.

Response:

There are no active government directives issued to Hydro One. Hydro One has not compiled a list of other electricity sector "policy, directions and obligations" that may affect Hydro One's activities. This is an extremely broad request with limited probative value.

Energy Probe Research Foundation Interrogatory # 52

Issue:

Issue 27: Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

Reference:

C1-01-04 Page: 18

Interrogatory:

What is Hydro One's approximate total investment in Smart Grid since EB-2009-0096?

a) What are the metrics that Hydro One uses to manage its annual investment in Smart Grid?

b) How does Hydro One track the effectiveness of its annual Smart Grid investment?

Response:

As of December 2017, Hydro One's approximate total investment was $57 million on Advanced Distribution System Project for 2015 - 2017. This investment has established the foundation for Hydro One's smart grid in the form of control systems, analytics systems and piloting of various smart grid devices to be deployed in the field.

a) To manage annual investments in Smart Grid, Hydro One uses a ratio of expected reliability gain to cost of the investment. Investments are prioritized based on their reliability impact, with investments with the highest ratio receiving priority.

b) Effectiveness of annual Smart Grid investments is tracked based on a three-year average baseline of reliability pre-investment and a three-year average reliability post-investment.

Ontario Sustainable Energy Association Interrogatory # 19

Issue:

Issue 27: Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

Reference:

B1-01-01 Section 3.5 Page: 5

Preamble: Hydro One sets out the government initiatives that have been put in place through the IESO to procure renewable energy for the province of Ontario.

Interrogatory:

a) Is Hydro One exploring renewable energy programs other than the government initiatives put in place to procure renewable energy for the province of Ontario? Please provide details.

Response:

Hydro One is not procuring renewable energy as the energy procurement responsibility lies on Independent Electricity System Operator (IESO). Hydro One facilitates the connection of renewable energy generation to the Hydro One distribution system and considers the use of distributed energy resources to support the needs of the distribution system.

Association of Major Power Consumers in Ontario Interrogatory # 9

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

B1-01-01 Section 1.2

Interrogatory:

1. Page 13: Please confirm the Regional Infrastructure Plan for Burlington to Nanticoke Regions was completed in Q1 2017 as scheduled. Please advise if any of the proposed Actions have been changed.

2. Page 22 Table 6: Please update Table 6 as required to reflect the most current projects, forecast cost and in-service dates for the projects.

3. Page 22 Table 6: Please identify the projects to be completed by Hydro One Transmission.

4. Page 22 Table 6: Please identify the projects with contributions from other parties.

Response:

1. Yes, the Regional Infrastructure Plan for Burlington to Nanticoke region was completed in Q1 2017 as scheduled. The proposed actions involving Hydro One Distribution have not changed.

2. No new regional planning projects have been proposed involving Hydro One Distribution. The project list in Table 6 remains the most current forecast status.

3. The projects to be completed by Hydro One Transmission are: ISD GP-25 (Leamington TS), ISD GP-26 (Hanmer TS) and ISD GP-27 (Enfield TS) as documented in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

4. Please refer to interrogatory response Exhibit I-28-SEC-51 for projects with contributions from other parties.

Building Owners and Managers Association Toronto Interrogatory # 10

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

B1-01-01 Section 1.2

Interrogatory:

Please provide a similar table to that of EB-2017-0049, Exhibit A, Table 2, Schedule 2 Page 1 of 2 demonstrating where and how the results of regional planning has be incorporated into its Distribution System Plan. Are any elements of any of the completed regional plans recommended to be implemented within the 5-year plan not included in the Distribution System Plan? If so, please indicate, why particularly given the choice of the DSP option.

Response:

The specific reference to EB-2017-0049 contained in the interrogatory does not reference a table demonstrating where and how the results of regional planning has been incorporated, so a similar table could not be replicated. However, Hydro One Distribution has provided the list of projects resulting from the regional planning process in Table 6 of Exhibit B1, Tab 1, Schedule 1, DSP Section 1.2.

All elements of the completed regional plans recommended to be implemented by Hydro One Distribution within the 2018 to 2022 period are included in the Distribution System Plan.

Building Owners and Managers Association Toronto Interrogatory # 24

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

A-03-01 Page: 26 Table 9

Interrogatory:

a) Why is the general plant forecast consistently substantially underestimated over the years 2015, 2016, and 2017? Please explain fully.

b) What have system renewal expenditures been to September 30, 2017, or the most recent date you have? What is the most current forecast for 2017 year end capex (the 252.2 on year end 2016 estimate)?

Response:

a) Please refer to Exhibit I-29-Staff-165 part (c).

b) The most recent 2017 year end system renewal expenditures will be provided once Hydro One's 2017 audited actuals become available. The current 2017 forecast for system renewal expenditures is provided in Table 54 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.2.

Building Owners and Managers Association Toronto Interrogatory # 25

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

A-03-01 Page: 27

Interrogatory:

a) What does life cycle optimization in investments mean?

b) Please explain the amount of spending to replace smart meters that are at the end of life in 2021. When were the meters to be replaced in 2021 and 2022 installed? What is the effective life that expected life, compared to other distributors' experience? What were the total meter replacement costs (2017, over what period of time?) What percentage of outstanding smart meters will be replaced?

Response:

a) For an explanation of life cycle optimization investments please refer to ISD SR-13 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

b) The spending to replace smart meters that are at the end of life is $1.4 million and $78.7 million for 2021 and 2022 respectively.

   The meters to be replaced in 2021 and 2022 were installed in 2006 and 2007 respectively.

   The expected service life is 15 years. Smart meters are a new technology and there is insufficient data to determine if the expected service life can be exceeded or to allow comparison with other distributors.

   The total meter replacement costs in 2017 were $9 million.

   The replacements planned for 2021 and 2022 represent 16.5% of the total smart meter population. Beyond this period, Hydro One is planning to replace the remaining smart meter population once their expected service life is reached.

Ontario Sustainable Energy Association Interrogatory # 20

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

B1-01-01 Section 3.5 Page: 1

Preamble: "Hydro One's asset strategy for distributed generation connections is to meet its distribution license requirements to connect generators that meet the principles set out in the Distribution System Code ("DSC"), and to perform Renewable Enabling Improvements (as defined in the DSC) to allow for the connection of DGs."

Reference: EB-2011-0118, letter of comment

Preamble: "From the launch of the FIT program to present there seems to have been a disconnect between senior levels of management and field offices. The simple reality is that the rate payers and developers have been advising field operations and anyone that would listen that there would be a crunch coming this summer with respect to getting connections completed, supplying equipment, ensuring inspectors are available, and ensuring disconnects/reconnects are carried out efficiently. Now, with the admission of short sighted planning, we are asked to provide further reprieve and exemption to service standards while in this area alone the community has millions of dollars invested in systems that await disconnect/reconnect. I see no clear reason to allow this exemption. More importantly, this serves as good reason to compel Hydro One to deploy the appropriate level of resources to service the demand. If exemption is provided, what relief is provided to the rate payer for whom an unacceptable period of time and lost revenue has passed waiting for disconnect/reconnect for which they have already paid required fees and charges under contract with Hydro One? The economic fairness of imposing further delay by the requested exemption has not been fully considered and should be denied."

Interrogatory:

a) Given that Hydro One's Public Policy Responsiveness includes: "Partner in the economic success of Ontario and sustainably manage our environmental footprint" and given that net metering is a customer facing issue, has Hydro One considered undertaking a proactive approach to distributed generation connections that:

i. Includes, but goes beyond, the Distribution System Code requirements, and

ii. Assists customers in the transition to net metering so that the costly problems associated with connections under the Feed in Tariff Program are avoided, and customers' transition is enabled?

Response:

i) Hydro One's DG technical interconnect requirements have enabled large amounts of DG, striking a balance between meeting customer needs and demands and maintaining the integrity of the power system. Hydro One is working towards developing new solutions that enable new distributed energy resource connections while minimizing customer connection costs. As reflected in ISD SS-07 (Advanced Distribution System) found in section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1), Hydro One is plans to establish a Distributed Energy Resource Management System as part of the Demand Response for Operations. The objective of this project is to run the system closer to its operating limits.

ii) Changes to the relevant regulation are under consideration by the Ministry and are expected to become effective later this year. As such, Hydro One believes the prudent approach is to understand the intent and scope of these revisions prior to initiating proactive activities. Hydro One has a specialized team of agents within the Customer Contact Centre that can help customers with their applications and answer questions.

The documents and support described in (i) continue to be available on Hydro One's website.

https://www.hydroone.com/business-services/generators/net-metering

School Energy Coalition Interrogatory # 51

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

B1-01-01 Section 1.2 Page: 7

Interrogatory:

With respect to the Regional Planning process:

a) Please provide a list of all Hydro One capital projects that are either driven by or an output of the regional planning process. For each, please provide a description, the regional plan it relates to, the total capital cost, and its in-service-date.

b) For any projects listed in part (a) that require a capital contribution from another local distribution company ("LDC"), please identify the projects, the amount of the capital contribution(s) Hydro One expects to receive and from whom, and the basis for the allocation of costs between Hydro One and the LDCs making the contribution.

c) Please provide a list of all capital contributions that Hydro One is making to Hydro One transmission, another transmitter, or an LDC.

d) For each project provided in response to part (c), please identify i) the project, ii) the regional plan it relates to, iii) the total capital cost, iv) the amount of the capital contribution, v) the projects' in-service date, vi) the date for rate purposes that Hydro One is seeking to add the capital contribution to rate base, and vii) the basis for the allocation of costs between Hydro One and any other entity.

e) Please discuss how the response to part (b) and (c) would differ if the Board approved as proposed amendments to the Transmission System Code and Distribution System Code as set out in the Notice of Proposal to Amend A Code, dated September 21 2017 (EB-2016-0003).

Response:

a) Please refer to Table 6 in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.2. All projects in the table are Hydro One distribution projects, with the exception of projects GP-25, GP-26 and

GP-27, which are transmission projects towards which Hydro One Distribution must make a capital contribution.

The Project Cost included in the table for all distribution projects is the total capital cost, with the exception of project LG-14, Leamington TS Feeder Development, which has a total capital cost of $16.5 million.

b) Of the distribution projects referenced in part (a), Hydro One expects to receive capital contribution from other LDCs only for the Leamington TS Feeder Development project. For this filing, Hydro One assumed that we would receive approximately $6 million in capital contribution from benefitting embedded distributors and large customers, based on the Hydro One proposed methodology described in its application for leave to construct a new transmission line and facilities in the Windsor-Essex Region (EB-2013-0421).

c), d) The projects noted in Table 6 in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.2 for which Hydro One is making a capital contribution are listed below with requested information. The in-service date is also the date for rate purposes that Hydro One is seeking to add the capital contribution to rate base.

ID	Project Name	Region	In-Service Date	Total Project Capital Cost[1]	Gross Capital Contribution[2]	Basis of Cost Allocation
ISD GP-27	Enfield TS - Capital contribution	GTA East	05/2019	$33.1M	$5.0M	Project costs allocated by transmitter.
ISD GP-26	Hanmer TS Capital Contribution	Sudbury/ Algoma	02/2019	$30.0M	$5.4M	Project costs allocated by transmitter.
ISD GP-25	Leamington TS Capital Contribution	Windsor-Essex	04/2018	$72.3M	$20.6M	Project costs allocated based on the methodology proposed in Hydro One's Section 92 application for a new transmission line and facilities in Windsor-Essex Region (EB-2013-0421).

[1] Total capital cost of transmission projects taken from Hydro One Transmission rate application EB-2016-0160
[2] All Hydro One Distribution capital contributions are being made to Hydro One Transmission. Gross capital contribution amount is total amount paid from Hydro One Distribution to Hydro One Transmission.

e) Based on Hydro One Distribution's current understanding of the proposed amendments to the Transmission System Code, Hydro One anticipates that there would likely be no change to the capital contribution amounts for the Enfield TS and Hanmer TS investments identified in the response to part (c); however there would be significant regulatory uncertainty in the case of Leamington TS due to the adjudicative process contemplated in Section 6.3.18B of the proposed amendments to the Transmission System Code.

The predominant change to the Distribution System Code is the proposed requirement that costs associated with upstream transmission investments be allocated to large distribution-connected beneficiaries of those investments (that is, embedded distributors and large distribution-connected consumers equal to or greater than 3 MW). Accordingly, the "Gross Capital Contribution" stated above would be allocated between Hydro One Distribution and these parties. As Hydro One had initially assumed a large customer threshold of 500 kW for the SECTR (Leamington TS) filing, use of the proposed 3 MW threshold would be expected to reduce the number of customers making a capital contribution to Hydro One Distribution, resulting in a greater proportion of the "Gross Capital Contribution" being funded by Hydro One Distribution. At this time, however, the consultation on this policy question is underway and the customer threshold issue, as well as the other proposed changes are not yet resolved. Given this uncertainty, Hydro One cannot comment further at this time on the impacts of the proposed amendments on the above investments.

OEB Staff Interrogatory # 162

Issue:
Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:
B1-01-01 Section 1.2 Page: 48
(5.2.2) Coordinated Planning with Third Parties - Regional Planning, Section 1.2.3 Status of Regional Planning Activities

Interrogatory:
"The initial cycle of regional planning has been completed, or deemed completed, for 12 out of the 19 regions that Hydro One belongs to, and the regional planning activities are in progress on the remaining 7 regions."

Please identify all project expenditures included in this filing related to expected findings from the 7 regions where planning activities were still in progress as of the date of filing?

Response:
All projects included in this filing associated with expected findings from regional planning activities that were still in progress as of the date of the filing are identified in the table below.

Project ID	Project Name	In-Service Date	Project Plan	Project Cost	Region
ISD SS-02 Project LG-28	Dundas TS #2 Feeders	10/2020	Construct 2 x 44 kV feeder positions & 10 km of new line	$6.7M	Burlington to Nanticoke
ISD SS-02 Project LG-24	Muskoka TS M5 x M1 Feeder Tie	12/2019	Build 14 km new 44 kV line	$5.3M	Southern Georgian Bay /Muskoka
ISD SS-02 Project LG-26	Barrie TS– Construct new Feeders	12/2020	Build 8km new 2-circuit 44 kV line	$2.6M	Southern Georgian Bay /Muskoka

The above projects are a subset of the Hydro One Distribution projects identified in Table 6 of Exhibit B1, Tab 1, Schedule 1, DSP Section 1.2 associated with regional planning activities.

Witness: GARZOUZI Lyla

Association of Major Power Consumers in Ontario Interrogatory # 27

Issue:

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

Reference:

B1-01-01 Section 2.4

Interrogatory:

a) Please provide the proposed investment levels for Plan A, Plan B, Plan C and Plan B Modified compared to the average investment level for the years 2014 to 2017.

b) For each of the following assets used in the Investment Plan Scenarios, please provide the asset unit replacement levels for the years 2012 to 2017 and forecast for the years 2018 to 2022: poles, stations, other line equipment, and vegetation.

Response:

a) The following tables detail the capital spending levels for Plan A, Plan B, Plan B Modified and Plan C compared to the average of 2014-2016 actuals and 2017 forecast. Note: Plan C was not fully developed into programs and projects as the option as a whole was deemed not viable. (Please refer to part c) of Exhibit I-35-BOMA-31 and section 1.1 of the DSP, pages 17-19.)

	2014-2017 ($M - Average)	2018 ($M)	2019 ($M)	2020 ($M)	2021 ($M)	2022 ($M)
Plan A	663.4	783.5	818.6	749.6	759.6	863.6
Plan B		685.0	742.4	713.3	730.1	821.5
Plan B modified		633.9	756.8	719.0	740.7	827.2
Plan C		603.9	644.3	605.6	622.8	716.0

b) Historical volumes are found in Exhibit I-24-AMPCO-25, Attachment 1. Forecast volumes for each plan level are as follows:

Pole Replacement Program Volumes	2018	2019	2020	2021	2022
Plan A	14,200	15,200	16,000	16,000	16,000

Plan B	12,440	14,300	16,000	16,000	16,000
Plan C	9,000	9,000	9,000	9,000	9,000
Plan B-Mod	9,600	14,300	16,000	16,123	16,128

Stations Refurbishment Volumes	**2018**	**2019**	**2020**	**2021**	**2022**
Plan A	31	31	31	31	31
Plan B	20	20	20	20	20
Plan C	13	13	13	14	14
Plan B-Mod	8	15	15	17	18

Length of ROW Managed	**2018**	**2019**	**2020**	**2021**	**2022**
Plan A	34,666 km	34,666 km	34,666 km	34,666 km	34,666 km
Plan B	34,666 km	34,666 km	34,666 km	34,666 km	34,666 km
Plan C	N/A	N/A	N/A	N/A	N/A
Plan B-Mod	34,666 km	34,666 km	34,666 km	34,666 km	34,666 km

Note: Total line component volumes are not available, as they are dissimilar units replaced as part of both individual programs and as part of refurbishment projects.

Association of Major Power Consumers in Ontario Interrogatory # 28

Issue:

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

Reference:

B1-01-01 Section 2.4

Interrogatory:

a) Please complete the following Tables:

Response:

a) Hydro One is only able to report customer interruptions to the level of detail provided below.

The 2017 data is not available in the requested categories as it has not yet been classified using the methodology that was applied to the 2012-2016 data provided below.

Asset	2012 Contribution to SAIDI (hrs)	2013 Contribution to SAIDI (hrs)	2014 Contribution to SAIDI (hrs)	2015 Contribution to SAIDI (hrs)	2016 Contribution to SAIDI (hrs)	2017 Contribution to SAIDI (hrs)
Poles	0.3	0.3	0.4	0.8	0.4	
Distribution Stations	0.1	0.2	0.2	0.2	0.1	
Other Line Components	1.3	1.4	2.0	1.6	1.4	
Tree Contacts	2.2	1.9	2.0	2.2	3.0	

	2012 Contribution to SAIFI	2013 Contribution to SAIFI	2014 Contribution to SAIFI	2015 Contribution to SAIFI	2016 Contribution to SAIFI	2017 Contribution to SAIFI
Poles	0.1	0.1	0.1	0.1	0.1	
Distribution Stations	0.05	0.04	0.06	0.08	0.05	
Other Line Components	0.5	0.5	0.6	0.5	0.5	
Tree Contacts	0.5	0.4	0.5	0.5	0.6	

	2012 #outages/year (x1000)	2013 #outages/year (x1000)	2014 #outages/year (x1000)	2015 #outages/year (x1000)	2016 #outages/year (x1000)	2017 #outages/year (x1000)
Poles	0.2	0.3	0.3	0.4	0.4	
Distribution Stations	0.06	0.08	0.09	0.10	0.08	
Other Line Components	7.0	6.9	8.0	7.7	7.2	
Tree Contacts	7.0	5.8	6.5	6.9	7.4	

Association of Major Power Consumers in Ontario Interrogatory # 29

Issue:

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

Reference:

B1-01-01 Section 2.4

Interrogatory:

a) Page 3 line 15: As an example, please provide the calculation that underpins the estimated reduction in forced outages to 303 instances per years and SAIDI and SAIFI impacts from wood poles improving by 12% under Plan A.

Response:

a) Please refer to Exhibit I-29-Staff-164, part b).

Association of Major Power Consumers in Ontario Interrogatory # 30

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

Reference:
B1-01-01 Section 2.4

Interrogatory:
a) Page 5 line 15: Please provide the starting point level of work on medium or low priority rights-of-way maintenance in km/yr that is being reduced by 1,000 km/yr.

Response:
a) The vegetation management program originally filed, and referenced in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.4 has been replaced by the new strategy outlined in Exhibit Q, Tab 1, Schedule 1. Under this new strategy, all rights-of-way will now be managed using a defect-based approach with a three year maintenance cycle that addresses approximately 34,666 kilometers annually.

Association of Major Power Consumers in Ontario Interrogatory # 31

Issue:

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

Reference:

B1-01-01 Section 2.4 Page: 6 - Table 52

Interrogatory:

a) Please provide a breakdown of the sub-equipment components that are included in the Failure Rate/Impact for Stations.

Stations Sub-Equipment Categories	Contribution to Stations (Outages/year) (%)	Contribution to Stations SAIDI (%)	Contribution to Stations SAIFI (%)

b) Please confirm the Distribution Stations sub-components included in the SAIDI and SAIFI projections for investment plan scenarios.

c) Please provide a breakdown of the sub-equipment components that are included in the Failure Rate/Impact for Other Line Components.

Other Line Components	Contribution to Other Line Components (Outages/year) (%)	Contribution to Other Line Components SAIDI (%)	Contribution to Other Line Components SAIFI (%)

d) Please confirm the Other Line Components sub-components included in the SAIDI and SAIFI projections for investment plan scenarios.

Response:

a) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

b) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

c) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

d) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

Building Owners and Managers Association Toronto Interrogatory # 115

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

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 137

Interrogatory:
What is the detailed breakdown of capex? Why is the information not provided to customers?

Response:
The proposed capital expenditures are explained in detail in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.0 (5.4) Capital Expenditure Plan. Please refer to Exhibit I-23-Staff-079 for information on the different scenarios used during customer engagement.

Building Owners and Managers Association Toronto Interrogatory # 125

Issue:

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

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1; DSP 2.6 Page 18

Interrogatory:

a) Please demonstrate where in the investment plan the recommendation of the pole replacement and station and station refurbishment benchmarking studies are to be found.

b) Please provide copies of customer satisfaction surveys (Q&As) that have been done over the last three years.

Response:

a) B1-01-01 DSP 1.6.3 describes how the plan reflects the benchmarking recommendations.

b) Hydro One is unable to identify the specific scope of customer satisfaction surveys that are being sought in this interrogatory. Hydro One notes that it conducts many different types of customer satisfaction surveys of different customer groups. Hydro One has provided the results of some recent customer satisfaction surveys in responses to Exhibit I-16-BOMA-68 and Exhibit I-17-CCC-19.

Canadian Manufacturers & Exporters Interrogatory # 14

Issue:

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

Reference:

B1-01-01 Section 3.6 Page: 1 Table 63

Interrogatory:

a) In Table 63, the columns for 2013 and 2014 only show planned values. Footnote one explains that they were IRM years and don't have Board-approved capital expenditure figures. Does Hydro One have any data on actuals for those years? If so, could Hydro One please update the table with those values.

Response:

There was a typographical error in the 2013 and 2014 headers, figures reflect actuals. "Plan" should be replaced with "Actual".

Canadian Manufacturers & Exporters Interrogatory # 16

Issue:

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

Reference:

ISD: SR-05 Page 2 of 5

Interrogatory:

Hydro One states: "These new reclosers are designed for up to 10,000 reclose operations with minimal maintenance. This will reduce the maintenance required compared to oil filled hydraulic type reclosers which are only designed with a threshold of 58 to 272 reclose operations before a maintenance cycle is required.

a) What is the terminal number of reclose operations that the older reclosers could complete even with regular maintenance?

b) What is the terminal number of reclose operations that the new reclosers can complete with proper maintenance?

Response:

a) There is no terminal number of reclose operations used for older oil filled hydraulic reclosers. The number of reclose operations is only used to trigger when maintenance is required; as the components of these reclosers can all be replaced thereby resetting the operation count.

b) It is expected that these electronic reclosers can complete 10,000 operations with proper maintenance.

Canadian Manufacturers & Exporters Interrogatory # 17

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

Reference:
None

Interrogatory:
a) How will moving to a defect based management system affect Hydro One's ability to be benchmarked with other distributors who may not be using a defect based management system?

Response:
a) Moving to a defect based vegetation management strategy will not affect Hydro One's ability to be benchmarked. Core metrics, including cost per defect and cost per kilometre, will still be comparable. Outcome measures will still provide a good indicator of Hydro One's relative position with the benchmark peer group.

Canadian Manufacturers & Exporters Interrogatory # 18

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

Reference:
B1-01-01 Section 1.4 Page 9

Interrogatory:
Hydro One states: "This metric is directly impacted by the number of kilometres that were managed over many years and is not immediately impacted by the number of kilometres managed in the current or previous year. As a result this is a lagging indicator of the outcomes of the vegetation management program."

a) The Hydro One Vegetation Management Study states that outcomes under the defect management regime can be achieved in one-third of the time. Will this reduction in time help to ameliorate the lagging nature of the total vegetation caused interruptions measure? If not, why not?

Response:
a) Yes, by focusing on high criticality defects across one third the system each year, it is expected that the lag in reliability improvement should be considerably reduced.

Canadian Manufacturers & Exporters Interrogatory # 19

Issue:

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

Reference:

B1-01-01 Section 3.6 Page 3

Interrogatory:

Hydro One states: "System Service spending will remain within historical spending levels from 2018 to 2022. This represents a decrease as compared to previous budget amounts. This reflects a more realistic stance on the ability to complete the necessary work.

a) What about Hydro One's ability to complete necessary work was unrealistic?
b) What caused Hydro One to move away from its unrealistic work completion outlook?

Response:

a) The statement being referenced in B1-01-01 Section 3.6 page 3 was inaccurate; Hydro One's ability to complete the work was not unrealistic. The expenditures for System Service capital investments have been historically lower than the OEB approved funding amounts due to reprioritization to accommodate for unforeseen increases in other areas of capital spending. For a more detailed explanation see interrogatory response to Exhibit I-29-Staff-165 b).

b) See response to part a).

Canadian Manufacturers & Exporters Interrogatory # 20

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

Reference:
ISD SA-02 Page 2

Interrogatory:
a) What drives the changes over time in the number of metering devices that are replaced and how does Hydro One calculate the total forecast devices replaced?

Response:
Changes are a result of a variety of factors. The significant factors are product failure, regulatory requirements, technology obsolescence, end of service life, installation upgrades, vandalism and lost in fire.

The forecast is developed using historical replacement rates with consideration given to metering devices' remaining service life, technology obsolescence and upgrades to accommodate regulatory requirements (demand to interval) and new requirements.

Canadian Manufacturers & Exporters Interrogatory # 21

Issue:

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

Reference:

ISD SA-03 Page 1

Interrogatory:

Hydro One states: "some of these meters cannot communicate reliably with Hydro One's meter infrastructure network, resulting in manually reading of these meters at specific intervals and estimated billing for the customer."

a) Why can't some of the smart meters communicate with the network?

b) If the answer to a) is the carrier network's lack of capacity, why was the smart meter network solution chosen for those areas with weak network capacity?

c) Even with this investment, there will still be 96,564 meters without reliable communication, were any other alternatives that would have connected a larger number of meters considered before requiring another exemption from the OEB?

Response:

a) Meters are located in remote areas where third party telecom does not reach or are in areas that are isolated from the AMI communications network.

b) Based on extensive reviews of AMI network solutions, a single vendor solution was chosen to provide the greatest reach at the most economical cost. Reaching the remaining few remote meters of Hydro One's approximately 1.3 million meter population was cost prohibitive and not economically viable within the operating envelope approved by the OEB.

c) Hydro One believes it chose the most cost effective solution to reach the greatest number of customers at a reasonable cost. Hydro One believes there were no other alternatives at the time that would have reached more customers economically.

Canadian Manufacturers & Exporters Interrogatory # 22

Issue:

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

Reference:

B1-01-01 Section 1.1 Page 13 Table 2 and Page 14 of 23

Interrogatory:

Hydro One states: "System Renewal investment costs are projected to increase by an average of 12.3% annually during the forecast period. Storm damage restoration and trouble calls, pole replacements, and distribution station refurbishments (ISD SR-07, ISD SR-09, and ISD SR-06, respectively) make up the bulk of activities in this category."

a) If storm damages restoration and trouble calls are expected to remain stable, the pole replacement program and station refurbishment increase until 2020 and then level off, and smart meter replacement spending doesn't begin until 2022, please explain why system renewal spending is approximately $25.8 million higher in 2021 than it is in 2020.

b) Regarding the significant increase in projected spending in 2022 for the replacement of smart meters, does Hydro One plan on replacing smart meters in areas where they are unable to consistently send a signal?

c) If the answer to b) is yes, are the replacement meters expected to be able to send a signal consistently?

d) If the answer to b) is no, please provide the anticipated cost savings of not replacing the malfunctioning or under-performing smart meters with non-smart alternatives.

e) What are the drivers that determine the useful life of smart meters?

Response:

a) System Renewal expenditures are $25.8 million higher in 2021 versus 2020. This increase in expenditure is primarily due to increases in the following investments:

- $6.4 million increase in Distribution Lines PCB Equipment Replacement Program,

- $2.9 million increase in the Distribution Lines Sustainment Initiatives, and
- $6.4 million increase in Life Cycle Optimization and Operational Efficiency Projects.

The remainder of the increase can be attributed to the remaining System Renewal investments as shown on page 2 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.7.

b) Hydro One is planning to replace all meters that reach their expected end of life.

c) The advanced meter infrastructure ("AMI") technology has evolved over the past 12 years so it is expected that the next generation of AMI will have a greater reach improving overall communication. However reliability of communication will still be largely dependent on location of the meter and availability of cellular coverage.

d) Response to part (b) is yes.

e) Drivers that determine useful life of smart meter are accuracy, consistency, display legibility, telecom technology obsolescence, and regulatory requirements (i.e. demand to interval).

Canadian Manufacturers & Exporters Interrogatory # 23

Issue:

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

Reference:

B1-01-01 Section 2.3 Page 38 figure 29

Interrogatory:

a) How long does it take the average wood pole to degrade from 'good condition' to 'poor condition'?

b) Does Hydro One take that time period into account when determining their expected service lives?

Response:

a) Newly installed poles are considered to be in "good" condition. Poles that require replacement are considered to be in "poor" condition. The expected service life is defined as the time from when a pole is newly installed to when it requires replacement. Given these definitions, the average time for a wood pole to degrade from "good" condition to "poor" condition is equal to the expected service life, approximately 62 years.

b) Yes. See response to part (a).

Canadian Manufacturers & Exporters Interrogatory # 24

Issue:

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

Reference:

B1-01-01 Section 3.2 Page 1 and 2, Table 54 and 55

Interrogatory:

a) If possible, please provide updates to Table 54 and 55 with 2017 actuals.

b) If that information is not available, when will it become available?

Response:

a) 2017 Audited actuals are not available and will be provided once they are.

b) As indicated in the cover letter of this submission.

Canadian Manufacturers & Exporters Interrogatory # 25

Issue:

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

Reference:

Q-01-01 Page 13

Interrogatory:

Hydro One states: "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."

a) Will Hydro One be patrolling 1/3 of the distribution network each year such that the whole distribution network is patrolled every three years, or are certain areas targeted due to higher growth or vegetation profile?

b) If areas are cleared of defects, and not patrolled for a year or more, what is the expected likelihood of having previous growth that was not identified as a defect causing outages in the interim?

Response:

a) For the Defect Correction program, Hydro One will be patrolling one third of the distribution network each year such that the whole distribution network is patrolled every three years.

b) The definition of a defect, as defined in Exhibit Q, Tab 1, Schedule 1, includes vegetation that is expected to grow into energized equipment within the maintenance cycle, thus the likelihood of having a grow-in outage within the maintenance cycle is low.

Canadian Manufacturers & Exporters Interrogatory # 26

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

Reference:
Q-01-01 Page 13
B1-01-01 Section 1.6 Attachment 2 Page 32

Interrogatory:
At page 32 of the Hydro One Vegetation Management Study, CN Utility Consulting states that Integrated Vegetation Management is considered the most universal best management practices by a number of groups. According to the report, the key to IVM is the use of herbicides when growth is a brush, before it becomes a tree.

a) Does the defect correction program's activities line up with the tenets of IVM?

b) Does the removal only of defects in the distribution area lead to the growth of non-defective brush into trees, thus making it more difficult to remove if they ever become defective?

Response:
a) Yes, the defect correction program adheres to the Integrated Vegetation Management decision making process outlined in ANSI A300 Part 7.

b) The Defect Correction program is only one component of Hydro One's approach to managing vegetation risk. A portion of the maintenance activities described in the Public Safety and Reliability Program in Exhibit Q, Tab 1, Schedule 1, will focus on cost effectively treating vegetation that poses a long term defect risk.

Canadian Manufacturers & Exporters Interrogatory # 27

Issue:

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

Reference:

Q-01-01 Page 14

Interrogatory:

Hydro One states: "Hydro One views the 2018-2022 period as transitional, and Hydro One anticipates incurring transition costs with this new approach."

a) Please provide a reference to where in the evidence the anticipated transition costs are provided. If there is not yet evidence on this matter, please provide a complete breakdown of the anticipated transition costs that Hydro One will incur by changing its approach to vegetation management, and a brief summary about why and how those costs will be incurred.

Response:

a) There are two primary components of the transition costs:

- The elimination of 798,000 backlogged defects. Eliminating this backlog is estimated to cost $127.7 million between 2018 and 2022.

- Change management activities required to support the new vegetation management approach. These include reorganizing the forestry department to support the new program approach and training/auditing against the new work specification. Costs associated with these activities are estimated at $2 million and will be incurred in 2018.

Canadian Manufacturers & Exporters Interrogatory # 28

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

Reference:
Q-01-01-02 Page 14 Table 8

Interrogatory:
Table 8 provides cost projections for a three year cycle in zones A through D, and total annual and 3 year cost projections.

a) Please provide a reference in the evidence to a table that compares the cost projections in table 8 to Hydro One's previous cost projections under the old vegetation management cycle. If one is not yet available, please complete such a table.

Response:
a) Please see table below for a Provincial comparison between the old and new vegetation management programs in terms of 2018 program targets and cumulative 3 year forecast. Under the new program, high criticality defects will be managed across the whole system in a three year period whereas under the full corridor clearing approach, only approximately one third of the system would have been addressed. Forecasts at the climatic zone level are not available.

	Old Vegetation Management Strategy		**New Vegetation Management Strategy**	
	2018 Totals	**Total after 3 years**	**2018 Totals**	**Total after 3 years**
Kilometers Completed	12,000 km	37,360 km	34,666 km	104,000 km
Trees Treated	850,000	2,550,000	730,000	2,190,000
Total Cost	$149.6M	$448.8M	$149.6M	$448.8M

Canadian Manufacturers & Exporters Interrogatory # 29

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

Reference:
B1-01-01 Section 3.6 Page 1

Interrogatory:
CME notes that a number of the system renewal and system access projects have been given a priority rating of "demand" (such as SR-01 and SS-01).

a) Please provide a breakdown of what projects in the "system renewal" category were impacted due to Hydro One's change in spending from $285 million to $252.2 million in 2017. Please provide the priority ranking of the impacted projects.

b) Please provide a breakdown of what projects in the "system service" category were impacted due to Hydro One's change in spending from $110.1 million to $66.6 million in 2017. Please provide the priority ranking of the impacted projects.

Response:
a) A breakdown of the projects in the system renewal category that were impacted due to the change in the forecast spending in 2017 being $33 million below the previous approved plan is provided on page 5 of Exhibit B1, Tab 1, Schedule 1, DSP Section 3.6. The priority ranking for the impacted investments is Medium, with the exception of Distribution Lines PCB Equipment Replacement program which is High, as documented in the corresponding ISDs in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

b) A breakdown of the projects in the system service category that were impacted due to the change in the forecast spending in 2017 being $43 million below the previous approved plan is provided on page 5 of Exhibit B1, Tab 1, Schedule 1, DSP Section 3.6. The priority ranking for the impacted investment is High, as documented in the corresponding ISD SS-02 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8.

Power Workers' Union Interrogatory # 8

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

B1-01-01 Section 2.3 Page: 12

Interrogatory:

Distribution station transformer failures are highly impactful. Hydro One's distribution stations typically do not have on-site spare transformers that can be switched into service in the event of a failure, and load cannot be transferred amongst rural stations, which are most often fed from a radial system. In these instances, when a station transformer fails, service restoration requires the installation of a mobile unit substation.

a) Please describe the impacts, including costs, of typical major and non-major station transformer failures.

Response:

a) Please refer to interrogatory response Exhibit I-24-Staff-105 parts (b) and (d) for the impacts and costs related to historical major transformer failures. Unlike major station transformer failures, non-major failures typically do not result in customer interruptions; however the cost to replace a non-major failure is not materially different from the cost to replace a major failure.

Power Workers' Union Interrogatory # 9

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

N/A

Interrogatory:

a) Prepare and provide a chart which provides the following information for each year since 2007:
   i. The number of wooden poles beyond expected service life;
   ii. The number of wooden poles in "poor", "very poor", and "in need of replacement" condition;
   iii. The number of poles replaced as part of a planned work program; and
   iv. The number of poles replaced outside of a planned work program.

Response:

a) The information on poles is presented below.

   i. Please see table below for the number of poles beyond expected service life.

	2014	2015	2016	2017
Poles 62 years or older	209,653	223,673	249,231	277,950

   ii. Please refer to interrogatory response Exhibit I-24-AMPCO-23 for the number of poles in poor condition.

   iii. Please refer to interrogatory response Exhibit I-24-AMPCO-25 for the number of poles planned for replacement.

   iv. Hydro One generally assumes about 12,000 poles are installed through other programs on an annual basis.

Power Workers' Union Interrogatory # 10

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

Exhibit B1, Tab 1, Schedule 1, Page 13

Interrogatory:

Hydro One indicates that it "proposes to cease reporting the Number of replaced Poles" as this is a measure which is "activity-based", which is not consistent with the RRF.

a) Why does Hydro One not consider the number of poles replaced to be an "outcome"?

b) Why isn't this information critical to the Board's understanding of the adequacy of Hydro One's efforts to maintain its infrastructure on a sustainable basis?

c) Does Hydro One plan on continuing to track the number of poles replaced on an annual basis, in order that the data remains available to the Board?

Response:

a) B1-1-1, DSP Section 1.4, page 1 line 21 to page 2 line 9 describes how the outcome measures were selected. "Number of Poles Replaced" is a measure of activity. The new "Pole Replacement – Gross Cost per Unit in $" shown in B1-1-1, DSP Section 1.4, Table 8 – Distribution OEB Scorecard, is an outcome that better indicates continuous improvement and benefit to the customer.

b) The total number of poles replaced is an important measure of activity. Hydro One will still be planning the program to replace a prudent number of poles based on asset needs as seen in B1-1-1 DSP Section 3.8 ISD: SR-09.

c) Yes

Power Workers' Union Interrogatory # 11

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

N/A

Interrogatory:

a) How many wood poles does Hydro One forecast as newly becoming "in need of replacement" in each year from 2018-2022?

Response:

a) For the period of 2018 to 2022, about 67,000 poles in total (or 13,400 per year) will become in need of replacement.

Power Workers' Union Interrogatory # 12

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:
N/A

Interrogatory:
Assuming that the work plan anticipated in the application with respect to pole replacement for 2018-22 is actually undertaken, at the end of 2022:

a) Would the total number of poles beyond expected service life be greater than, or less than the total number of poles beyond expected service life at the end of 2017? By what amount?
b) Would the average age of poles beyond expected service life be older or younger than the average age of poles beyond expected service life at the end of 2017? What are the average ages for each cohort at those two points in time?

Response:
Hydro One does not replace poles solely to maintain a specific demographic parameter (e.g. total number of poles beyond expected service life, average age of poles beyond expected service life). In a hypothetical scenario where such an age based replacement strategy is implemented ignoring condition data:

a) At the end of the plan the total number of poles beyond their expected service life will be greater than in 2017. Based on the replacement rates in ISD SR-09 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 there will be 337,000 poles beyond the expected service life at the end of the plan.

b) At the end of the plan the average age of a pole beyond the expected service life will be older than in 2017. Based on the replacement rates in ISD SR-09 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 the current average age beyond the expected service life is 66 years and after the plan the age will be 68 years.

Witness: GARZOUZI Lyla

Power Workers' Union Interrogatory # 13

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

N/A

Interrogatory:

What additional funding in capital and OM&A would be required in order to execute a work plan which would result in:

a) The total number of poles beyond expected service life at the end of 2022 being no greater than the total number of poles beyond expected service life at the end of 2017; and

b) The average age of poles beyond expected service life at the end of 2022 being no older than the average age of poles beyond expected service life at the end of 2017?

Response:

Hydro One does not replace poles solely to maintain a specific demographic parameter (e.g. total number of poles beyond expected service life, average age of poles beyond expected service life). In a hypothetical scenario where such an age based replacement strategy is implemented ignoring condition data:

a) The number of poles currently beyond the expected service life of a new pole is 280,000. To maintain this demographic, an additional 54,000 poles would need to be added to the five year plan requiring an additional $394 million in net capital.

b) The current average age of a pole that is beyond the expected service life of a new pole is 66 years. To maintain this demographic, an additional 85,000 poles would need to be added to the five year plan requiring an additional $681 million in net capital.

Power Workers' Union Interrogatory # 14

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

B1-01-01 Section 3.8 ISD-SR-09 Page: 1

As outlined in DSP Exhibit 2.3, there are currently approximately 67,000 poles in poor condition that are at high risk of failure. By the end of 2022, it is forecasted that an additional 77,000 poles will be added to this high risk category due to deteriorating condition.

In addition to concerns with condition, there are still a subset of 39,000 red pine poles that are demonstrating premature degradation, as documented in previous proceedings (EB-2013-0416, EB-2012-0136 and EB-2009-0096), that require replacement.

B1-01-01 Section 3.8 ISD-SR-09 Page: 2-3

There are currently a large number of poles in poor condition that are at high risk of failure and it is forecasted that this number will be slightly reduced to 99,000 poles (including the red pine pole subset) over the plan. Poles are prioritized for replacement based on their impact on reliability and potential safety risks. The table below outlines the planned volume of poles to be replaced throughout the five year period.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Poles Replaced	9,600	14,300	16,000	16,123	16,128

B1-01-01 Section 1.1 Page: 8 or 23

The pole replacement program will be replacing 77,400 poles over the planning period to manage the volume of poles in poor condition.

Interrogatory:

a) Does the total number of poles that are in poor condition (67,000) include the 39,000 red pine poles?

b) How many poles would be at high risk of failure by the end of the test period if Hydro One continued at its current pole replacement rate?

c) The DSP overview states that 77,400 poles will be replaced over the test period. The sum of pole replacements in ISD-SR-09 is 72,151. Please explain the discrepancy.

Response:

a) No.

b) Under the historic rate there would be 113,000 high risk come end of plan, with the proposed plan replacement of 72,151 poles this will be reduced to 99,000 high risk.

c) The correct number is 72,151. The reference to 77,400 poles was a typographical error; the number was not updated to reflect the final decision to proceed with Plan B – Modified.

Power Workers' Union Interrogatory # 15

Issue:

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

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

N/A

Interrogatory:

a) Confirm that, but for concerns regarding customer bill impacts, Hydro One would have agreed with its asset managers that Plan A was the appropriate workplan for Hydro One's assets and its customers.

b) Confirm that, aside from vegetation management issues, Hydro One did not re-visit the issue of whether Plan A, B, or modified B was the optimal plan to pursue.

c) In view of the fact that a significant proportion of Hydro One's customers are being protected from bill impacts for the foreseeable future, why isn't the 2018-22 timeframe the ideal timeframe to ensure that Hydro One's asset condition and reliability are improved (or at least are no worse)?

d) Confirm that the effect of pursuing modified Plan B rather than Plan A or Plan B is to defer the incremental costs associated with those plans from a period of time where a significant proportion of customers have bill impact protections under the FHP, to a period of time when they will be lacking such protection.

Response:

a) Plan A mitigates the most risk from a system and asset needs perspective, but Hydro One's Board of Directors did not accept it given customer feedback on rate increases. Based on feedback from the Board of Directors, Hydro One's management team developed Plan B Modified.

b) Hydro One can confirm that it did not revisit this decision.

c) Through Hydro One's customer engagement process, it was determined that keeping rates low was a top priority for customers. Plan B Modified was selected to balance customer needs with other business needs identified through the needs assessment process while allowing Hydro One to deliver on its business objectives. Please see section 1.3.4 (How the Plan Reflects Customer Needs and Preferences) of the DSP for details.

d) Plan B Modified defers some capital expenditures to later years in the planning period in order to mitigate rate impacts to customers while maintaining an acceptable overall risk profile. Hydro One makes no assumptions about the future of the Fair Hydro Plan.

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	

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

Source: D2-2-3

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

School Energy Coalition Interrogatory # 53

Issue:

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

Reference:

B1-01-01 Section 3.8

Interrogatory:

SEC is seeking to understand the full business cases that underlies the capital projects discussed the various Investment Summary Documents. SEC has randomly selected a set of capital projects instead of asking for every business case. For each of the following capital projects, please the full internal business case:

	ISD	Program	Project
1	S-01	Transformer Replacements	Blind River DS - T1
2	S-01	Transformer Replacements	Young Jet RS - R1
3	S-03	Spill Containment	Little Britain DS
4	S-03	Spill Containment	Reach Road RS
5	S-05	Recloser Upgrades	Exeter Rosemount DS - F3
6	S-05	Recloser Upgrades	Brighton Pinnacle DS - F2
7	S-07	Station Refurbishments	Black Corners DS
8	S-07	Station Refurbishments	Madoc Madawaska DS
9	S-07	Station Refurbishments	Punkidoodles Corners DS
10	S-12	Lines Sustainment Initiatives	Havelock TS 57M2 Relocation Phase 1 of 2
11	S-12	Lines Sustainment Initiatives	Flynn's Corners DS F3 Phase 1 of 2
12	D-02	System Upgrades Driven by Load Growth	Arnprior Elgin DS Upgrades
13	D-02	System Upgrades Driven by Load Growth	Goodfish DS Voltage Conversion
14	D-05	Asset Life Cycle Optimization and Operational Efficiency	Grand Bend Municipal DS F3 Voltage Conversion
15	D-05	Asset Life Cycle Optimization and Operational Efficiency	Eugenia RS Relocation
16	D-06	Reliability Improvements	Orangeville TS Tie Line
17	D-06	Reliability Improvements	Armitage TS M34 Line Extension
18	C-05	Security Infrastructure	Seagrave DS
19	C-05	Security Infrastructure	Glenarm DS

Response:

A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution.

Investments that are classified as programs are authorized for expenditure with the approval of the Business Plan by the Board of Directors. The below list of investments are program work and therefore do not have a business case produced for the purposes of authorizing the expenditure of funds for execution:

- S-01 Transformer Replacements
- S-03 Spill Containment
- S-05 Recloser Upgrades
- S-07 Station Refurbishments
- S-12 Line Sustainment Initiatives
- C-05 Security Infrastructure

The following list of investments are projects and will require a business case. However these projects are planned to be in service at a future date, and as such a business case has not yet been produced for the purpose of authorizing the expenditure of funds for execution.

- D-02 System Upgrades Driven by Load Growth
- D-05 Asset Life Cycle Optimization and Operational Efficiency
- D-06 Reliability Improvements

School Energy Coalition Interrogatory # 54

Issue:

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

Reference:

B1-01-01 Section 1.4 Page: 6

Interrogatory:

Please explain why Hydro One's target Pole Replacement – Cost Per Pole metric is increasing in 2017 and 2018.

Response:

The increase between 2017 and 2018 is about 1 per cent. This increase is due to the estimated inflation rate of about 2 per cent (labour rates, material costs, TWE prices, etc.), and is partially offset by the savings described in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.5, s.1.5.1 Productivity Savings in the Plan, which has been updated in Exhibit I-25-Staff-123.

School Energy Coalition Interrogatory # 55

Issue:

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

Reference:

B1-01-01 Section 2.1

Interrogatory:

Please update Table 31 with the most recent HIS Global Insight forecast data.

Response:

Table 31 - IHS Global Insight's November 2017 Forecast

%	Historical Years					Bridge Year	Test Years				
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Distribution Cost Escalation for Construction	2.9	3.5	2.9	2.5	-0.6	1.9	2.5	2.7	2.9	3.0	2.9
Distribution Cost Escalation for Operations & Maintenance	2.3	0.8	0.7	-0.8	-0.8	1.4	1.4	1.8	2.1	2.0	1.9

School Energy Coalition Interrogatory # 56

Issue:

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

Reference:

Previous Proceeding: EB-2013-0416, D2-2-2

Interrogatory:

Please provide a similar schedule to show actuals for 2015 and 2016 capital spending and 2017 forecast capital spending, for each capital expenditure program/project.

Response:

Please refer to Exhibit I-24-SEC-42.

School Energy Coalition Interrogatory # 57

Issue:

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

Reference:

B1-01-01 Section 3.8, SS-01

Interrogatory:

The Investment Summary Document for the Remote Disconnection/Reconnection Program states that one of the benefits will be achieving operational efficiencies. Please provide a copy of the business case for this program and the calculation of the approximately $4.5M in annual cost savings identified.

Response:

As stated in interrogatory response Exhibit I-24-Staff-115 part (d); Hydro One's process is to initiate and approve business cases for project work; program work is approved with the business plan by the Board of Directors. This Remote Disconnection/Reconnection investment (SS-01) over the five year plan is program work and therefore does not have a business case.

The $4.5 million of annual cost savings arises from the elimination of the second site visit to reconnect the meter (as per the table below). These savings have been incorporated in the Customer Service OM&A (Exhibit C1, Tab 1, Schedule 5).

	2018	**2019**	**2020**	**2021**	**2022**	**Totals**
Remote Disconnect Meters	11,875	11,500	11,125	10,750	10,375	55,625
Savings	$4.8M	$4.6M	$4.5M	$4.3M	$4.2M	$22.3M
Average Savings over 2018 to 2022 period						**$4.5M/meter**

School Energy Coalition Interrogatory # 58

Issue:

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

Reference:

B1-01-01 Section 3.8 GP-01, Page 3

Interrogatory:

For each of the various fleet requirement types included on Table 1, please provide the total number of units Hydro One currently has.

Response:

Below is the current number of units by equipment type.

Equipment Type	Equipment count as of January 24, 2018
Light	2,720
Heavy	1,413
Off-Road	474
Miscellaneous	2,599
Helicopter	7
Total	**7,213**

School Energy Coalition Interrogatory # 59

Issue:

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

Reference:

B1-01-01 Section 3.8 GP-02, Page 5-6

Interrogatory:

Please explain how Hydro One derived the forecast cost for the Real Estate Field Facilities Capital.

Response:

The Real Estate Field Facilities Capital Program is primarily compromised of capital sustainment work with respect to existing facilities and major work initiatives.

The capital sustainment includes replacement of major building system/components including roof structures; windows and cladding; heating, ventilating and air conditioning (HVAC) systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at end of life.
The forecast costs are derived based on need that is prioritized by facilities conditions assessments and cost estimates of work based on historic / vendor estimates.

The major work initiatives include addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements. The forecast costs are derived based on currently identified investment needs that are prioritized in terms of cost effective strategy that addresses HONI operational requirements and estimates are established through the use of a scalable template design and experience from recently completed projects.

School Energy Coalition Interrogatory # 60

Issue:

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

Reference:

B1-01-01 Section 3.8 GP-16, Page 5

Interrogatory:

Please explain how Hydro One derived the forecast cost for the Customer Self-Service Technology program.

Response:

The cost estimate is based on preliminary scope and research. Final costs will be determined using Hydro One standard methodology which includes a competitive Request for Proposal (RFP) process.

School Energy Coalition Interrogatory # 61

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

Reference:
B1-01-01 Section 3.8 GP-18
With respect to the Integrated System Operations Centre:

Interrogatory:
a) [EB-2013-0416, Ex. D2-2-3-O-04] In EB-2013-0416, Hydro One sought approval for expenditures related for a Back-Up Control Centre at a cost of $18.8M. The current Integrated System Operations Centre appears to be a project of similar scope and is forecast to cost $56.4M. Please explain the evolution of the project and the significant increase in cost.

b) Please provide a copy of the full business case for the project.

c) Please provide a copy of the ‘extensive Market Assessment” that selected the Orillia site.

d) Please confirm that this facility is the ‘advanced technology hub’ that has been referenced in local Orillia media (for example: http://www.orilliapacket.com/2016/08/15/orillia-sells-opdc-to-hydro-one-for-2635m].

Response:
a) The current project is not of a similar scope. The initial planner’s estimate was exclusively for a Back-Up Control Centre, based upon two key assumptions: it was to be built on Hydro One land, and telecommunication infrastructure would be available.

b) As the project evolved, Hydro One conducted a planning needs assessment, to assess complimentary requirements across the company and identify the optimal way to fulfill business needs. Coming out of the needs assessment, it was learned that multiple lines of business required the same critical support infrastructure. As a result, a scope was created for an Integrated System Operations Centre, which added the following functionalities:

- An Integrated Telecommunication Management Centre,
- A Security Operations Centre,
- A Security Event Monitoring Centre,
- Office space for Operating support staff, and
- Incremental data centre space to relieve constraints at the existing data centre and accommodate the additional lines of business at the ISOC.

Furthermore, the ISOC necessitated new land acquisition and telecommunication infrastructure. These above noted changes to scope led to the cost increases.

c) The business case is still being finalized and will be provided once it is approved.

d) The Market Assessment was completed by ATA Real Estate Advisors and enclosed as attachment 1.

e) The ISOC is a component of the “advanced technology hub”, which also includes a provincial warehouse and regional operations centre. Please note: the example link in the question returns “Page Not Found”.

ATA Real Estate Advisors

PROPERTY APPRAISAL OF

BUCC
Alternate Site Opportunities

PREPARED FOR

Hydro One Networks Inc.
185 Clegg Road
Markham, ON L6G 1B7

ANDREW, THOMPSON & ASSOCIATES LTD.
642 Welham Road, Suite 103
Barrie, ON L4N 9A1

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PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

ATA Real Estate Advisors

March 6, 2015

Hydro One Networks Inc.
185 Clegg Road
Markham, ON L6G 1B7

Attention: Mr. Robert Churcher

Re: BUCC – Alternate Site Opportunities

Dear Mr. Churcher:

Further to your request, we provide this draft report addressing the site search for a suitable and well located property to develop a new BUCC (Back-Up Control Centre) facility. We have thoroughly considered your requirements as outlined in the RFP and in our start up meeting. This report has been prepared based on our understanding of the identified criteria.

Further to your instructions, we have conducted a market investigation for properties available or suitable for the acquisition and development of the BUCC. The alternatives are based on a variety of site criteria within the provided geographic boundaries identified within the RFP with a focus on the seven market areas identified as potential locations for the alternate BUCC site.

Our research to date including all municipal inquiries has been held confidential.

We do not have any conflicts of interest to disclose which emerged from the work completed to date.

This consulting report is intended to be consistent with the Terms of Reference and in accordance with the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) adopted by the Appraisal Institute of Canada.

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TABLE OF CONTENTS

1.0 STUDY FRAMEWORK

Hydro One Networks Inc. (HON) is searching for a location for a new Back-Up Control Centre (the "BUCC"). This market investigation identifies properties available for the acquisition and development of a BUCC based on a variety of site criteria within pre-selected geographic boundaries.

The Ontario Grid Control Centre (the "OGCC") located at 49 Sarjeant Drive in Barrie, Ontario serves as the Distribution Operating Management Centre. Integral to the OGCC is a BUCC, which duplicates the features, functionality and operating ability of the primary facility in the event of loss of control.

The current BUCC is no longer considered suitable to meet HON's business or operational requirements and this site opportunity study is in support of the search for a property to develop a new facility.

1.1 General Parameters

- Separation from Barrie BUCC

  The BUCC should be spatially separated from the OGCC to ensure that no single mode, event or failure can render both the primary and backup facilities inoperable and or uninhabitable. This includes both natural events, such as flooding and severe storms, to incidents related to the manmade environment, such as highway and rail incidents. We understand that the BUCC should be located a sufficient distance away from the primary facility so that no single event renders both inoperable, i.e. greater than 15km.

  Secondary considerations should be given to the amount of time required to travel from the OGCC to the BUCC.

- Natural Barriers

  Site conditions that would restrict development and access. Sites with open storage adjoining are less favorable.

- At Risk Uses

  Ideally there should be no opportunity for nearby development that may pose a security risk, risk of hazardous/explosive substances, industrial vibration etc..

- Fibre Optic services

  Ideally located at the street frontage or in close proximity.

- Services

  To be in place or assured no later than 2017.

1.2 Essential Site Criteria

The following outlines the provided ideal criteria:

- Site area of approximately 5 acres or greater;
- Full municipal services, including water, sanitary, gas, hydro and telecommunications;
- Two road frontages or two or more access routes;
- Permit a building program of up to 50,000 square feet;
- Parking for 175+ staff and visitors;
- Proximity to hotels and food services, less than 30 km;
- Proximity to emergency services, e.g. police and health services, less than 30 km;
- Unrestricted helicopter flight and landing for emergencies;
- Located away from a flight path to an existing or future airport;
- Located away from an existing or future major highway;
- Located away from a railway corridor;
- Located away from a heavy industrial area, in particular bulk or container storage facilities, processing plants or hazardous industries/uses;
- Low visibility to surrounding land uses;
- Secure location, ideally with natural barriers
- Proximity to Hydro One Telecommunications

1.3 Geographic Boundaries

Generally the study area is to be within the 80 km radial distance from the OGCC however this study area was further revised to be north of Aurora and south of Gravenhurst.

The municipalities that were specifically identified for consideration included the following:

- Collingwood
- Wasaga Beach
- Midland / Penetanguishene
- Orillia
- Bradford Area
- Newmarket Area (North-West of City Centre)
- Orangeville Area (North-East of City Centre)

Other municipalities that have been given consideration based on ATA’s review of the criteria include the following:

- Alliston (New Tecumseth)
- Angus
- Innisfil
- East Gwillimbury
- Schomberg (King Township)

1.4 Understood Order of Importance

Table 1

Ranking	*Characteristic*
1	*Site*
2	*Servicing*
3	*Municipality Factors – Land Use*
4	*Availability*
5	*Development*
6	*Power Supply*
7	*Communications*
8	*Other*

2.0 SCOPE OF WORK UNDERTAKEN

We have reviewed the identified areas to determine vacant sites that were serviced and would meet the size requirements, considered the prevailing MLS (active and expired) for the market areas, contacted the Economic Development Department for each market area and consulted known market participants/vendors to source potential sites.

Sources of market evidence included reference to MLS records, records of Andrew, Thompson and Associates Ltd. together with information obtained from the development community. Zoning in the various municipalities were considered.

The analysis set out in this report relied upon written and verbal information obtained from a variety of sources considered reliable. Unless otherwise stated we did not verify client-supplied information, which we believed to be correct.

The work required conversations with Municipal Planning Departments as well interviews with owners, agents and developers in order to identify opportunities in both the identified market areas as well as other potential locations. All discussions were conducted with the strictest measures of confidentiality.

Based on the required criteria we have also:

- Provided an overview of the identified markets, including but not limited to the development environment with respect to current and prospective opportunities, expected land values and other relevant information required to evaluate identified sites.

- Searched the identified markets for properties meeting the identified criteria using the Multiple Listing Service and other data sources and mediums considered necessary to ensure that all possible opportunities are identified.

- Identified property alternatives in report format by geographic area supported by key and locational plans and such other plans and supporting information considered relevant for HON's consideration.

3.0 CONSULTING FRAMEWORK

3.1 Report Format

The Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) outlines the standard rules as it relates to the development and communication of a formal opinion of value and identifies the minimum content necessary to produce a credible report that is not misleading. The following reporting formats are available to the appraiser:

> ***Consulting*** - The development and communication of a real property consulting service must incorporate the minimum content necessary to produce a credible result that is not misleading.

This current consulting report is provided with regard to the rules and regulations as outlined in CUSPAP.

4.0 SITE REVIEW

4.1 Overview

Site recommendations have been listed in Section 4.4 and are fully summarized within the addenda of this report, with each study area included as a separate appendix. Institutional opportunities are summarized following, with additional background provided within the applicable study area appendix.

4.2 Institutional Opportunities

4.2.1 Opportunities on Provincial Lands

Table 2

Area	*Location*	*Comment*
Orillia	Former Huronia Regional Centre & Lands adjacent to the OPP Headquarters.	Government to Government surplus and sale which would require more time to secure than available to the client. We estimate that up to 3 years of co-ordination and agreement could be required with the Provincial Government based on our experience in similar development schemes. **Would not likely meet with required timing.**

4.2.2 Municipal Opportunities

A number of Municipal opportunities have been identified. These are in the form of actively marketed business park lands that are owned by the Municipality and available for purchase. These sites have been identified within the community summaries.

4.2.3 Federal Opportunities

No opportunities on federal land have been identified.

4.3 Land Use

Land Use applicable to the individual identified sites has been summarized within the site write-ups. Background Land Use documents can be provided on a site by site basis as requested by the client.

4.4 Summary Table of Site Recommendations

The following Table outlines the location and site size of the recommended sites. The sites for each area have been ordered from most suitable to less suitable based on the BUCC requirements. Other areas considered with no recommended sites are summarized / discussed in Table 4.

4.4.1 Recommended Sites

Table 3

Site Summary Table		
#	**Location**	**Site Size**
	Orillia	
1	Horne Business Park (University Av)	4.94 to 10+ acres
2	610 Harvie Settlement Road	5.93 acres
3	Infrastructure Ontario Lands (Near OPP Headquarters)	Various
4	James Street W & West Street S	5 to 20 acres
	Bradford	
1	3100 10th Sideroad	25 acres
2	3044 Line 8	51.12 acres
3	144 Dissette Street	6.86 acres
	Collingwood	
1	185 Mountain Road	20 acres
2	Raglan Street & Poplar Sideroad	25.6 acres
3	Other Mountain Road Opportunities	Various
	Alliston	
1	258 Church Street S	15.45 acres
2	Alliston Industrial Park	5 to 10 acres
3	6485 14th Line	12.55 acres
	Midland	
1	19628 Highway 12	14.85 acres
2	Highway 12 & Prospect Road	13.17 acres
3	1070 King Road	21.21 acres
4	Highway 12 & Brebeuf Rd	24.63 acres
5	16403 Highway 12	7 acres +/-
6	1337 Sundowner Rd	7.64 acres
	Penetanguishene	
1	Thompson Road & Robert Street	5 to 20 acres +/-
2	163 Robert Street	7 acres +/-
3	51 Dunlop Street	13.33 acres
	Orangeville	
1	Centennial Road & C Line	5.16 acres
	Newmarket	
1	1166 - 1186 Nicholson Road	5.67 acres
2	Harry Walker Parkway & Stackhouse Rd	11 to 21 acres

4.4.2 *Additional Study Areas Reviewed*

Table 4

Other Study Areas Considered
East Gwillimbury

• East Gwillimbury has a number of employment areas including Holland Landing, Green Lane, Bales Drive, Hwy 404/Queensville and Mount Albert.
 	
• Holland Landing - Employment lands are not currently serviced. Services are expected to be extended in the future but there is no definitive time frame. In addition we did not identify any actively listed properties suitable in this area.
 	
• Green Lane – A small pocket of fully serviced land at Harry Walker Pkwy are vacant but owned by build to suit companies with no interest in selling. Future development lands on the north side of Green Lane are offered but these appear to be more suitable for commercial and influenced by Highway 404.
 	
• Bales Drive – This is a partially serviced industrial park. Opportunity may exist in this area if sites on partial services are considered. Two vacant sites include:
  • 17551 Woodbine Ave – 14 acres – Offered at $5,500,000
  • Bales Dr @ Garfield Wright Blvd – 28.4 acres – Not actively listed
 	
• Highway 404/Queensville – This is a future employment area along the Highway 404 extension. These lands are not serviced at this time.
 	
• Mount Albert – A serviced site is available however it adjoins a rail line and this community is distant from the OGCC.

Angus
• Angus has a large parcel of industrial land at the southern limit of the community. This site has services extended to its frontage and may provide an opportunity to sever a 5 to 10 acre (or larger site). The larger 86 acre parcel is currently offered at $80,000 per acre. Due to the proximity to Base Borden, a major military base with airport we have excluded this community from further consideration but note an opportunity may be present.
Innisfil
• Innisfil's employment area is known as Innisfil Heights and is concentrated along Highway 400 at Innisfil Beach Road. Some larger sites are present but on private or partial services. We identified no fully serviced sites within the Town that are suitable for the proposed BUCC.
Schomberg (King Township)
• Schomberg has a moderate sized employment / industrial park at the northeast limit of the community. Some lands within the more recently serviced lands are available however these parcels range between 2 and 4.5 acres. These lands are marketed by Intercity Realty for an asking price of $450,000 to $500,000 per acre. Opportunity may exist to assemble a large enough site however privately owned sites not actively listed would also need to be pursued.

4.5 Conclusions:

- It is unlikely that an existing 5 – 8 acre parcel will be identified as a turnkey opportunity.
- The most desirable option appears to require severance or acquisition of a larger site.
- There appears to be more opportunities north of Barrie than south.
- There are very limited opportunities within the area of study which fall in York Region.

We trust this information meets with your approval and thank you for considering our firm.

Respectfully Submitted,
ANDREW, THOMPSON AND ASSOCIATES LTD.

____
L. Steve Thompson, BA, AACI, P. App.

____
Peter Spivey, B.Sc., AACI, P.App

5.0 SUMMARY OF QUALIFICATIONS

L. STEVE THOMPSON BA, AACI, P.APP.

Mr. Thompson studied economics at the University of Western Ontario entering directly into the appraisal field. Over twenty years of appraisal experience in the Barrie area has been primarily in ICI valuations. Computer software and real estate library development have been Mr. Thompson's secondary focuses. Consulting and appraisal services for a variety of institutional and corporate users has provided the opportunity to complete valuations for most types of non residential uses. Valuation for development properties, asset sales and adverse litigation matters have lead to experience at the Ontario Municipal Board and recognition with all levels of government, reputable lenders and corporate clients.

WORK HISTORY

1994 – Present	Partner – Andrew, Thompson and Associates Ltd.
1986 – 1994	Indicom Appraisal Associates - Barrie

QUALIFICATIONS

AACI (Accredited Appraiser Canadian Institute) – Granted May 1992

This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.

BA Bachelor of Arts – Economics (University of Western Ontario)

CERTIFICATES AND COURSES

Ontario Home Warranty Building Inspection Course, Part 9 – 1992
Reserve Fund Studies – REIC
Completion of the Eco Gift Seminar – 2006

ACHIEVEMENTS

Director, Ontario Expropriation Association, 2011
Director, Appraisal Institute of Canada, Ontario Association, 1997-2000
President, Rotary Club of Barrie Kempenfelt, 2003
Chairman, Strategic Planning, Ontario Association-AIC, 1999
Chairman, Professional Development, Ontario Association-AIC, 1997-2000
Vice Chairman, Governmental Affairs, Greater Barrie Chamber Commerce, 1997
Chairman, Lakeshore Task Force, Greater Barrie Chamber of Commerce, 1996
President - Thompson Realty Aurora Limited
Developer – Residential subdivision – Albert Heights – Hillsdale, ON

VALUATION EXPERIENCE

Land	Condominium Development Sites; Residential Subdivision; Industrial Subdivisions; Commercial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Airport Lands; Land Leases; Water Lots; Waterfront; Environmental Lands; Recreation Lands; Gravel Pits; Parking Lots, Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Motel; Hotel; Special Use; Marina; Freestanding; Office Buildings; Converted Dwellings; Historical Buildings; Campgrounds; Golf Courses; Trailer Parks; Mobile Home Parks; Camps; Restaurants; Lumber Yards; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Parking Facilities; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Sewage Facilities; Dump Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farm; Land; Severance consulting.
Unique	Waterfalls; Town Sites; Township Valuation; Ski Hills; Fish Hatcheries; Water Intake; Large Tracts; Industrial Shipping Docks; Historical, etc.
Consulting	Assessment; Expropriation; Peer Review; Education Development Charges; Alternative – Valuations; Cost Benefit Analysis; Highest and Best Use Studies; Equity Analysis.
Government Consulting	Native Land Claims; Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements; Groundwater Easements; Surface Easements; Subsurface Easement; Eco Gift Valuations; Intergovernmental Disputes; Environmental Acquisition's, etc.

EXPERT TESTIMONY PROVIDED TO / FOR

- Ontario Municipal Board
- Ontario Court of Justice
- Ontario Superior Court
- Private Arbitration Matters
- Alternative Dispute Resolution – ADR Chambers

PETER SPIVEY, B.Sc., AACI, P.App

Peter Spivey obtained his honours degree in biology with a minor in geography from the University of Guelph. Upon completion of his university degree, Peter Spivey entered the appraisal field and achieved his AACI (Accredited Appraiser Canadian Institute) designation, in 2009.

RELATED WORK HISTORY

2006 – Andrew, Thompson and Associates Ltd.

QUALIFICATIONS

AACI – Accredited Appraiser Canadian Institute

This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.

B.Sc. – Bachelor of Science

- Honours Marine and Freshwater Biology Major (University of Guelph)
- Geography Minor (University of Guelph)

CERTIFICATES AND COURSES

Standards Seminar – 2006
UBC - Real Estate Appraisal Course Stream (15 Courses)
Completion of the Eco Gift Seminar – 2010

VALUATION EXPERIENCE

Land	Residential Subdivision; Industrial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Waterfront; Recreation Lands; Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Special Use; Freestanding Office Buildings; Converted Dwellings; Restaurants; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Dump Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farm; Land.
Unique	Large Tracts; Large Institutional Buildings; Education Development Charges.
Consulting	Expropriation; Peer Review; Education Development Charges; Alternative - Valuations
Government Consulting	Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements, Eco Gift Valuations, Environmental Acquisition's, etc.

6.0 CONTINGENT AND LIMITING CONDITIONS

1. This consulting report has been prepared at the request of Hydro One Networks Inc. for the purpose of providing consulting advice with respect to site opportunities for a proposed BUCC. It is not reasonable for any other person than the (person) (those) to whom this report is addressed to rely upon this consulting report without first obtaining written authorization from the client and the author of this report. This report has been prepared on the assumption that no other person will rely on it for any other purpose and all liability to all such persons is denied.

2. This consulting report has been prepared at the request of, Hydro One Networks Inc. and for the exclusive (and confidential) use of, Hydro One Networks Inc. the recipient as named herein and for the specific purpose and function as stated herein. All copyright is reserved to the author and this report is considered confidential by the author and the client. Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication in any manner, in whole or in part, nor may it be disclosed, quoted from or referred to in any manner, in whole or in part, without prior written consent and approval of the author as to the purpose, form and content of any such disclosure, quotation or reference. Without limiting the generality of the foregoing, neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public in any manner whatsoever or through any media whatsoever or disclosed, quoted from or referred to in any report, financial statement, prospectus, or offering memorandum of the client, or in any documents filed with any governmental agency without the prior written consent and approval of the author as to the purpose, form and content of such dissemination, disclosure, quotation or reference.

3. The comments included in this consulting report have been founded upon a thorough and diligent examination and analysis of information collected. Certain information has been accepted at face value; especially if there was no reason to doubt its accuracy. Certain inquiries were outside the scope of this mandate. For these reasons, the analyses, opinions and conclusions contained in this report are subject to the following contingent and limiting conditions:

- The author of this consulting report cannot accept responsibility for legal matters, questions of survey, opinions of title, hidden or unapparent conditions of the properties, toxic wastes or contaminated materials, soil or sub-soil conditions, environmental, engineering or other technical matters, which might render these properties more or less valuable than as stated herein. If it came to our attention as the result of our investigation and analysis that certain problems may exist, a cautionary note has been entered in the body of this report.
- The description of recommended sites and the area of the sites were obtained from available sources such as Geowarehouse. This information has been assumed to be true with no in-depth analysis of these items completed which is outside of the scope of this consulting report.
- This report presumes that there are no outstanding liabilities except as expressly noted herein, pursuant to any agreement with a municipal or other government authority, pursuant to any contract or agreement pertaining to the ownership and operation of the real estate or pursuant to any lease or agreement to lease, which may affect the stated value or saleability of the subject property or any portion thereof.
- This report presumes that the real estate complies in all material respects with any restrictive covenants affecting the site, including all zoning, land use classifications, building, planning, fire and health by-laws, rules, regulations, orders and codes of all federal, provincial, regional and municipal governmental authorities having jurisdiction with respect thereto.
- No investigations have been undertaken in respect of matters, which regulate the use of the land. No inquiries have been placed with the fire department, the building inspector, the health department or any other government regulatory agency, unless such investigations are expressly represented to have been made in this report. The subject property must comply with such regulations and, if it does not comply, this non-compliance may affect the market value of this property. To be certain of such compliance, further investigations may be necessary.
- This report presumes that there are no actions, suits, proceedings or investigations pending or threatened against the real estate or affecting the titular of the recommended sites, at law or in equity or before or by and federal, provincial or municipal department, commission,

board, bureau, agency or instrumentality which may adversely influence the value of the real estate herein reviewed.

4. Should the author of this report be required to give testimony or appear in court or at any administrative proceeding relating to this report, prior arrangements shall be made therefore, including provisions for additional compensation to permit adequate time for preparation and for any appearances, which may be required. However, neither this nor any other of these contingent and limiting conditions is an attempt to limit the use that might be made of this report should it properly become evidence in a judicial proceeding. In such case, it is acknowledged that the judicial body will decide the use of this report that best serves the administration of justice.

5. This report is only valid if it bears the original signature and/or seal of the author.

7.0 CERTIFICATE OF THE APPRAISER

We certify that, to the best of my knowledge and belief:

- the statements of fact contained in this report are true and correct.
- the reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions, and are my personal, unbiased professional analysis, opinions and conclusions.
- we have no present or prospective interest in the property that is the subject of this report, and I have no personal interest or bias with respect to the parties involved.
- our compensation is not contingent upon the reporting of a predetermined value or direction in value that favours the cause of the client, the amount of the value estimate, the attainment of a stipulated result, or the occurrence of a subsequent event.
- our analysis, opinions and conclusions were developed, and this report has been prepared, in conformity with the Uniform Standards of Professional Appraisal Practice.
- no one provided significant professional assistance to the person signing this report.
- we are currently recertified under the requirements of the Appraisal Institute of Canada.

____

L. Steve Thompson, BA, AACI, P. App.

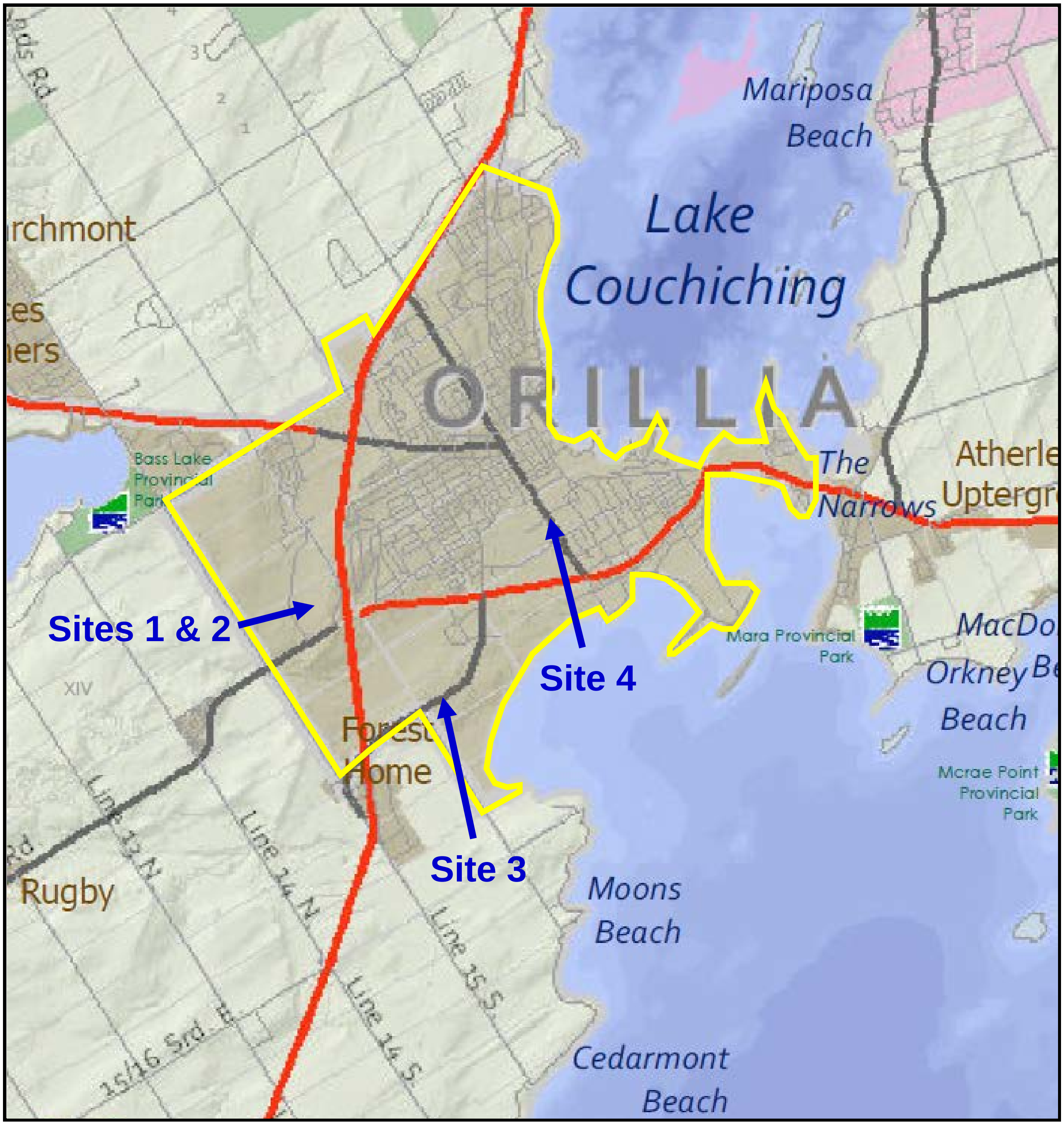
____

Peter Spivey, B.Sc., AACI, P.App

8.0 ADDENDA

- ***City of Orillia***
- ***Town of Bradford***
- ***Town of Collingwood***
- ***Town of Alliston (New Tecumseth)***
- ***Town of Midland***
- ***Town of Penetanguishene***
- ***Town of Orangeville***
- ***Town of Newmarket***

CITY OF ORILLIA



General Overview

The City of Orillia is located in the northeast sector of Simcoe County at the narrows between Lake Simcoe and Lake Couchiching. The City has developed along the west shore of both lakes. Orillia is 38kms north of the City of Barrie and approximately 129 km north of Metropolitan Toronto. Orillia is a small, stable, rural Ontario City. Retail sales benefit from the healthy tourist trade in the area. The real estate sector has fluctuated in unison with the economy of southern Ontario. Large institutional employers have a major impact on the local economy. The 2011 census identifies the population of Orillia to be 30,586.

Infrastructure:

The City of Orillia is a fully serviced community. Serviced industrial and business park uses are generally concentrated in 3 locations including the Drinkwater Industrial Park, Progress Industrial Park and the Norweld Business Park (West Street & James Street). These parks are generally built out. The City of Orillia recently created the Horne Business Park within a newly developing area west of Highway 11. The Horne Business Park is fully serviced and represents a large pocket of vacant employment lands.

Bell reportedly provides access to fibre optic networks through a large majority of the community. Hydro is provided by Orillia Power Corp.

Transportation

The arterial roads accessing Orillia are Highway 11, which connects Toronto to North Bay and Highway 12 connecting Whitby to Midland. These Highways produce heavy tourist and commercial traffic in the area. The Lake Simcoe Regional Airport, with passenger, freight, and full Canada Customs service, is 10 minutes away.

The primary access route between the Barrie and Orillia is Highway 11. A number of alternative routes are also present including Old Barrie Road, Ridge Road and Horseshoe Valley Road.

Hydro Control Centre to Community Limits

Primary Route	35 km +/- (20min)
Secondary Route	40 km +/- (35mn)

Development Activity / Charges

The City of Orillia has experienced slow to moderate growth with new residential being constructed in the West Ridge subdivision in addition to a number of small infill developments. Commercial and industrial development has been limited in recent years.

Development Charges

Industrial DC	No Industrial Development Charge to 2017
Institutional DC	$6.33 per sq.ft.

Tax Rates (Effective 2014)

Industrial (New Construction)	2.851049 %
Vacant Industrial Land	2.074163 %

Land Use

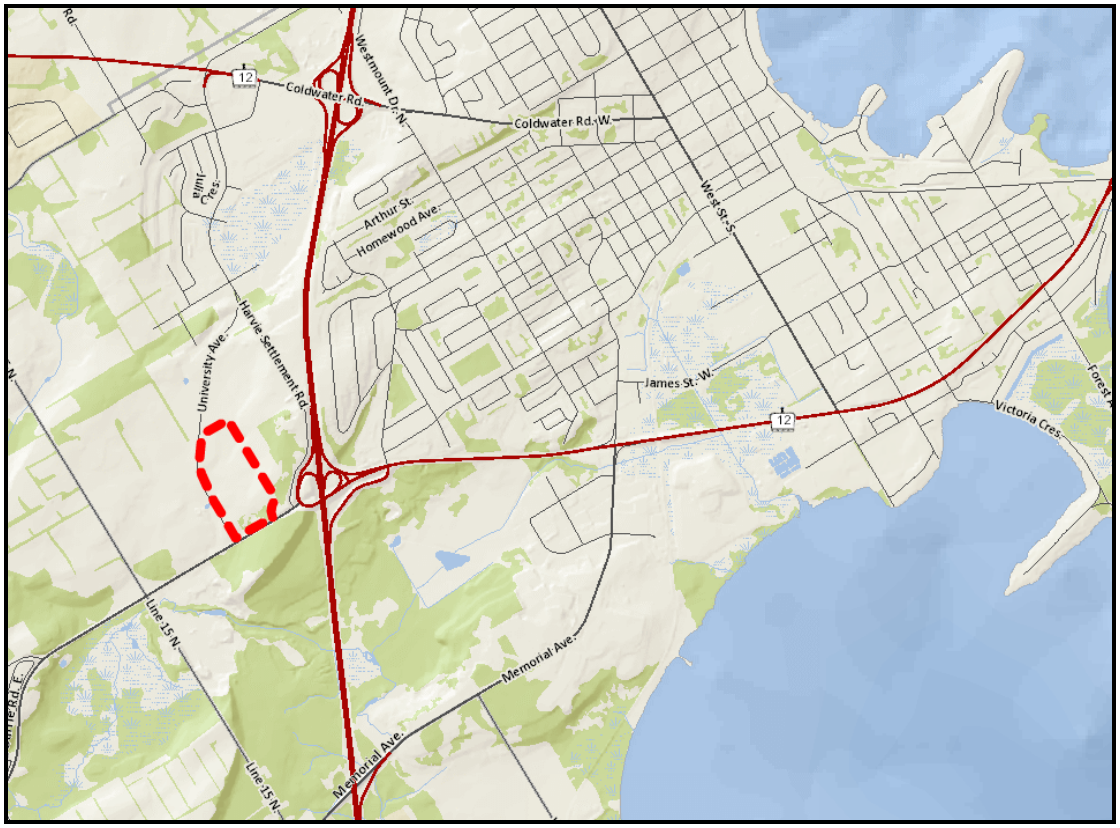
The most likely Official Plan designations that would allow for the BUCC use are Business Park/Industrial, Light Industrial Services and Institutional. The zoning by-law does outline "data centre" as a use which is likely similar to the proposed BUCC. Industrial zones M1, M2 and M3 allow for this use and would be most suitable for the BUCC use.

Recommended Site Summary Table:

Town	Orillia			
Site # / Ranking	**O1**	**O2**	**O3**	**O4**
Location	Horne Business Park (University Avenue)	610 Harvie Settlement Road (Toromont Site)	Infrastructure Ontario (Near OPP Headquarters)	James St W and West St S
Site Characteristics				
Size	4.94 to 10+ acres	5.93 acres	Various	5 to 20 acres
Interior / Corner	Interior or Corner	Interior	Mostly Interior	Interior and Corner
Road Access Routes	Multiple	Multiple	Multiple	Multiple
Road Frontage #	1 or 2	1	Unknown	1 or 2
Sanitary Services	Yes	Yes	Yes	Yes
Water Services	Yes	Yes	Yes	Yes
Fiber Optic	Yes	Nearby	Unknown	Unknown
Hydro Supply	44 kV in area	44 kV in area	44 kV in area	44 kV in area
Greenfield / Infill	Greenfield	Infill	Infill	Infill
Brownfield	No	No	Unknown	Potentially
Improved	No	No	Partially	No
Natural Buffer	No	No	Potentially	Potentially
Site Land Use (Zoning)	M1 - 1 (H) Special Industrial	M1-4 (H) Special Industrial Exception 4	CF & EP	M3-4, M3-5, EP-1 (M3 - General Industrial)
Surrounding Use Type*	BP, Ind, Res	Ind, EP, SC	I, Ind, EP	Ind, SC
Distance to Rail Line	Remote	Remote	Remote	Remote
Distance to Major Highway	300 m +/- to Hwy 11	150 m +/- to Hwy 11	0.2 to 2 km +/- to Hwy 11	2.8 km +/- to Hwy 11
Availability				
MLS / Private / Government	Municipal - Listed	Private MLS - Expired Listing	Provincially Owned Land	Not actively offered
Asking Price	$115,000 / acre	$680,800 $114,806 / acre	n/a	Estimated value under $115,000 per acre
Contact	Orillia Economic Development Office	Lauren Doughty (Previous Listing Agent)	n/a	n/a
Contact #	705-325-4900	416-495-6223	n/a	n/a

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Orillia Site #1
ADDRESS: Horne Business Park, Orillia



Nearest Intersection	University Ave & Old Barrie Road
Municipality	City of Orillia
Asking Price	$115,000 per acre
Asking $/Acre	$115,000 per acre
Listing Status	Actively Listed - Municipal Business Park
Listing Contact	Orillia Economic Development Office 405-325-4900
Owner	City of Orillia
PIN #	585720345 (Larger Parcel)

SITE INFORMATION

Lot Area (acres)	Various (5 to 10 Acres Possible)	**Services Available**	Water, Sanitary, Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located within a newly developed Business Park located to the west of Highway 11. A newly constructed road from University Avenue was installed by the City of Orillia. This area has been actively developing with a recreation complex and Lakehead University campus developing on the west side of University Avenue. No development has yet occurred in the Horne Business Park which is situated on the east side of University Avenue.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Business Park / Industrial
Zoning: M1-1 (H) – Special Industrial Exception 1

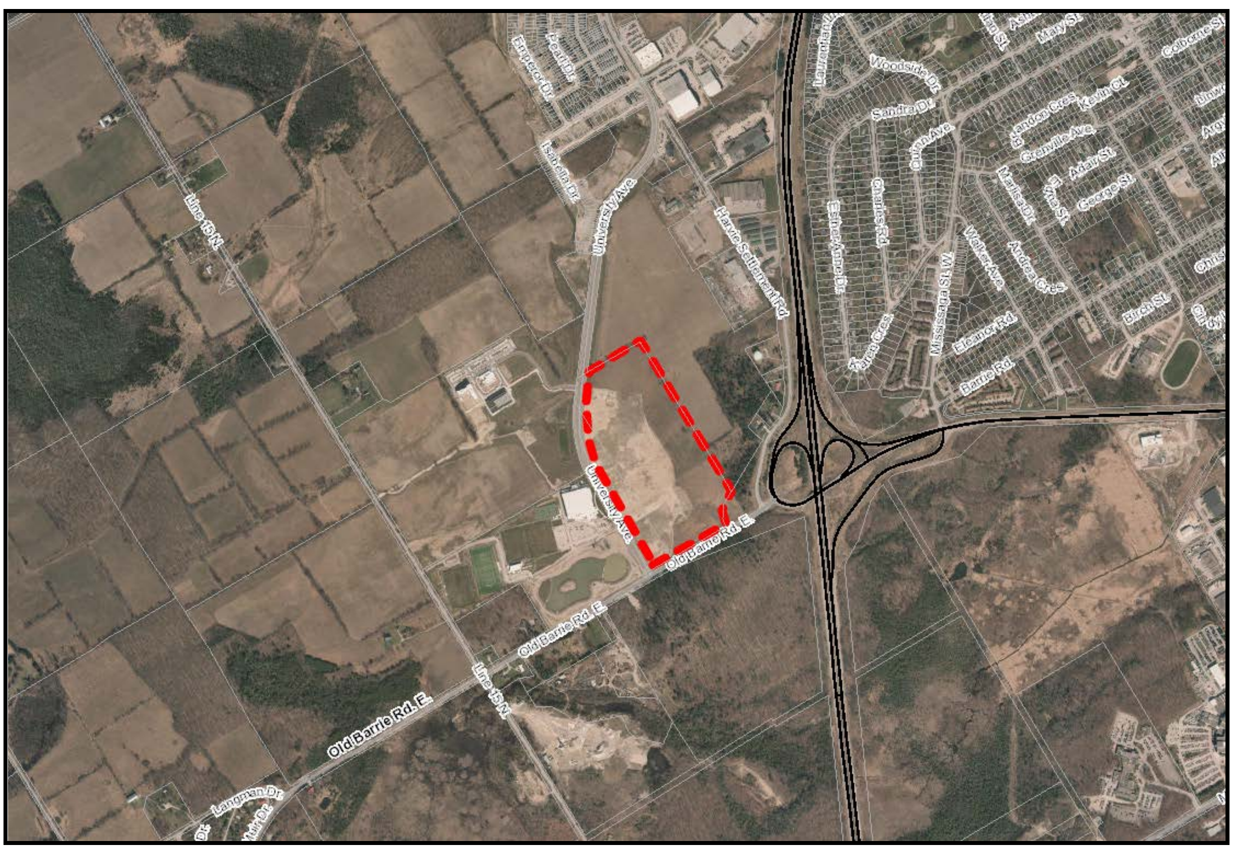
The Business Park / Industrial designation allows for a range of light industrial and business park uses. The zoning designation provides for business park uses with emphasis on research and development type uses such as a data centre. Outside storage of finished manufactured goods only are permitted. The proposed BUCC facility would be likely permitted on this site.

At this time the City of Orillia is in discussions with MTO regarding improvements to the intersection of Hwy 11 and Old Barrie Road located nearby. Any issues with these improvements are anticipated to be resolved in the short term and would not have an effect on the BUCC timing.</td></tr>
<tr><td>Site Description</td><td colspan="2">The Business Park has not yet been severed into individual parcels creating flexibility with regard to site size and configuration. The City has provided a conceptual lotting map which can be found on the following page. The lands are cleared.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior or Corner</td></tr>
<tr><td>Road Frontages</td><td>1 to 2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Bell nearby and to be extended in 2015</td></tr>
<tr><td>Hydro Supply</td><td>44 kV in Area</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>300m +/- to Hwy 11</td></tr>
<tr><td>Greenfield / Infill</td><td>Greenfield</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Severed based on requirement</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

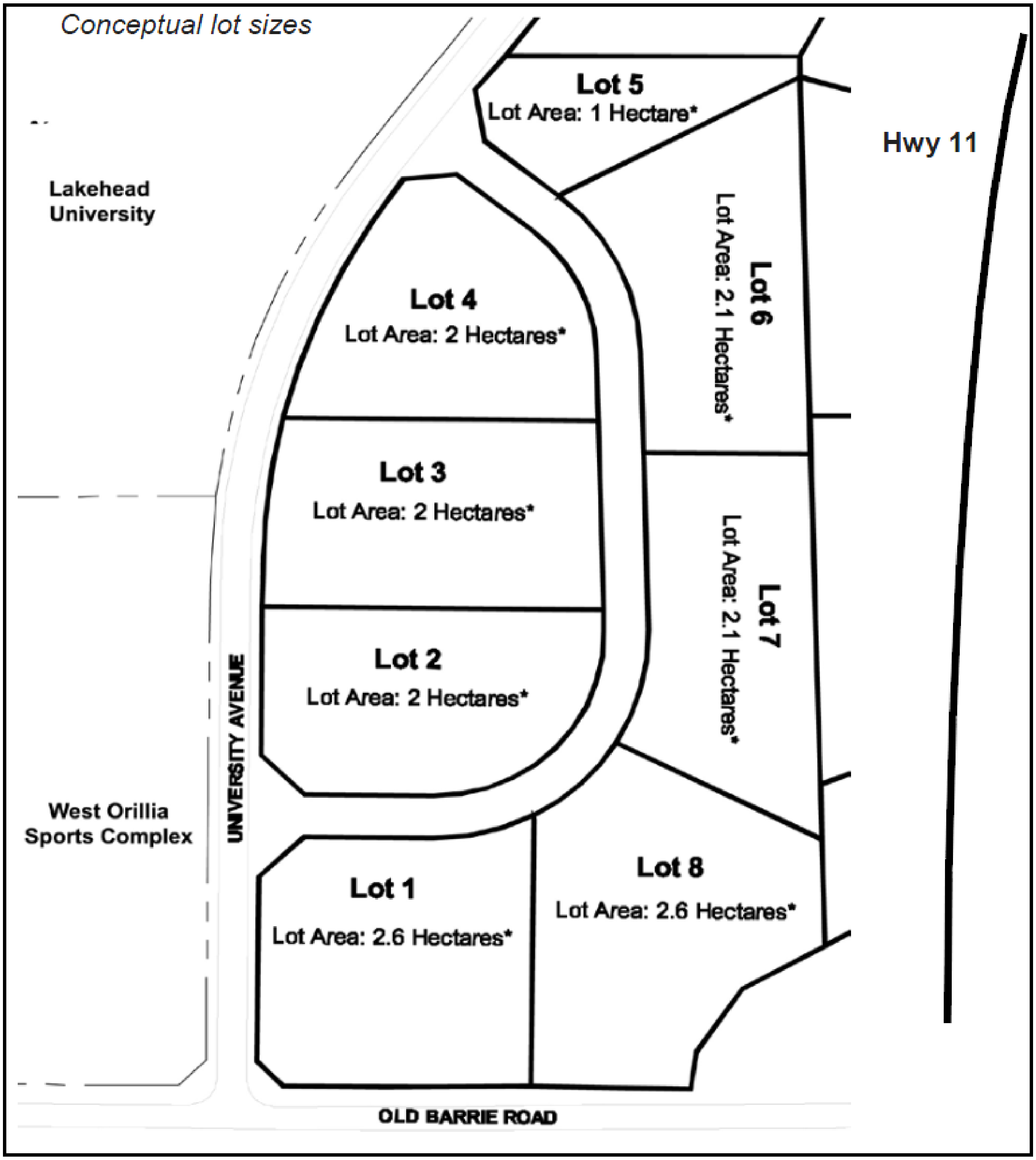
ADDITIONAL MAPS AND PHOTOS

Site Photo from University Avenue

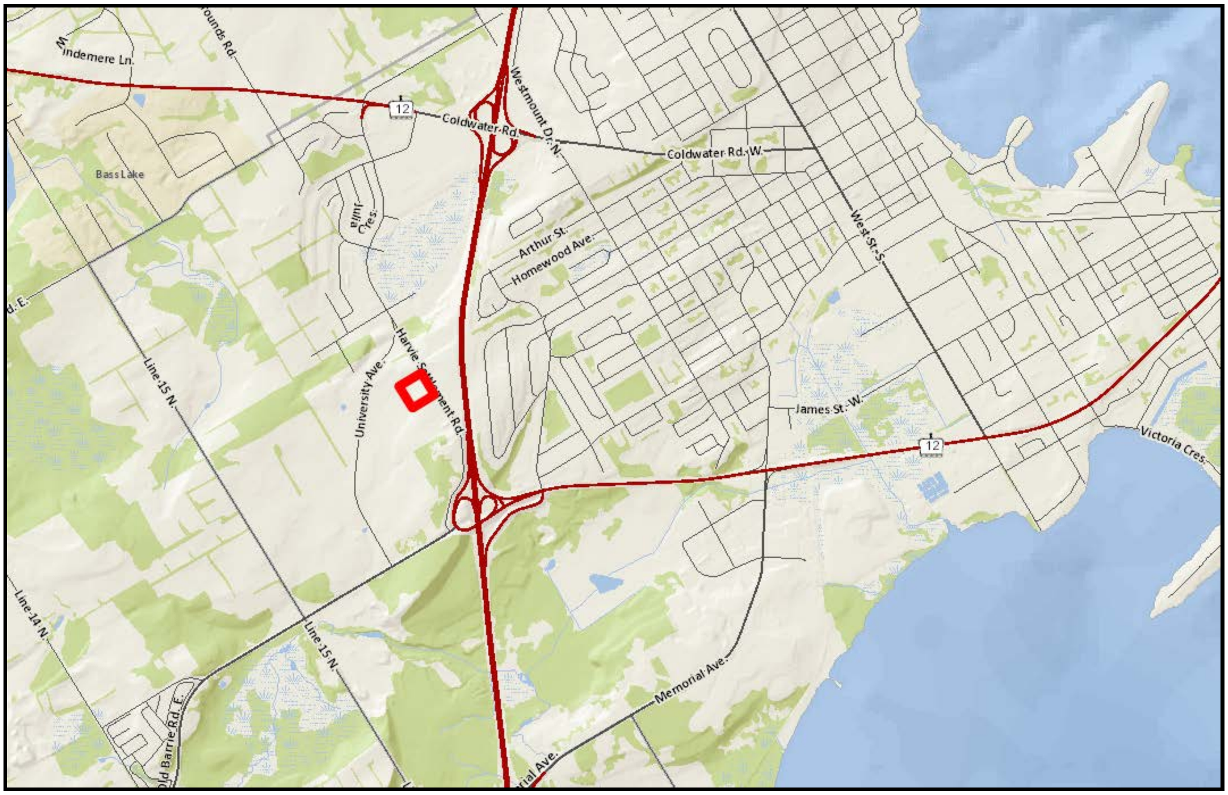
Neighbourhood Map

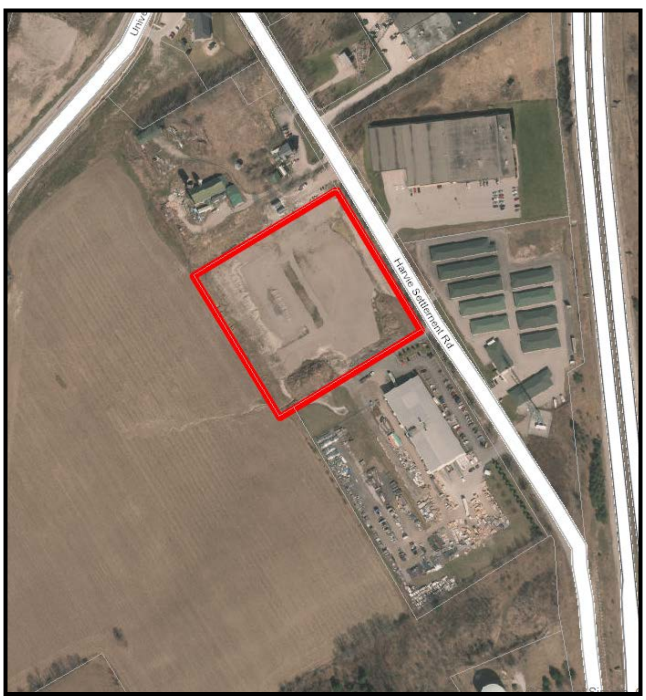


ADDITIONAL MAPS AND PHOTOS
Conceptual Lotting Map



Orillia Site #2
ADDRESS: Harvie Settlement Rd, Orillia





Nearest Intersection	University Ave & Harvie Settlement Rd
Municipality	City of Orillia
Asking Price	$680,800
Asking $/Acre	$114,806 per acre
Listing Status	Expired Listing
Listing Contact	Lauren Doughty 416-495-6223 Expired Listing Agent
Owner	Toromont Industries Ltd.
PIN #	585720199

SITE INFORMATION

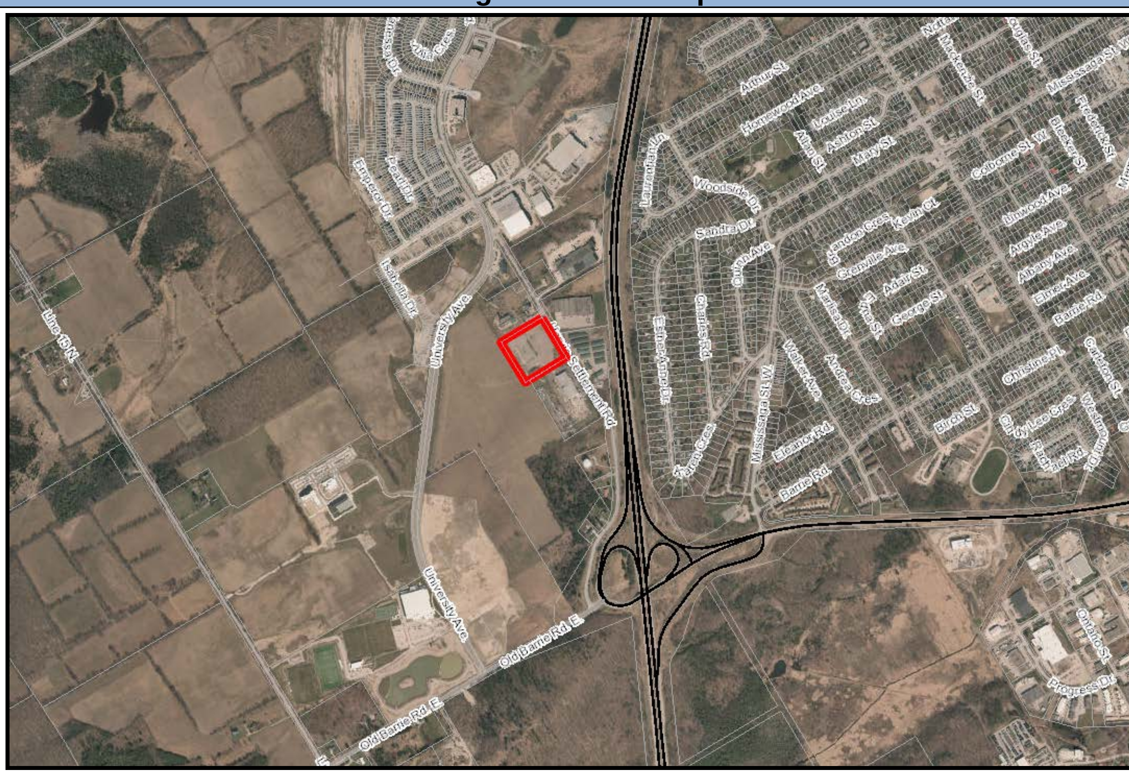
Lot Area (acres)	5.93	**Services Available**	Water, Sanitary, Hydro, Gas

COMMENTS		
Location	Located within a small pocket of industrial uses on the fringe of newly developing lands to the west of Highway 11. This property is bordered by proposed employment lands to the north and west. To the south and east are older industrial facilities.	
Land Use	Official Plan: Business Park / Industrial Zoning: M1-4(H) – Special Industrial Exception 4 The Business Park / Industrial designation allows for a range of light industrial and business park uses. The M1 zoning designation provides for business park uses with emphasis on research and development type uses such as a data centre. The proposed BUCC facility would be likely permitted within the M1 zoning designation. Outside storage of finished manufactured goods only are permitted. The Exception 4 provides for a heavy equipment sales establishment which was the intended use of the current owner.	
Site Description	Infill parcel of land that is cleared and has had significant fill and grading works completed. The elevation of the area slopes downward from Harvie Settlement Road to the west. This site is generally level over a majority of the site but slopes downward at its western boundary.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	Multiple
	Fiber Optic	Bell is available to or is nearby this site
	Hydro Supply	44 kV in Area
	Distance to Rail Line	Remote
	Distance to Major Highway	150 m to Hwy 11
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	No
	Natural Buffer	No

ADDITIONAL MAPS AND PHOTOS

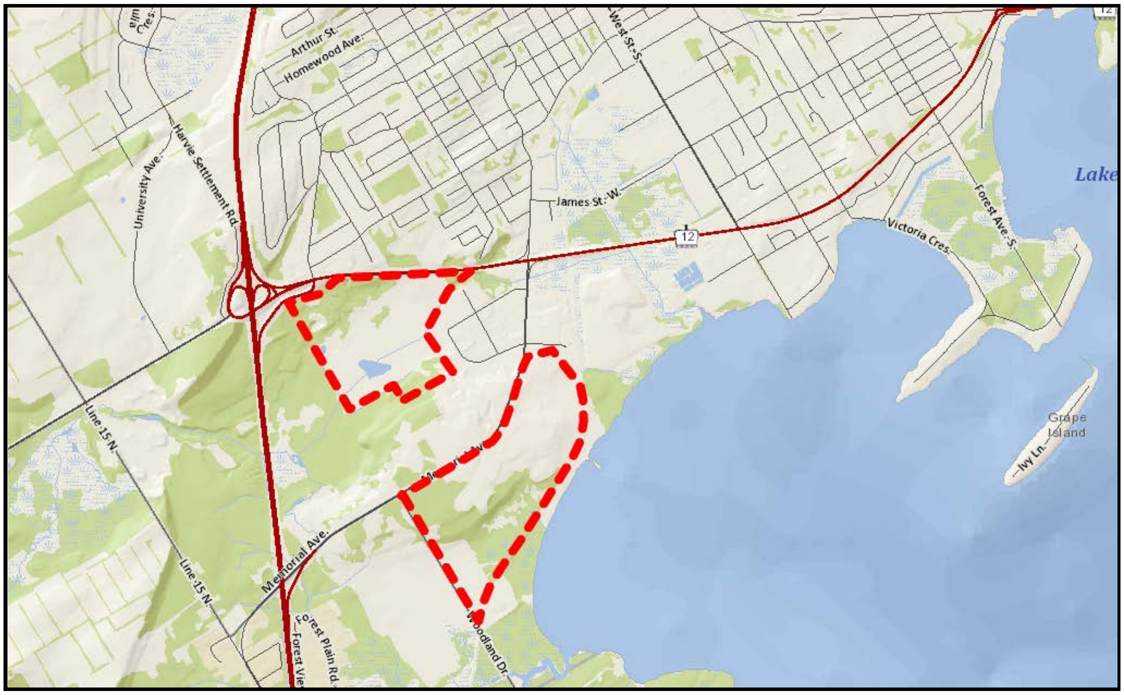
Site Photo

Neighbourhood Map



Orillia Site #3
ADDRESS: Infrastructure Ontario Lands (Near OPP Headquarters), Orillia

The provincial government owns large parcels of land at the southern limit of Orillia. The properties include the former Huronia Regional Centre and lands adjoining and including the OPP Headquarters. We are unaware if these lands have been deemed surplus. Any sale of these sites would need to go through Infrastructure Ontario's asset disposition procedures which can be onerous.



Nearest Intersection	Memorial Ave & Highway 12
Municipality	City of Orillia
Asking Price	n/a
Asking $/Acre	n/a
Listing Status	Not openly offered for sale.
Listing Contact	Infrastructure Ontario
Owner	Infrastructure Ontario
PIN #	585720345 & 585680003 (Larger Parcels)

SITE INFORMATION

Lot Area (acres)	Variable	**Services Available**	Water and sewer at property limits.

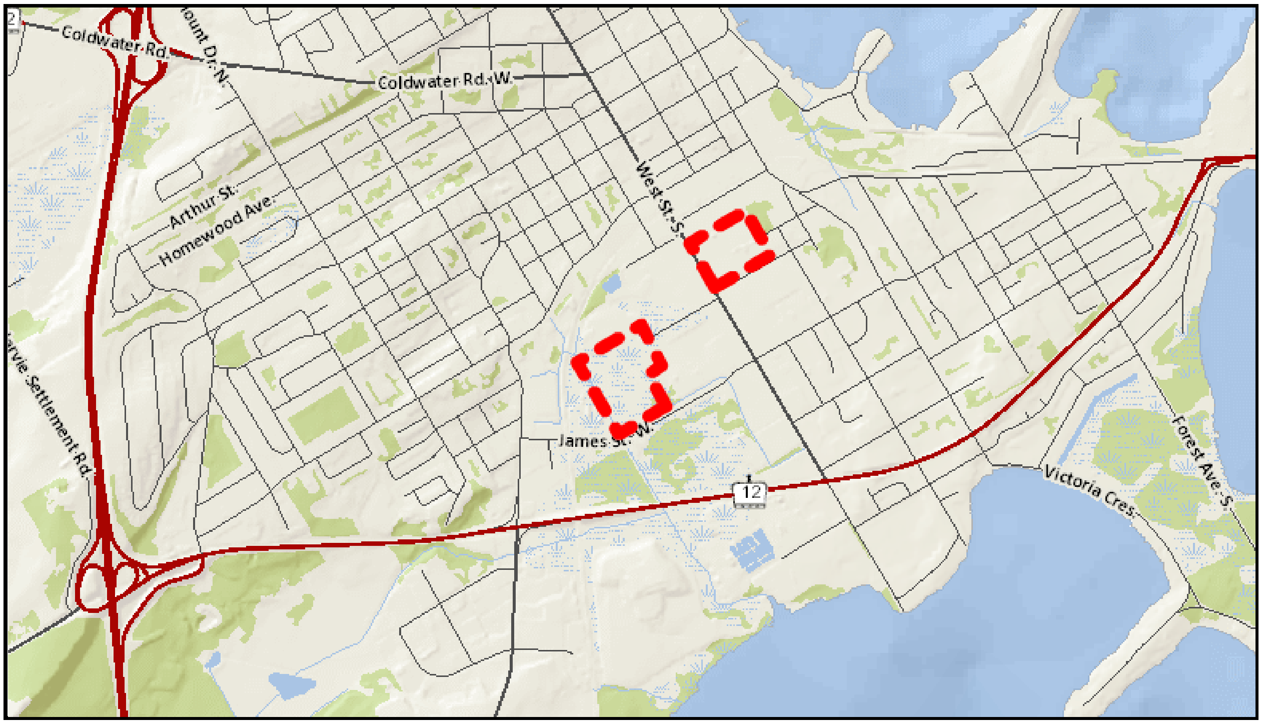
<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">Located at the southern limit of the City of Orillia. These large parcels include the former Huronia Regional Centre and lands adjacent to the OPP Headquarters.

This area is developed with a mix of institutional, light industrial and service commercial uses.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Major Institutional & EP
Zoning: CF –Community Facility & EP

The lands are zoned for institutional uses with a large portion of environmental protection. The proposed BUCC may represent a permitted Public Use.</td></tr>
<tr><td>Site Description</td><td colspan="2">The large parcels of land in this area include a mix of improved and vacant lands. A large portion of the northerly site is low lying. The Huronia Regional Centre Site is substantially improved and includes some vacant forested lands.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>Variable</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Unknown</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>0.2 to 2 km to Hwy 11</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>Unknown</td></tr>
<tr><td>Improved</td><td>Yes</td></tr>
<tr><td>Severable</td><td>Would require a severance.</td></tr>
<tr><td>Natural Buffer</td><td>Potentially</td></tr>
</table>

Orillia Site #4
ADDRESS: West Street & James Street Area, Orillia

This is an older industrial area with a few large vacant parcels that may be suitable for the BUCC site. The properties are not actively listed but they may provide an opportunity if sites are actively pursued. This area has a mix of industrial and service commercial uses but does have significant outside storage.



Nearest Intersection	James Street and West Street Area
Municipality	City of Orillia
Asking Price	Estimated to be under $115,000 per acre.
Asking $/Acre	n/a
Listing Status	Not actively marketed but may provide opportunity.
Listing Contact	Will require owners to be contacted directly.
Owner	FLSMIDTH LTD., Wide Flange Inc. & Francoz Trio Holdings Limited
PIN #	Part of 586430687 & 586710099

SITE INFORMATION

Lot Area (acres)	Various (5 to 20 acres Possible)	**Services Available**	Water, Sanitary, Hydro, Gas in Area

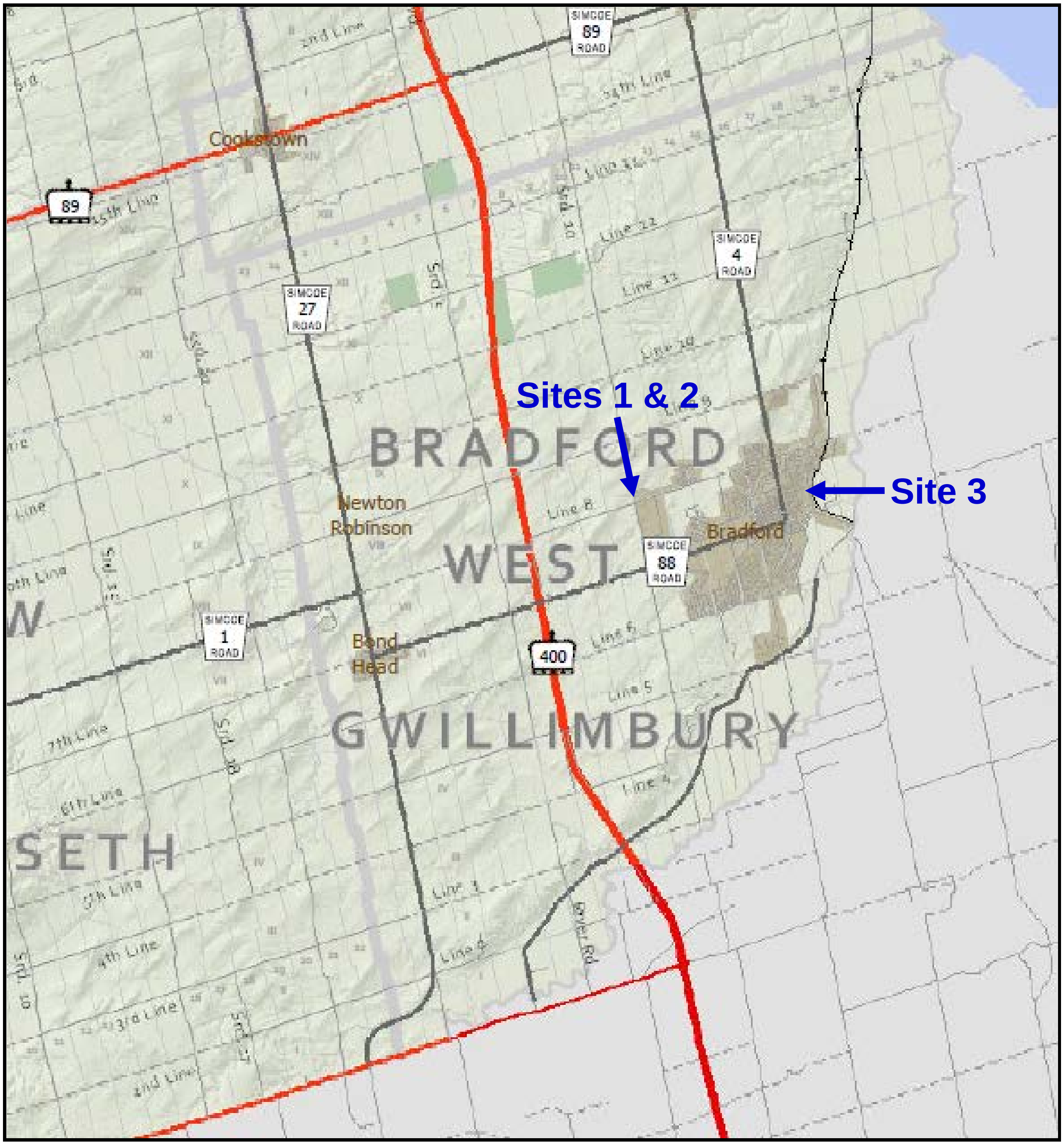
COMMENTS		
Location	This is an older industrial area that is now comprised of mainly service commercial uses such as auto dealerships along West Street with some light and general industrial uses intermixed. Some outside storage occurs in this neighbourhood.	
Land Use	Official Plan: Light Industrial Services, Intensification Area, EP Zoning: M3-5 (H), M3-4 & EP-1 (M3 – General Industrial) This zone permits a relatively narrow range of industrial uses. A rezoning may be required to provide for the proposed BUCC facility. The zoning also allows for outside storage which is occurring in the surrounding area.	
Site Description	Some of these sites are cleared and level former industrial sites that may be contaminated. Other vacant lands are forested and may include some low lying areas. Overall this neighbourhood has some concerns regarding topography and environmental issues.	
Other Criteria	Interior / Corner	Interior or Corner
	Road Frontages	1 to 2
	Access Routes	Multiple
	Fiber Optic	Bell fibre nearby
	Hydro Supply	44 kV in Area
	Distance to Rail Line	Remote
	Distance to Major Highway	2.8 km +/- to Hwy 11
	Greenfield / Infill	Infill
	Brownfield	Potentially
	Improved	No
	Severable	Would need to be severed and/or assembled.
	Natural Buffer	No

ADDITIONAL MAPS & PHOTOS

Site Photo (Westerly James St Site)

Site Photo (Easterly West St & Cochrane St Site)

TOWN OF BRADFORD WEST GWILLIMBURY



General Overview

Bradford is the largest serviced community within the municipality of Bradford West Gwillimbury which has a population of 28,077 according to 2011 census. The Town of Bradford West Gwillimbury is situated at the southern boundary of the County of Simcoe bounded by the Region of York to the immediate south. The community of Bradford enjoys close proximity to the GTA and is considered highly suitable for commuters. Growth within the community was somewhat limited in the past due to servicing constraints however recent service expansion has allowed for relatively rapid residential growth.

Infrastructure:

The community of Bradford is fully serviced. Recent servicing expansion has allowed for development to proceed which has occurred relatively rapidly. Availability of serviced industrial land is limited and not expected to increase until larger designated lands are developed and serviced. Proposed future serviced employment lands are situated in the northwest corner of the community.

Rogers reportedly provides access to fibre optic networks through a large majority of the community and is available to or nearby all sites identified. Hydro is provided by Powerstream.

Transportation

The community of Bradford is primarily accessed from County Road 88 via Highway 400. County Road 88 runs through the community and continues as Yonge Street into East Gwillimbury and Newmarket. Secondary access to the community is provided by a number of County Roads. The primary access route between the Barrie and Bradford is Highway 400. Secondary access is available from County Roads such as Yonge Street (County Road 4), County Road 10 and County Road 27, all north-south roads leading from Barrie.

Hydro Control Centre to Community Limits

Primary Route	36 km +/- (22min)
Secondary Route	40 km +/- (35mn)

Development Activity / Charges

Bradford has experienced substantial residential growth with a large number of new subdivisions actively development. New commercial development has occurred along Holland Street (County Road 88) and is primarily in the form of big box retail centres and medium sized commercial plazas. New industrial development has been limited with little vacant serviced industrial land available.

Development Charges (Effective Jan 1, 2015)

Industrial DC	$19.34 per sq.ft.
Institutional DC	$19.34 per sq.ft.

Tax Rates (Effective 2014)

Industrial (New Construction)	2.663314%
Vacant/Excess Industrial Land (New Construction)	1.731154 %

Land Use

The Town's Official Plan features a number of employment based designations with most lands designated Industrial and Industrial/Commercial. These designations would support the proposed BUCC use. The available sites appear to be zoned M1 (General Employment) and M2 (Prestige Employment). The zoning by-law does not specifically identify the subject use.

Additional land use information is provided in the detailed site write-ups.

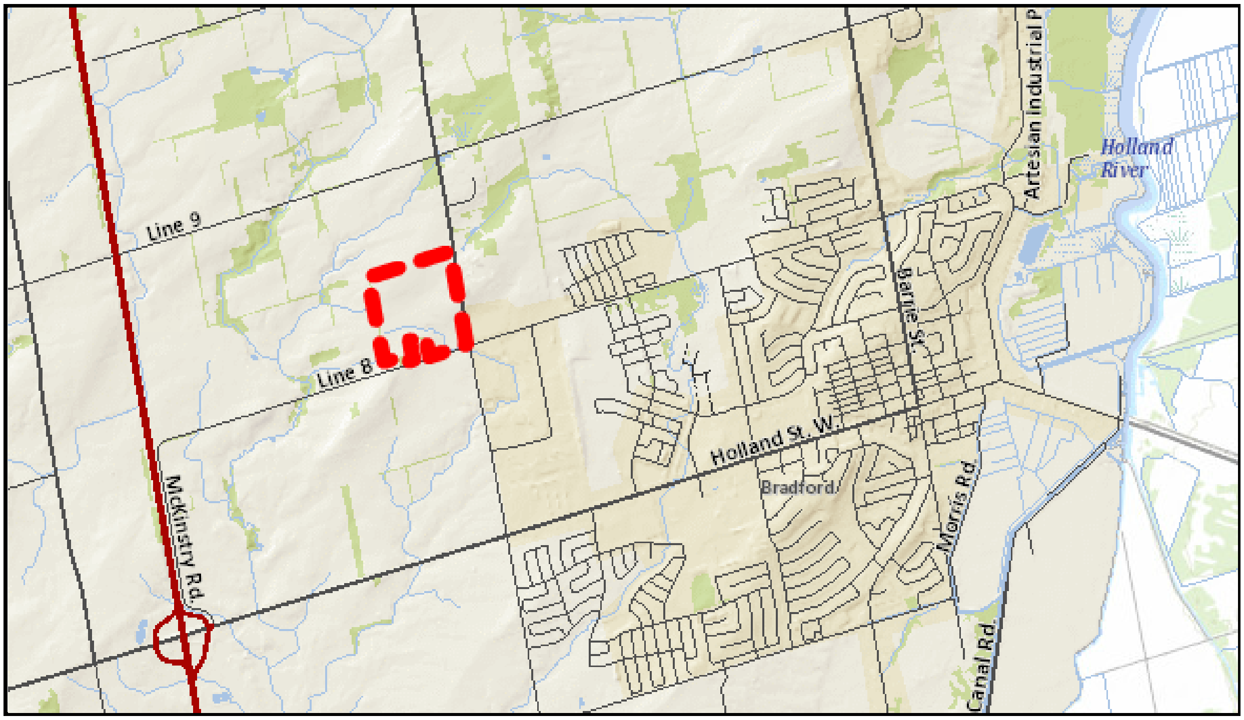
Recommended Site Summary Table:

Town	Bradford		
Site # / Ranking	**B1**	**B2**	**B3**
Location	3100 10th Sideroad	3004 Line 8	144 Dissette Street
Site Characteristics			
Size	25 acres (78.9 acre larger parcel)	51.12	6.86
Interior / Corner	Corner	Interior	Interior
Road Access Routes	Multiple	Multiple	Multiple
Road Frontage #	2	1	1
Sanitary Services	Yes - Nearby	Yes	Yes
Water Services	Yes - Nearby	Yes	Yes
Fiber Optic	Nearby	Nearby	Nearby
Hydro Supply	44 kV & 13.8 kV	44 kV & 13.8 kV	44 kV & 13.8 kV
Greenfield / Infill	Greenfield	Greenfield	Infill
Brownfield	No	No	No
Improved	No	No	Yes
Natural Buffer	No	No	No
Site Land Use (Zoning)	M1*1 , M1*2, OS, A*18 (M1 - General Industrial)	M1*8(H1), M1*9 (H1), OS (M1 - General Industrial)	M2*1 - Prestige Employment
Surrounding Use Type*	Ind; Ru	Ind; Res; Rural	Ind; Res; SC
Distance to Rail Line	4 km +/-	4 km +/-	Ind; Res; SC
Distance to Major Highway	2.5 km to Hwy 400	2.5 km to Hwy 400	Remote
Availability			
MLS / Private / Government	Active Listing	MLS - Active Listing	MLS - Active Listing
Asking Price	$315,000 per acre (Based on 25 acres)	$7,995,000 $156,396 per acre	$3,900,000 $568,513 per acre
Contact	John Powell (Colliers)	John Powell (Colliers)	Andrew Suhr & Max Simirnis (Cushman & Wakefield)
Contact #	416-791-7235	416-791-7235	416-756-5458 & 5407

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Bradford Site #1
ADDRESS: 3100 10th Sideroad, Bradford

Listing of a large parcel of development land located at the northwest corner of 10th Sideroad and Line 8. This property was designated for industrial / employment uses in OPA #9. The parcel has a total area of 98 acres, however the listing agent has indicated that a 25 acre parcel could potentially be severed and sold separately. The Town has not confirmed if this is indeed the case. Consideration of the larger development parcel may be necessary.



Nearest Intersection	10th Sideroad & Line 8
Municipality	Town of Bradford West Gwillimbury
Asking Price	$7,875,000
Asking $/Acre	$315,000 per acre
Listing Status	Active Listing
Listing Contact	John Powell (Colliers) 416-791-7235
Owner	Interphase Development Inc.
PIN #	Part of 580340108

SITE INFORMATION

Lot Area (acres)	25 acres	**Services Available**	Water, Sanitary, Hydro and Gas are reportedly nearby but likely need extending.

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located at the northwestern limit of the Bradford urban boundary. Existing industrial development is present to the east. To the north, south and west are agricultural lands not within the Bradford urban boundary at this time.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial Special Policy Area
Zoning: M1*1 & M1*2, OS & A*18 (Larger Parcel)

This site was redesignated as Industrial Special Policy Area in OPA #9. This OPA identifies the subject is intended for large lots to accommodate large manufacturing and assembly type uses. The site specific zoning General Industrial Exception 1 and 2 provides for a range of uses primarily related to clean industrial uses. Although likely it is not certain that the proposed BUCC facility would be permitted on this site.</td></tr>
<tr><td>Site Description</td><td colspan="2">This is part of a large Greenfield site that is currently cleared agricultural land. The larger site slopes significantly downward from north to south.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner</td></tr>
<tr><td>Road Frontages</td><td>2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to the site or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44 kV & 13.8 kV</td></tr>
<tr><td>Distance to Rail Line</td><td>4 km +/-</td></tr>
<tr><td>Distance to Major Highway</td><td>2.5 km to Hwy 400</td></tr>
<tr><td>Greenfield / Infill</td><td>Greenfield</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Needs to be severed and possibly serviced</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

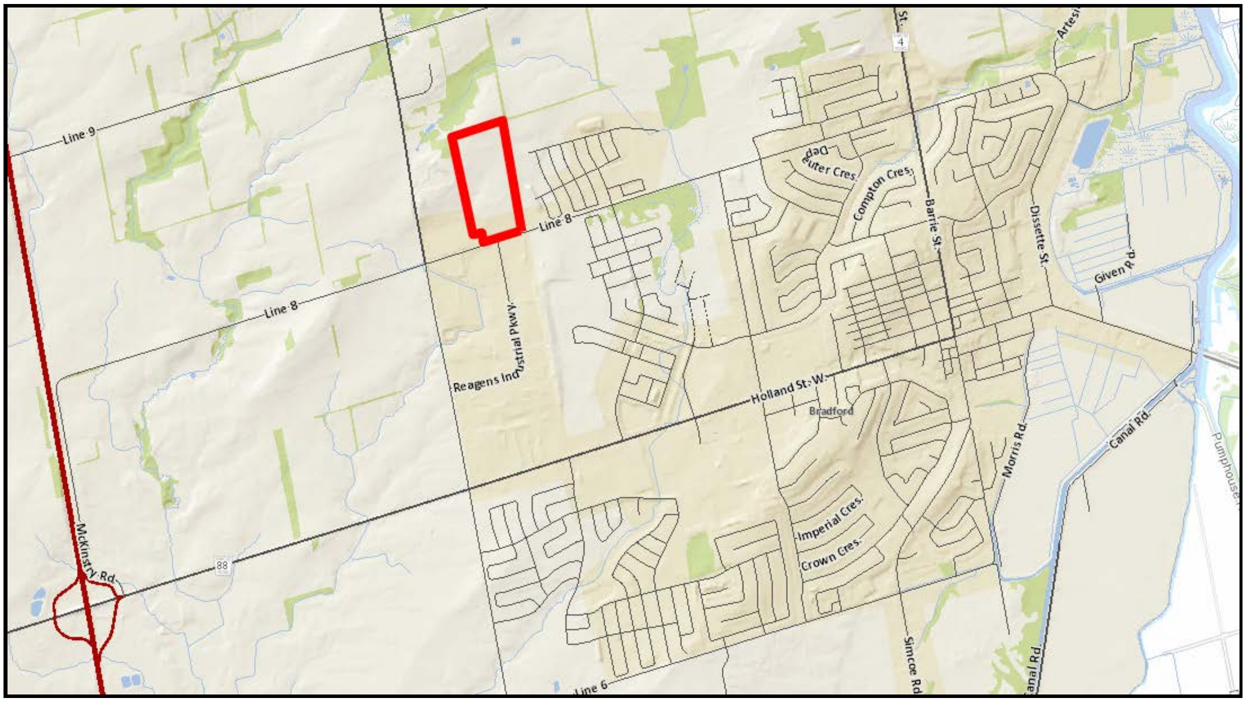
ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

Bradford Site #2
ADDRESS: 3004 Line 8, Bradford

Large parcel proposed for development as a business park. This site would require the extension of services and an internal road but may give some opportunity to create a site with the balance being surplus land that could be sold. The creation of a 5 to 10 acre site on this property will likely require significant effort including taking the site through the development process.



Nearest Intersection	10th Sideroad & Line 8
Municipality	Town of Bradford West Gwillimbury
Asking Price	$7,995,000
Asking $/Acre	$156,396 per acre
Listing Status	Active Listing
Listing Contact	John Powell (Colliers) 416-791-7235
Owner	Bradvit Holdings Inc
PIN #	580330477

SITE INFORMATION			
Lot Area (acres)	51.12 acres	**Services Available**	Water, Sanitary, Hydro, Gas at/near frontage but likely need extending.

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the northwestern limit of the Bradford urban boundary. This site is in the transition area with residential to the east and industrial to the west. Development of the site would require the extension of Reagens Industrial Parkway which is a small industrial park on the south side of Line 8.

Immediately surrounding this large development parcel is industrial uses to the south and west, agricultural to the north and new residential to the east.

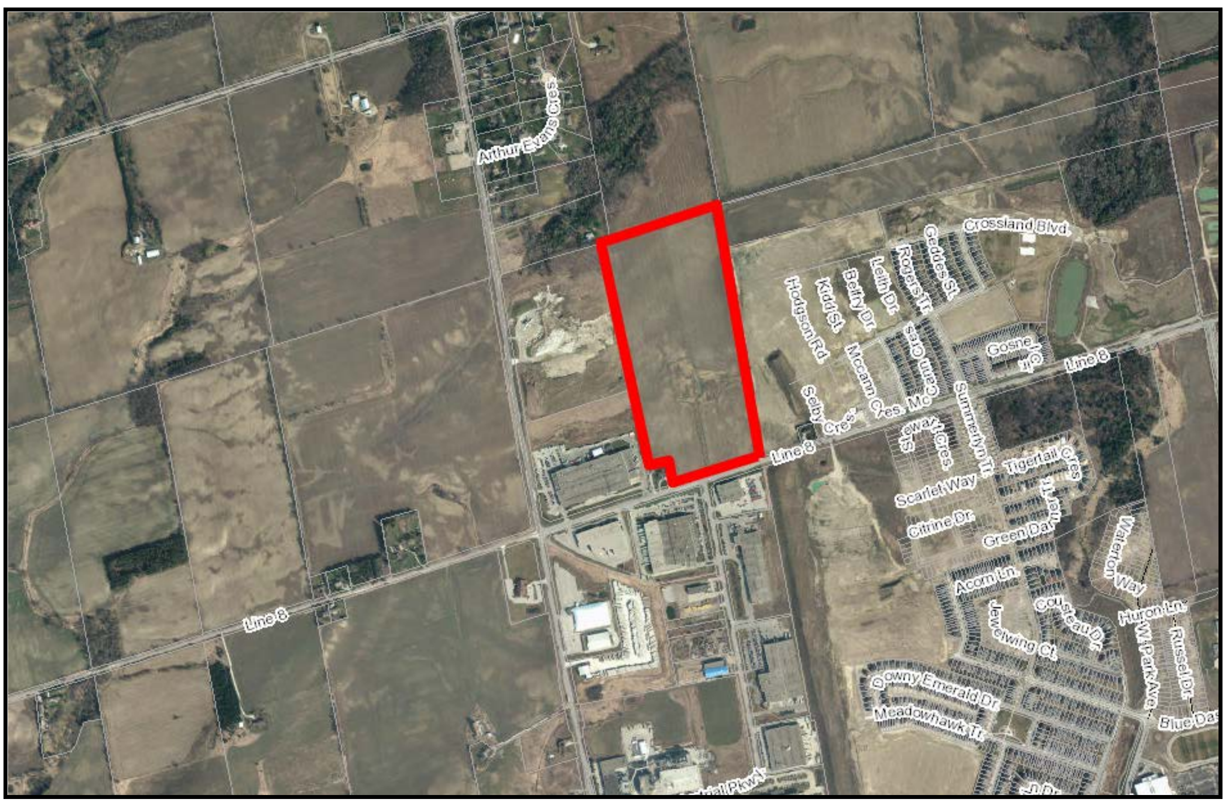
The proposed Highway 400 / 404 link highway is to run along the northern limit of this property. There is no commitment for the actual construction of this link road.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial & Industrial/Commercial
Zoning: M1*9(H1), M1*8(H1), OS.

The applicable Official Plan and Zoning would likely provide for the proposed BUCC facility. Some outside storage is permitted in the surrounding area.</td></tr>
<tr><td>Site Description</td><td colspan="2">This is a part of a large greenfield site that is cleared agricultural land. The site has a significantly rolling topography, sloping overall upwards from its road frontage to the rear.</td></tr>
<tr><td rowspan="13">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>1</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to the site or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44 kV & 13.8 kV</td></tr>
<tr><td>Distance to Rail Line</td><td>4 km +/-</td></tr>
<tr><td>Distance to Major Highway</td><td>2.5 km to Hwy 400</td></tr>
<tr><td>Greenfield / Infill</td><td>Greenfield</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Needs to be severed and possibly serviced.</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

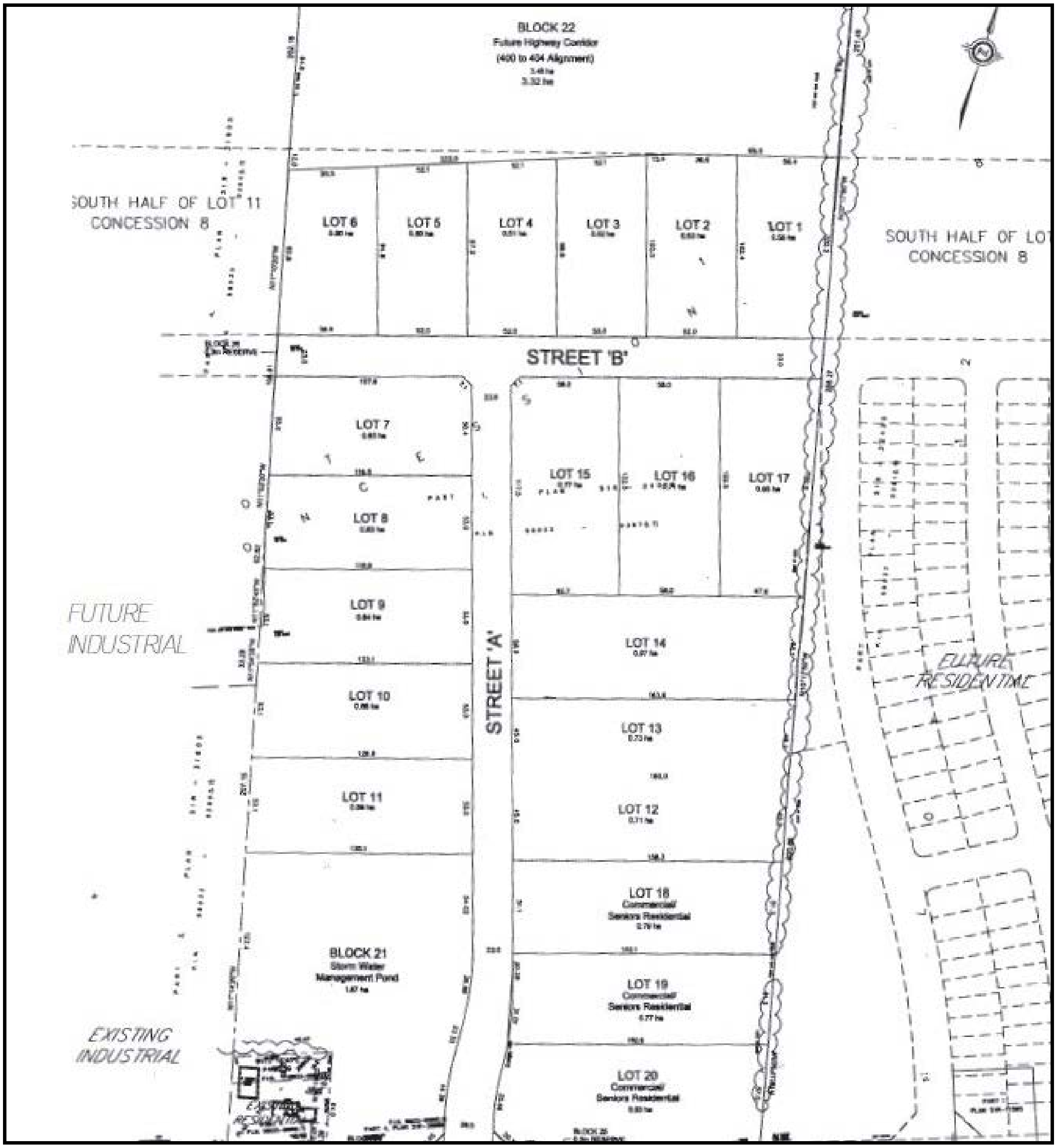
ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

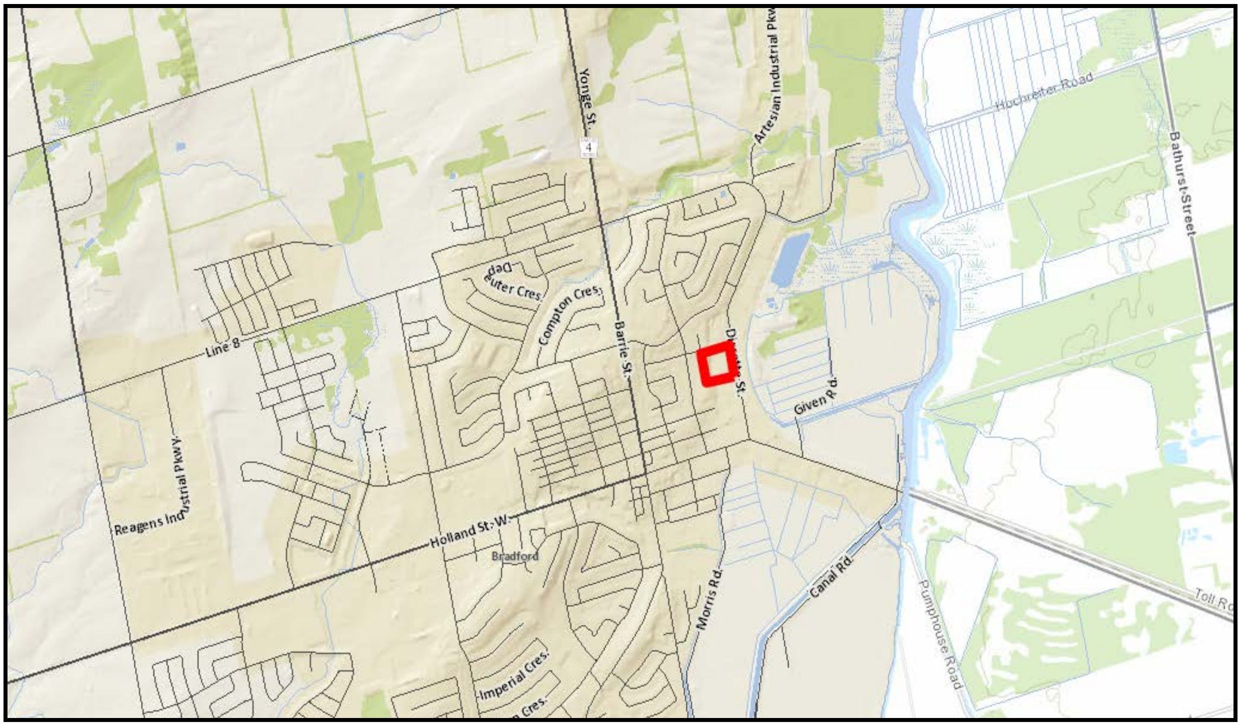


Proposed Lotting Plan



Bradford Site #3
ADDRESS: 144 Dissette Street, Bradford

Improved property located near the eastern limit of Bradford. This property is within an established corridor comprised of a mix of service commercial and industrial uses. The GO Train commuter rail line is nearby. The listing agent has indicated that a development charge credit of roughly $800,000 is potentially available.



Nearest	10th Sideroad & Line 8
Municipality	Town of Bradford West Gwillimbury
Asking Price	$3,900,000
Asking	$568,513 per acre
Listing	Active Listing
Listing	Andrew Peter Suhr 416-756-5458 Max Smirnis (Cushman & Wakefield) 416-756-5407
Owner	Dissette Developments Ltd.
PIN #	580240169

SITE INFORMATION

Lot Area (acres)	6.86 acres	**Services**	Water, Sanitary, Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the eastern limit of Bradford within an area comprised of a mix of industrial and service commercial uses. Dissette Street is utilized as a by-pass road proving access to Hwy 400 and 10th Sideroad while avoiding the downtown core. As a result relatively high traffic volumes are experienced. The industrial uses are generally older with current demand more related to service commercial uses. The GO Train line and station are located in close proximity.

Immediately surrounding the property are a commercial plaza to the south, a school to the west, GO Line slightly to the east and vacant industrial land to the north. The lands to the west are elevated and look down on this site.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial/Commercial
Zoning: M2*1- Prestige Employment

The Official Plan designation allows for a “full range of light industrial and office uses”. The zoning also provides for a range of light industrial and service commercial type uses. The proposed BUCC facility would likely be permitted on this site but may require an amendment.</td></tr>
<tr><td>Site Description</td><td colspan="2">This site is improved with a dated warehouse previously utilized as a food processing plant. The building is approximately 42,000 sq.ft.. The site is mostly cleared and level at the front but slopes abruptly upward at the rear. The use of the property as a food processing plant would not typically result in contamination. The listing agent has indicated that any contamination has been dealt with.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>1</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to the site or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44 kV & 13.8 kV</td></tr>
<tr><td>Distance to Rail Line</td><td>55m - GO Train</td></tr>
<tr><td>Distance to Major Highway</td><td>6 km to Hwy 400</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>Yes</td></tr>
<tr><td>Severable</td><td>No</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

ADDITIONAL MAPS & PHOTOS

Site Photo

Site Photo

ADDITIONAL MAPS & PHOTOS

Neighbourhood Map

TOWN OF COLLINGWOOD

General Overview

Collingwood has seen a significant shift towards the tourist-related service. Large expansions of Blue Mountain Ski Resort into a year round destination and amenity provided by Georgian Bay and the Niagara Escarpment have combined to make Collingwood a popular Tourism centre. Collingwood is considered a mid to large retail centre that services the community and surrounding areas, particularly the Town of Blue Mountains to the west. Collingwood continues to have a moderate although somewhat smaller manufacturing base. The 2011 census identifies the population of Collingwood to be 19,241.

Infrastructure:

The Town of Collingwood is a fully serviced community with two main serviced business / industrial park areas. These areas include a pocket of development at the southeast corner of the community and a pocket of development along Mountain Road near the west limit of the community. These areas are serviced with water, sewer, hydro and are reported to have access or nearby access to Rogers fibre optic. Hydro services are provided by Collus Powerstream.

Transportation

The Town of Collingwood is primarily accessed by Hwy 26 which runs to the City of Barrie to the east and Owen Sound to the west. A significant upgrade to Hwy 26 was recently completed which bypassed Wasaga Beach and a relatively slow section of the previous highway. These changes have improved the access to Collingwood. Alternate access to the community from the City of Barrie can be achieved from County Road 90 and secondary roads but this route would be more indirect.

Hydro Control Centre to Community Limits

Primary Route	50 km +/- (40 min)
Secondary Route	50 - 60 km +/- (50 to 55 min)

Development Activity / Charges

The community has experienced moderate growth in recent years. New development is primarily residential with some standard subdivisions at the southern portion of the Town and a number of waterfront retirement oriented developments along the shore line. Commercial growth has occurred with some new retail along First Street that is primarily tourism oriented and new format retail near the west limit of the community. Industrial growth has been limited with a number of large manufactures closing in recent years.

Development Charges (Effective Jan 1, 2015)

Non-Residential DC	$5.63 per sq.ft.
Black Ash Creek Area Charge	$5,045 per net developable acre

The Mountain Road Industrial Area is within the Black Ash Creek Area.

Tax Rates (Effective 2014)

Industrial (New Construction)	3.410246 %
Vacant/Excess Industrial Land	2.216660 %

Land Use

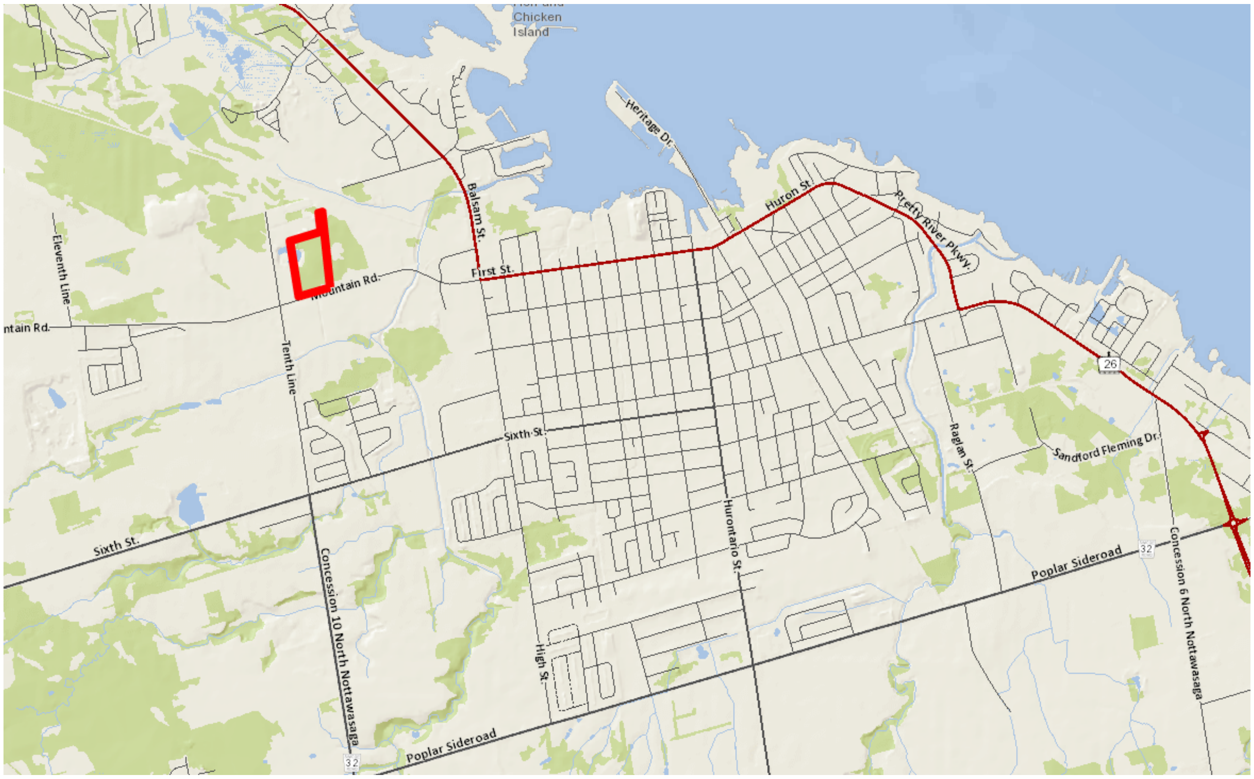
The most likely Official Plan designations that would allow for the BUCC use are Industrial and Light Industrial. The zoning by-law does not specifically outline the subject BUCC use. Most industrial zones, excluding M3 – Extractive Industrial, would likely allow for the proposed use.

Recommended Site Summary Table:

Town	Collingwood		
Site # / Ranking	**C1**	**C2**	**C3**
Location	185 Mountain Road	Raglan Street & Poplar Sideroad	Other Mountain Road Potential Oportunities
Site Characteristics			
Size	20 acres	25.6 acres	Various
Interior / Corner	Interior	Corner	Interior
Road Access Routes	Multiple	Multiple	Multiple
Road Frontage #	1	2	1
Sanitary Services	Yes	Yes	Yes
Water Services	Yes	Yes	Yes
Fiber Optic	Nearby	Nearby	Nearby
Hydro Supply	44 kV & 4160/2400 V	44 kV & 4160/2400 V	44 kV & 4160/2400 V
Greenfield / Infill	Infill	Greenfield	Infill
Brownfield	No	No	No
Improved	No	No	Partially
Natural Buffer	Yes (Forested)	Partial	Yes (Forested)
Site Land Use (Zoning)	M5 (H11) - Industrial Park	M4-H12 - Business Park, EP - Environmental	M5 - Industrial Park (M5 (H11),M5, M5-5)
Surrounding Use Type*	Ind	Ind, EP, I	Ind, SC
Distance to Rail Line	Remote	Remote to Active Line	Remote
Distance to Major Highway	Remote	Remote	Remote
Availability			
MLS / Private / Government	MLS - Expired Listing	MLS - Active Listing	-101 Mountain Rd - Active - South of Mountain Rd not currently offered
Asking Price	$1,900,000 $95,000 / acre	$4,900,000 $191,406 / acre	Estimated in the range of $90,000 to $150,000 / acre
Contact	Joe Gardhouse (Previous Listing Agent)	Robert Archambault	101 Mountain Road John Edwards
Contact #	705-445-5640	416-806-2002	J. Edwards - 416-840-6300

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Collingwood Site #1
ADDRESS: 185 Mountain Road, Collingwood



Nearest Intersection	Mountain Road & Tenth Line
Municipality	Town of Collingwood
Asking Price	$1,900,000
Asking $/Acre	$95,000 per acre
Listing Status	Expired Listing – MLS To be re-listed
Listing Contact	Joe Gardhouse 705-445-5640 guardhouse@rogers.com
Owner	960121 Ontario Inc.
PIN #	582550100 & 582550488

SITE INFORMATION

Lot Area (acres)	20	**Services Available**	Water, Sanitary, Hydro, Gas

COMMENTS		
Location	This site is located in the western portion of the Town of Collingwood, within a transitional industrial area. The immediate surrounding area is comprised of older industrial while the larger neighbourhood features commercial to the east and rural-estate properties leading to Blue Mountain to the west. To the south of the property is a large industrial facility. To the east is a large portion of vacant lands followed by a large industrial facility. To the west of the property are small industrial and service commercial properties. A small concrete plant is also found to the west.	
Land Use	Official Plan: Industrial Park Zoning: M5 (H11) – Industrial Park The subject property is identified as Industrial Park within the Town of Collingwood Official Plan. This designation provides for general and light industrial uses. Outside storage is prohibited but we note some existing sites have some yard storage present. The OP also identifies the property is within a Waste Disposal Assessment Area. The property is zoned M5 which provides for a range of industrial and business park uses. The zoning allows for outside storage of goods, such as equipment sales. The "Hold 11" identifies that a D4 study is required and possible a draft plan of subdivision is required to allow for development. The proposed BUCC facility would be likely permitted on this site.	
Site Description	The site is generally rectangular in shape and is reported to measure approximately 17.59 acres in size. The majority of the site is thickly forested and generally level. A portion at the rear appears to be a former sand pit that is now flooded.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	Multiple
	Fiber Optic	Rogers fibre available or nearby.
	Hydro Supply	44 kV & 4160/2400
	Distance to Rail Line	200 m from a former rail line now used as a trail
	Distance to Major Highway	Remote
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	Potentially
	Natural Buffer	Yes (Forested)

ADDITIONAL MAPS & PHOTOS
Site Photo from Mountain Road

Neighbourhood Map

Collingwood Site #2
ADDRESS: Raglan Street, Collingwood

Nearest Intersection	Raglan Street & Poplar Sideroad
Municipality	Town of Collingwood
Asking Price	$4,900,000
Asking $/Acre	$191,406 per acre
Listing Status	Active - MLS
Listing Contact	Robert Archambault 416-806-2002
Owner	Redleigh Holdings Inc.
PIN #	582620084

SITE INFORMATION

Lot Area (acres)	25.6 acres (12 acres +/- outside of Floodplain)	**Services Available**	Water, Sanitary, Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the southeast limit of the Town of Collingwood, within the Industrial/Business Park. The property is at the southern limit of the Collingwood Urban Boundary.

To the south of the property is rural agricultural land. To the east are Industrial lands improved with the recently constructed Georgian College South Georgian Bay Campus. A watercourse runs along a portion of the west boundary and along the northern boundary. To the north of the watercourse is a vacant parcel zoned recreational. A single family residence is also situated to the west.

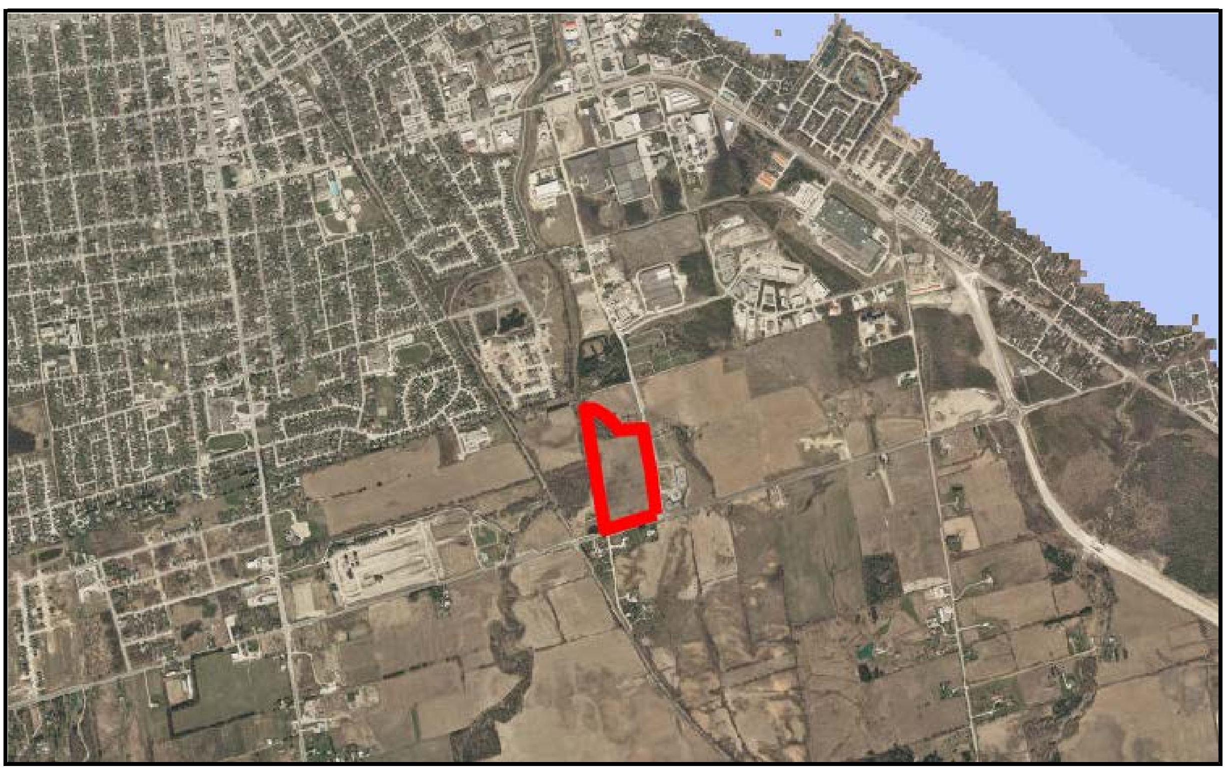
The surrounding area is primarily comprised of light industrial uses. A former ethanol processing plant is situated approximately 1.1 km to the northeast.</td></tr>
<tr><td>Land Use</td><td colspan="2">The subject property is identified as Industrial and Environmental Protection within the Town of Collingwood Official Plan. The property is zoned M4 which provides for a range of industrial and business park uses. The “Hold 12” identifies that “the adoption of a authorized by-law for a site plan control agreement” is required to allow for development. The proposed BUCC facility would be likely permitted on this site.

The northern portion of the site is subject to Nottawasaga Conservation Authority Regulation related to the flood plain for the nearby river. We have estimated the southern 12 acres +/- of the site to be outside the regulated area. Further study would be required to definitively determine the useable acreage.</td></tr>
<tr><td>Site Description</td><td colspan="2">The site is slightly irregular in shape and is reported to measure approximately 25.6 acres of which roughly 12 acres is outside of the regulated area. The majority of the site is cleared agricultural land that is relatively level. A watercourse runs through the northwest corner of the site.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner</td></tr>
<tr><td>Road Frontages</td><td>2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers fibre available or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44 kV & 4160/2400</td></tr>
<tr><td>Distance to Rail Line</td><td>150 m from a Former rail line now used as a trail</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Greenfield</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Potentially</td></tr>
<tr><td>Natural Buffer</td><td>Partial</td></tr>
</table>

ADDITONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map



Collingwood Site #3
ADDRESS: Mountain Road Potential Opportunities, Collingwood

A significant portion of Industrial lands along Mountain Road are large vacant sites that are thickly forested. A large parcel at 101 Mountain Road is listed but includes a larger facility that has substantial surplus land which may be severable. The entire property is being marketed by Jon Edwards of Urban Remax Toronto. We are not aware if the owner is willing to sever the vacant portion of the site but may be posible. The lands to the south of Mountain Road are not actively listed. Potential may exist for a site in this area if further pursued.

Nearest Intersection	Mountain Road & Tenth Line
Municipality	Town of Collingwood
Asking Price	n/a
Asking $/Acre	Estimated to be roughly $90,000 to $150,000 per acre.
Listing Status	- 101 Mountain Rd is active (larger parcel) - Other lands not currently offered
Listing Contact	101 Mountain Road Jon Edwards 416-840-6300
Owner	Various
PIN #	582550393, 582600568, 567 & 566

SITE INFORMATION

Lot Area (acres)	Various	**Services Available**	Water, Sanitary, Hydro, Gas in area

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">Industrial lands located along Mountain Road between Tenth Line and Highway 26. This area is comprised of large manufacturing facilities and some light industrial uses in addition to significant forested vacant industrial lands.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial Park
Zoning: M5 (H11), M5 & M5-5 – Industrial Park

This area is all zoned Industrial Park with some site specific requirements or restrictions. The Industrial Park Official Plan designation does not allow for outside storage while the M5 designation allows for outside sales only. The proposed BUCC facility would be likely permitted in this area.

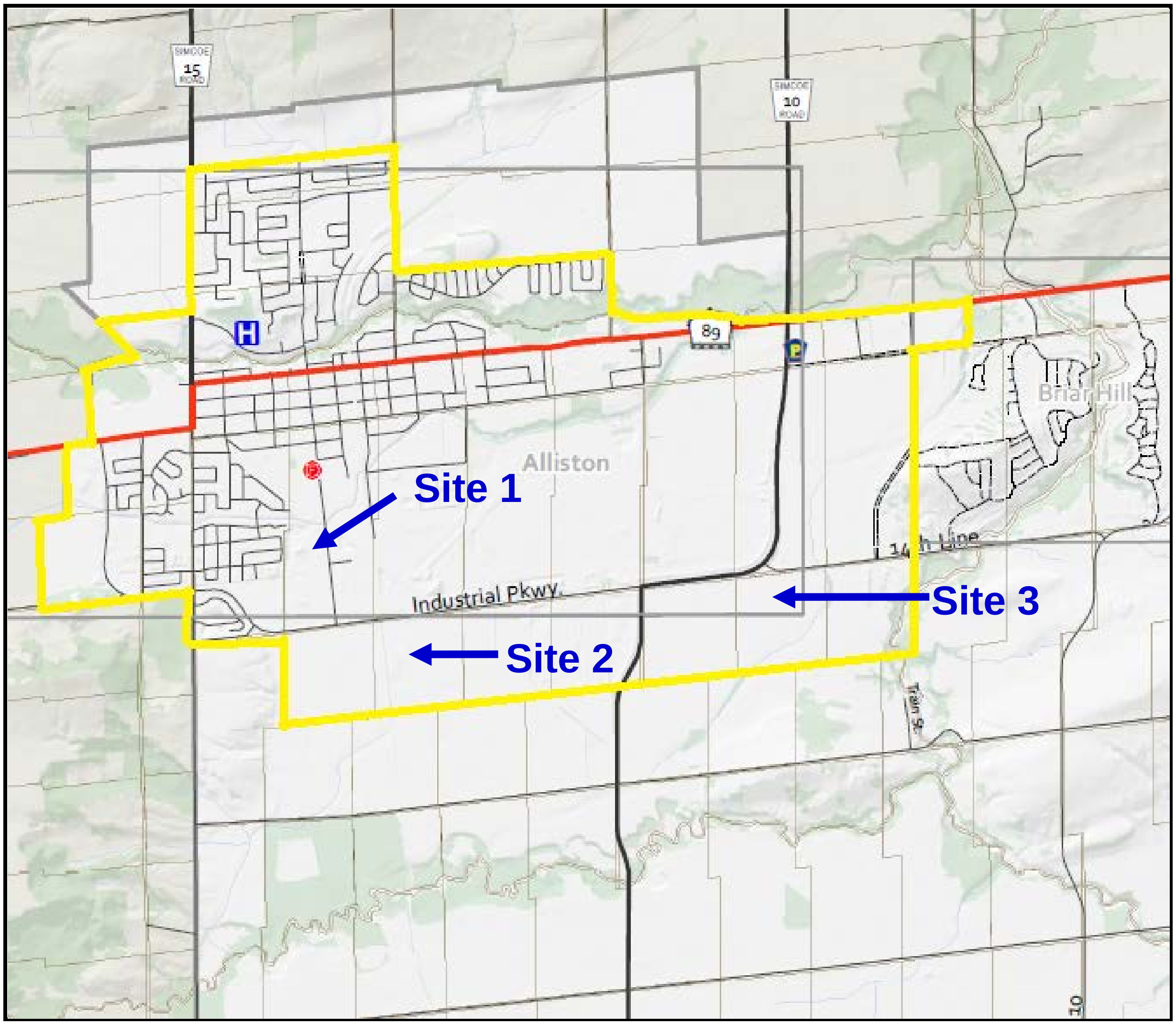
The lands within this area are partially impacted by the NVCA Regulated Area. Investigation into the actual developable acreage would be required.</td></tr>
<tr><td>Site Description</td><td colspan="2">The lands in this area are generally level and thickly forested.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>1</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers fibre available or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44kV & 4160/2400</td></tr>
<tr><td>Distance to Rail Line</td><td>A former rail line now used as a trail is nearby</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>Partially</td></tr>
<tr><td>Severable</td><td>Site would likely need to be severed</td></tr>
<tr><td>Natural Buffer</td><td>Yes (Forested)</td></tr>
</table>

ADDITIONAL MAPS & PHOTOS

Site / Area Photo

Neighbourhood Map

COMMUNITY OF ALLISTON (NEW TECUMSETH)



General Overview

Alliston is the largest serviced community within the Town of New Tecumseth. This Township includes a large agricultural industry with significant pockets of productive farmland. In addition to Alliston, the communities of Beeton and Tottenham are the other serviced communities although much smaller. The population for New Tecumseth as of 2011 (Census) is 30,234.

Alliston is considered the primary commercial and employment centre for the surrounding area. Large industry led by the Honda Manufacturing Plant provides a large employment base that has been one of the primary driving factors of growth in the community. Also significant in the area is Base Borden to the north and the proximity to the GTA which is considered within commuter distance. Economic spin off from Honda, Base Borden and the surrounding agricultural industry are all beneficial to the community of Alliston.

Infrastructure:

Alliston is a fully serviced community. Servicing constraints related to water and wastewater resulted in a period of limited growth however infrastructure expansion and agreements with surrounding municipalities allowed for additional capacity and growth to continue.

The primary employment lands within the community are along the southern and eastern limits. These lands are serviced or have services nearby.

Rogers reportedly provides access to fibre optic networks through a large majority of the community. Hydro is provided by Powerstream.

Transportation

Alliston is accessed by a good transportation network that includes Highway 89 running east to west to Hwy 400 and County Road 10 running north to south providing access to Highway 9, which once again connects to Highway 400. The primary access route between Barrie and Alliston is provided by Highway 400 and Highway 89. A number of alternative routes are also present including County Road 27, County Road 50, County Road 10 and a number of other north-south and east-west local roads.

Hydro Control Centre to Community Limits

Primary Route	37 km +/- (26 min)
Secondary Route	33 km +/- (30 min)

Development Activity / Charges

Alliston has experienced strong growth in recent years with new residential development occurring at the northern and eastern limits of the urban boundary. Industrial development has been limited with no substantial new industrial facilities other than the expansion of the Honda Plant in recent years. A large industrial subdivision is proposed for development by Walton International. This development is to occupy 155 acres and is expected to begin servicing works in 2015.

Development Charges (Effective Jan 20, 2015)

Industrial DC	$13.70 per sq.ft.
Other Non-Residential DC	$22.52 per sq.ft.

Tax Rates (Effective 2014)

Industrial	2.871885 %
Vacant Industrial Land	1.866725 %

Land Use

The Official Plan identifies the community employment and industrial lands as Employment Land 1 and Employment Land 2 with Employment Area 2 representing the majority of the newer Industrial lands. This designation would provide for the subject BUCC use. The easterly portion of the community is designated within the Alliston Industrial/Commercial Area Secondary Plan. The area under control of this secondary plan represents mostly newly developed and future developing lands.

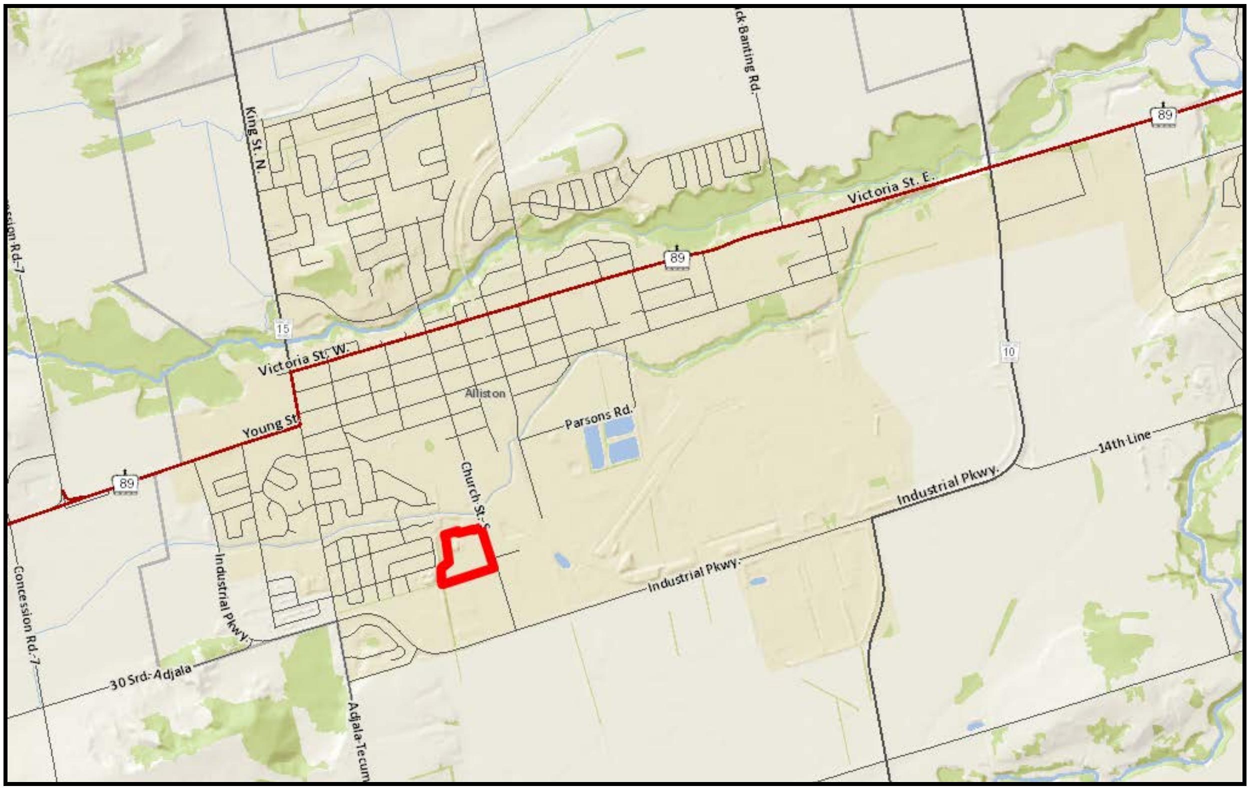
The zoning by-law identifies the majority of the lands within the south Alliston industrial area as Urban Industrial. This designation provides for a relatively limited number of uses but includes manufacturing and warehousing facilities. The zoning also allows for some heavy industrial uses. The proposed BUCC use is not clearly identified within the zoning permitted uses. A rezoning could be necessary but is likely achievable.

Recommended Site Summary Table:

Town	Alliston (New Tecumseth)		
Site # / Ranking	**A1**	**A2**	**A3**
Location	258 Church Street S	Alliston Industrial Park (Walton)	6485 14th Line
Site Characteristics			
Size	15.45	5 to 10 acres +	12.55
Interior / Corner	Interior	Interior / Corner	Interior
Road Access Routes	Multiple	Unknown	Unknown
Road Frontage #	1	Unknown	1
Sanitary Services	Yes	Yes	Yes
Water Services	Yes	Yes	Yes
Fiber Optic	Nearby	Nearby	Nearby
Hydro Supply	13.8 kV (44 kV 360m South)	44 kV to be available	44kV along Ind. Pkwy
Greenfield / Infill	Infill	Greenfield	Geenfield
Brownfield	No	No	No
Improved	No	No	No
Natural Buffer	No	No	No
Site Land Use (Zoning)	UM - Urban Industrial	UM-H5 - Urban Industrial	A1 - Agricultural
Surrounding Use Type*	Ind; Res; I	Ind; Ru	Ind; Ru
Distance to Rail Line	300 m +/-	Nearby	1.5 km +/-
Distance to Major Highway	Remote	Remote	Remote
Availability			
MLS / Private / Government	MLS - Expired Lising (Still Available)	Active Listing	MLS - Expired Listing
Asking Price	$225,000 per acre	$370,000 to $425,000 per acre	$2,500,000 $199,206 per acre
Contact	Marc Ronan (Coldwell Banker Realty)	Trevor Ellis & Benjamin Sykes (Avison Young)	Michael Saperia (The Behar Group Realty)
Contact #	905-936-4216	905-283-2329 & 2324	416-636-8898

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Alliston Site #1
ADDRESS: 258 Church Street S, Alliston



Nearest	Church Street S & Industrial Parkway
Municipality	Town of New Tecumseth
Asking Price	$3,476,250
Asking	$225,000 per acre
Listing	Expired Listing (Still Available)
Listing	Marc Ronan 905-936-4216 (Coldwell Banker Realty)
Owner	Simon Brouwer & Robert Sutherland
PIN #	581310369

SITE INFORMATION

Lot Area (acres)	15.45 acres	**Services**	Water and Sanitary Reported Available, Hydro, Gas

COMMENTS		
Location	This site is within the Alliston Industrial area at the southern limit of the community. The surrounding industrial lands are closely associated with the Honda Manufacturing Plant and are mostly transportation based such as trucking facilities. The Honda Plant is slightly east of the property. A rail line runs to the facility and through the community. Immediately surrounding this site is a residential subdivision to the west, light industrial uses to the south and east, and a church to the north.	
Land Use	Official Plan: Employment Area 2 Zoning: UM – Urban Industrial The Official Plan designation provides for light industrial and business park uses such as R&D facilities, data centres, etc and would permit the BUCC use. The zoning allows for multiple uses but does not specifically outline a use that would be highly similar to the proposed BUCC facility. The zoning allows for some heavy industrial uses.	
Site Description	The site is cleared and generally level.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	Multiple
	Fiber Optic	Rogers available to the site or nearby
	Hydro Supply	13.8 kV; 44kV is 360m to the south along Industrial Pkwy.
	Distance to Rail Line	300m to Rail Line
	Distance to Major Highway	Remote
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	Yes
	Natural Buffer	No

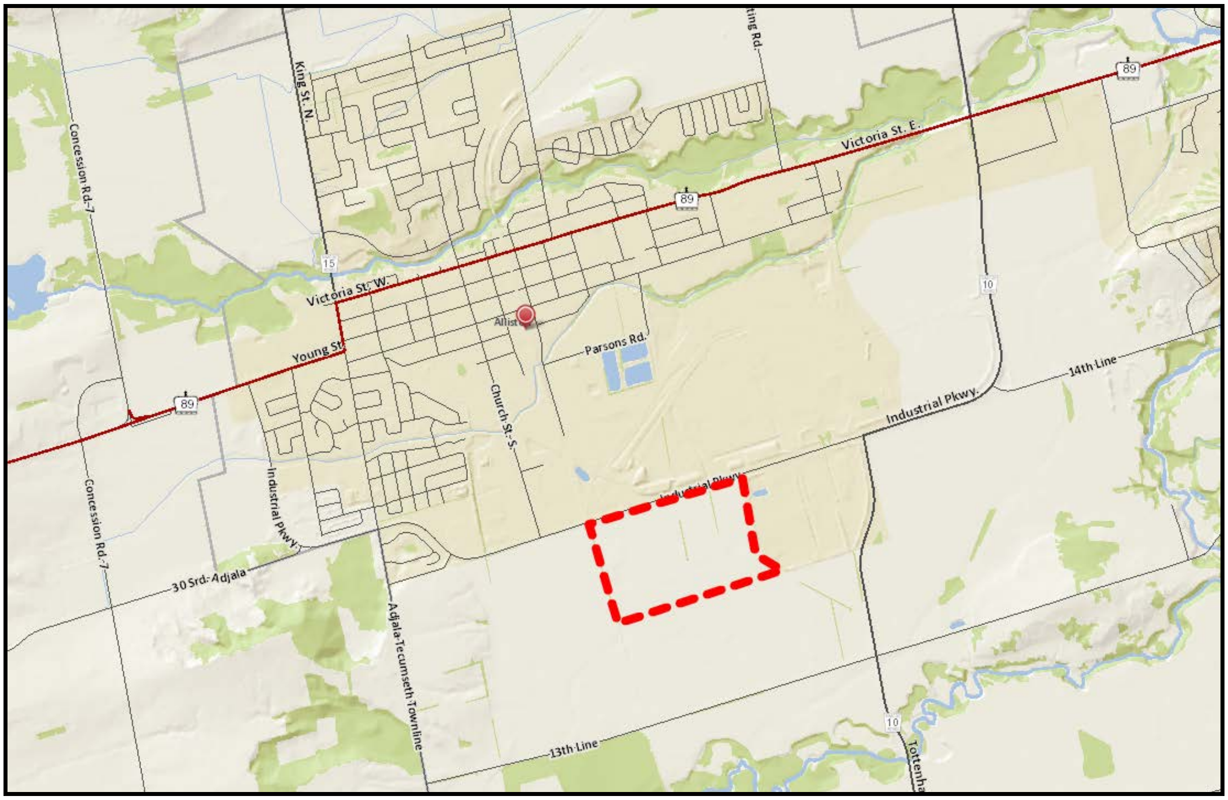
ADDITIONAL MAPS AND PHOTOS

Site Photo

Neighbourhood Map

Alliston Site #2
ADDRESS: Alliston Industrial Park, Alliston

Large industrial business park being actively marketed by Walton Development Group. The Town of New Tecumseth has indicated that this site has approvals and is expected to begin pre servicing works in 2015. The listing agent indicated that servicng will proceed in spring 2015.



Nearest	Industrial Parkway & Tottenham Rd
Municipality	Town of New Tecumseth
Asking Price	n/a
Asking	$370,000 to $425,000 per acre (Potenially lower for larger sites)
Listing	Actively Marketed
Listing	Trevor Ellis 905-283-2329 (Avison Young)
Owner	Walton Alliston Development Corp
PIN #	Part of 581460098 & 581460092

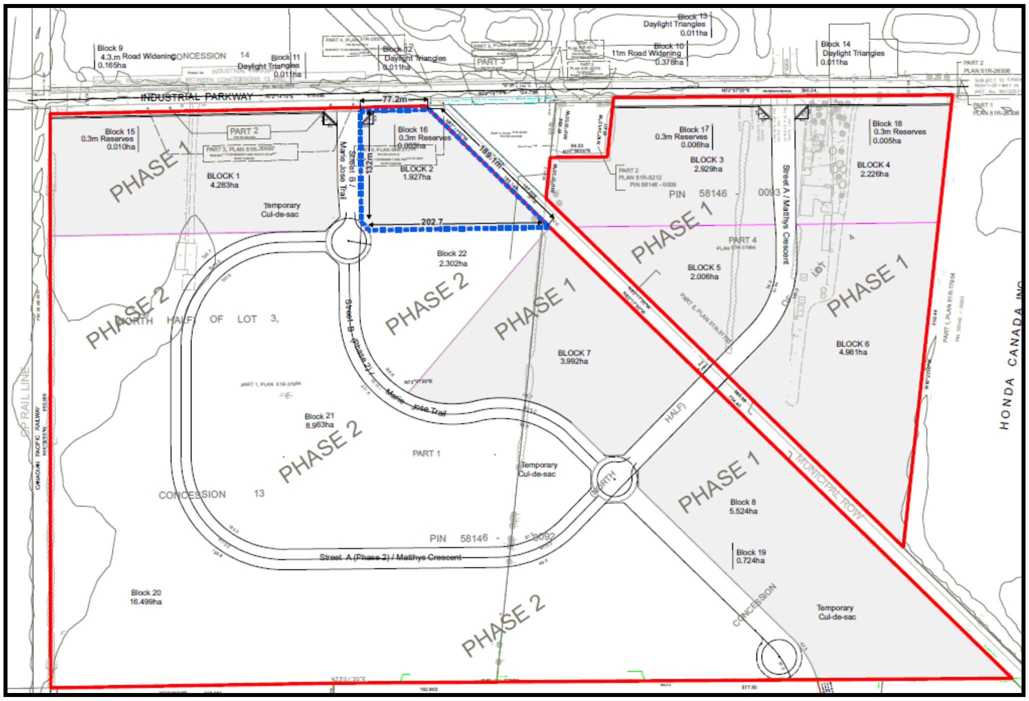
SITE INFORMATION

Lot Area (acres)	5 to 10 acres +	**Services**	Water, Sanitary, Hydro and Gas to be available.

COMMENTS		
Location	This site is within the Alliston Industrial area at the southern limit of the community. These industrial lands are to be developed into a large business park. This area is closely associated with the Honda Manufacturing Plant and is mostly developed with transportation based uses such as trucking facilities or related manufacturing. The Honda Plant is to the north of the property. A rail line runs along the west limit of the Industrial Park. Immediately surrounding this site is Honda to the north, a large industrial property to the east and vacant farm / future development land to the west and south.	
Land Use	Official Plan: Employment Area 2 Zoning: UM-H5 – Urban Industrial The Official Plan designation provides for light industrial and business park uses such as R&D facilities, data centres, etc and would permit the BUCC use. The zoning allows for multiple uses but does not specifically outline a use that would be highly similar to the proposed BUCC facility. The zoning allows for some heavy industrial uses. The holding symbol identifies that the site can be used for agricultural purposes until the removal of the symbol.	
Site Description	The site is cleared and generally level agricultural land.	
Other Criteria	Interior / Corner	Interior or Corner
	Road Frontages	Unknown
	Access Routes	Unknown
	Fiber Optic	Rogers available to the site or nearby
	Hydro Supply	44 kV to be installed when developed
	Distance to Rail Line	A rail line runs along the west limit. Sites more remote to the line will be available.
	Distance to Major Highway	Remote
	Greenfield / Infill	Greenfield
	Brownfield	No
	Improved	No
	Severable	To be severed when developed.
	Natural Buffer	No

ADDITIONAL MAPS

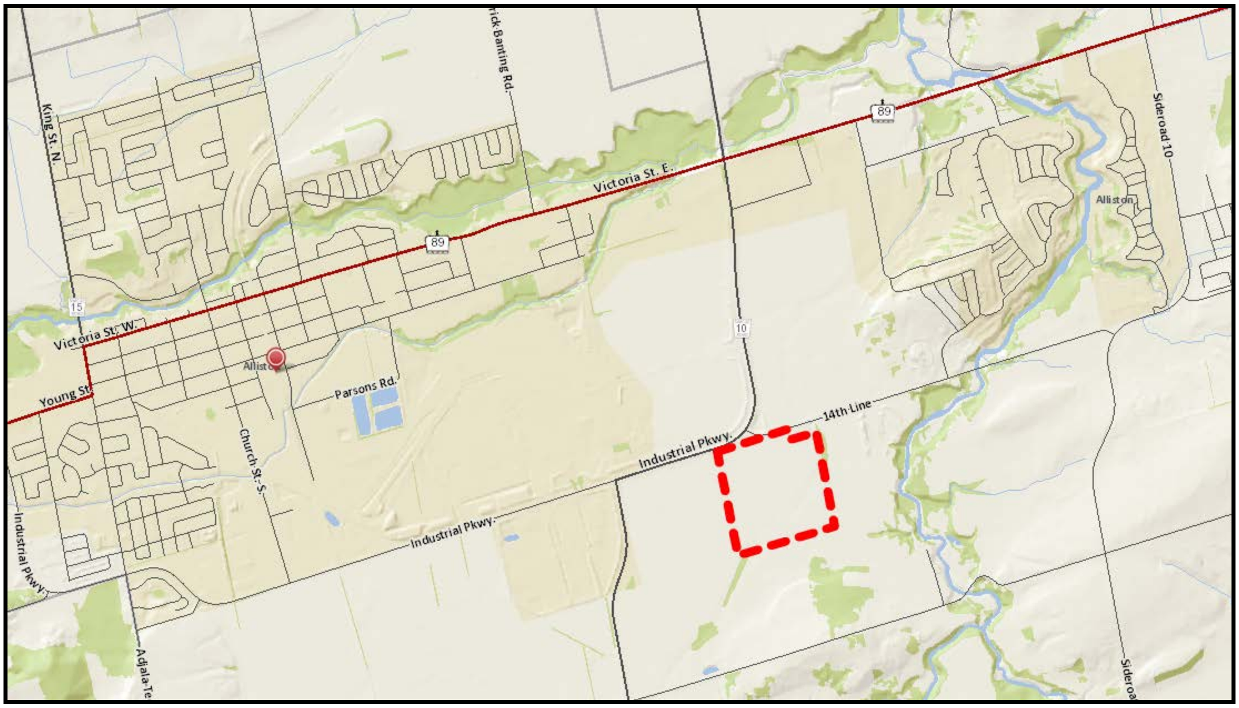
Proposed Road / Lotting Plan



Neighbourhood Map

Alliston Site #3
ADDRESS: 6485 14th Line, Alliston

Vacant land within a larger parcel of future development land proposed for industrial and service commercial. The owner is proposing the sale of the front 12.55 acres of this site. It would likely be onerous to sever these lands without consideration to the larger development parcel. An institutional user may have more opportunity to sever a parcel as compared to a private sector user. The outlined site represents the larger parcel.



Nearest	14th Line & Industrial Parkway (County Rd 10)
Municipality	Town of New Tecumseth
Asking Price	$2,500,000
Asking	$199,203 per acre
Listing	Expired Listing
Listing	Michael Saperia 416-636-8898 (The Behar Group Realty)
Owner	New Tecumseth Land Corp
PIN #	Part of 581450060

SITE INFORMATION

Lot Area (acres)	12.55 acres	**Services**	Water and Sanitary Reported Available, Hydro & Gas in area

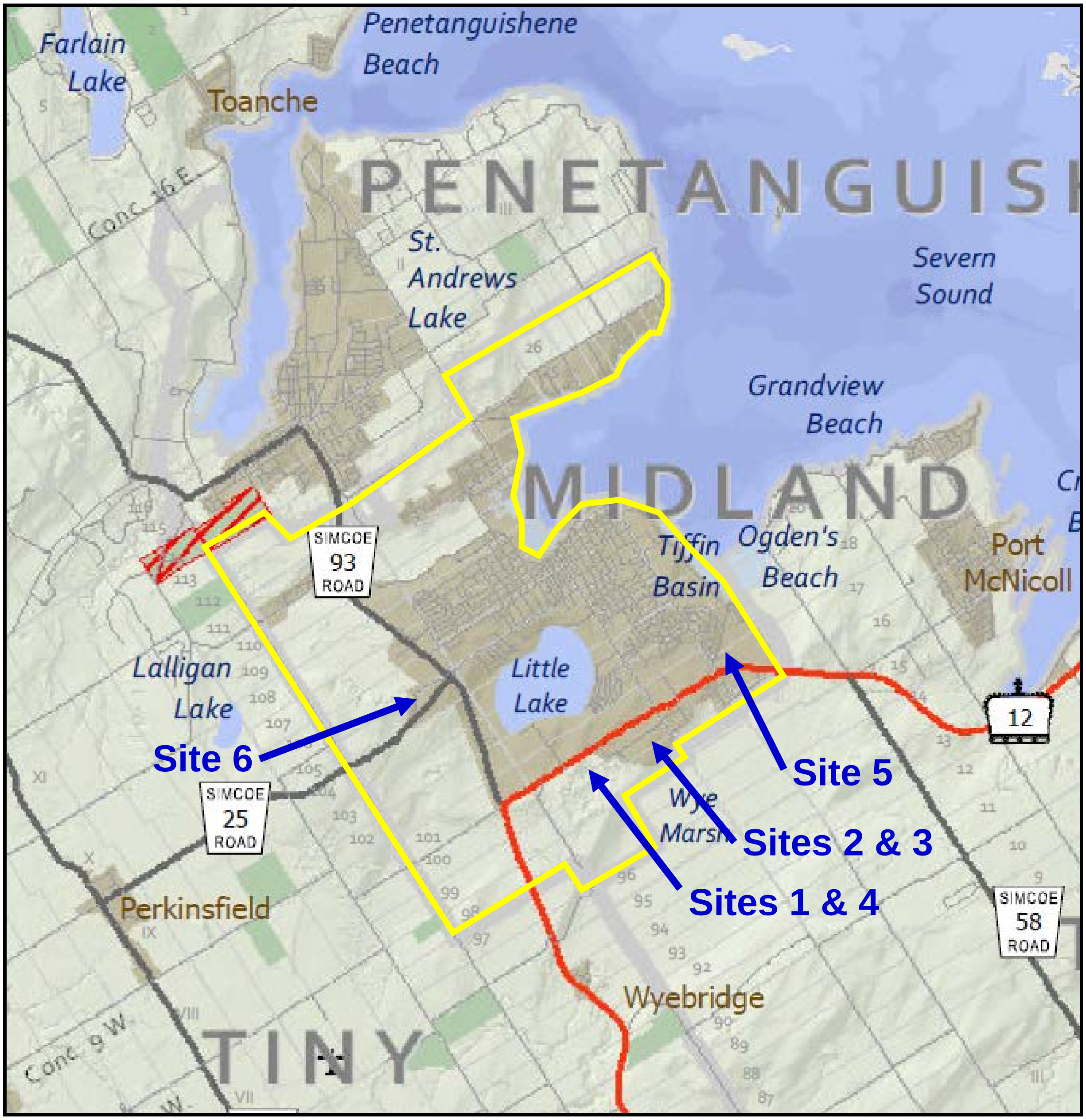
COMMENTS		
Location	This site is within the Alliston Industrial area at the southern limit of the community. These industrial lands are closely associated with the Honda Manufacturing Plant and are mostly transportation based such as trucking facilities or related manufacturing. The Honda Plant is to the northwest of the property. This property is located within the Alliston Industrial/Commercial Area Secondary Plan which is mostly new development or future development lands. Immediately surrounding this site is agricultural and future development lands to the west, south and east. The Honda Plant and future development lands are to the north.	
Land Use	Official Plan: OPA 29 – Urban General Industrial; Urban Light Industrial; Urban Service Commercial Zoning: A1 – Agricultural The Official Plan includes a mix of designations on the larger parcel. It is unclear at this time what part of the site would be potentially acquired for the BUCC site and what designation would be applicable. The site would require a zoning amendment.	
Site Description	The site is cleared and generally level agricultural land.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	Unknown
	Fiber Optic	Rogers available to the site or nearby
	Hydro Supply	44 kV along Industrial Parkway
	Distance to Rail Line	1.5 km to Rail Line
	Distance to Major Highway	Remote
	Greenfield / Infill	Greenfield
	Brownfield	No
	Improved	No
	Severable	Needs to be severed from larger parcel
	Natural Buffer	No

ADDITIONAL MAPS AND PHOTOS

Site Photo

Neighbourhood Map

TOWN OF MIDLAND



General Overview

The Town of Midland is a medium sized community with a population of 16,572 (Census 2011). Growth within the community has been somewhat stagnant with little increase in population over the past 15 years. The majority of growth in the community is the emerging retirement population which is replacing in part the population once supporting an industrial force. Midlands industrial sector once included a number of large scale manufacturers however downsizing and closings in recent years has seen a severe decline in this employment base. The good quality Georgian Bay harbour and associated amenity remains a main attraction for the area.

Infrastructure:

The Town of Midland is a serviced community. The core residential and commercial areas are fully serviced. Industrial areas at the west and south limit of the community include a mix of fully serviced, partially serviced and unserviced lands. Fully serviced industrial lands are generally located in the Heritage Business Park and Whitfield industrial area at the southeast limit of the community.

Rogers reportedly provides access to fibre optic networks through a large majority of the community. Hydro is provided by Midland Power Utility Corporation.

Transportation

The Town of Midland is accessed by Highway 93 from the south and Highway 12 from the east. Both highways connect to Highway 400. Additional secondary roads can be used such as County Road 26 and County Road 6, which provide access to Barrie. Rail access is no longer available to the community.

The primary access route between Barrie and Midland is Highway 93 and Highway 400. The most direct alternative route would be County Road 26 and County Road 6.

Hydro Control Centre to Community Limits

Primary Route	50 km +/- (35min)
Secondary Route	50 km +/- (45mn)

Development Activity / Charges

The Town of Midland has experienced slow growth with limited new development in recent years.

Development Charges (2015)

Non-Residential DC	$6.48 per sq.ft.

Tax Rates (Effective 2014)

Industrial (New Construction)	3.106888 %
Excess Industrial Land	2.240477 %

Land Use

The most likely Official Plan designations that would allow for the BUCC use are "Employment Areas". The zoning by-law does outline data processing centre as a use which is likely similar to the proposed BUCC. Industrial zones of M1-Industrial are best suited to the proposed BUCC use. Additional zones such as M2-Industrial and HC-Highway Commercial may also permit the use but could require an amendment.

Recommended Site Summary Table

Town	Midland					
Site # / Ranking	**M1**	**M2**	**M3**	**M4**	**M5**	**M6**
Location	16928 Hwy 12	Highway 12 & Prospect Rd	1070 King Street	Highway 12 & Brebeuf Rd	16403 Highway 12	1337 Sundowner Road
Site Characteristics						
Size	14.85	13.17	21.31	24.63	7 acres +/- (Potential up to 15 acres)	7.64
Interior / Corner	Corner	Interior	Interior	Corner	Interior	Corner
Road Access Routes	Multiple	Multiple	1	Multiple	Multiple	Multiple
Road Frontage #	2	2	1	2	1	2
Sanitary Services	Yes	Yes	Yes	Needs Extending	Yes	Partial
Water Services	Yes	Yes	Yes	Needs Extending	Yes	Partial - Needs Extending
Fiber Optic	Nearby	Nearby	Nearby	Nearby	Nearby	Nearby
Hydro Supply	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Greenfield / Infill	Infill	Infill	Infill	Infill	Infill	Infill
Brownfield	No	No	No	No	Unknown	No
Improved	No	No	Yes	No	No	Yes (House)
Natural Buffer	No	No	Partial	Partial (Forest)	No	Potentially (Forested)
Site Land Use (Zoning)	M1-H - Industrial	M1 - Industrial	M1-H - Industrial	M1-H - Industrial	M2 - Industrial	HC-H - Highway Commercial
Surrounding Use Type*	Ind, Future Dev, Sand Pit	Ind, Com	Ind, EP, Rural	Ind, Rural, Sand Pit	Ind	Ind, Rural
Distance to Rail Line	Remote	Remote	Remote	Remote	Remote	Remote
Distance to Major Highway	Remote	Remote	Remote	Remote	Remote	Remote
Availability						
MLS / Private / Government	MLS - Expired Listing	Not currently offered but expected to be listed	Not actively offered	MLS - Expired Listing	MLS - Active Listing	MLS - Expired Listing
Asking Price	$1,575,000	Estimated in the range of $100,000 to $125,000/ acre	Estimated under $100,000 per acre	$800,000 $32,481 per acre	$499,000	$899,000
Contact	Cindy McQuirter-Farley (Previous Listing Agent - Remax)	Nick Dupuis (Remax)	Michael Kenney (Owner)	Cheryl Ferguson (Previous Listing Agent - Century 21)	Brian Jacques & Joan Therrien (Royal LePage)	Grant Evans (Royal Lepage)
Contact #	705-526-9366	705-790-3573	No Contact #	877-424-2121	705-526-9770	705-526-4271

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Midland Site #1
ADDRESS: 16928 Highway 12, Midland

Nearest	Highway 12 & Beamish Rd
Municipality	Town of Midland
Asking Price	$1,575,000
Asking	$106,060 per acre
Listing	Expired Listing
Listing	Cindy Mcquirter-Fairley 705-526-9366 (Previous Listing Agent – Remax)
Owner	Coland Developments Corporation
PIN #	585130363

SITE INFORMATION

Lot Area (acres)	14.85 acres	**Services**	Water and Sanitary Nearby, Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the southern limit of the Town of Midland. The lands along Highway 12 are developed with a mix of industrial and commercial. Industrial development is typically established on the south side of Highway 12, within small industrial parks while some big box commercial is present on the north side of Highway 12.

Immediately surrounding this site is a pit to the south, OPP building to the east, Town of Midland public works property to the west and future development land to the north.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Employment Area
Zoning: M1-H - Industrial

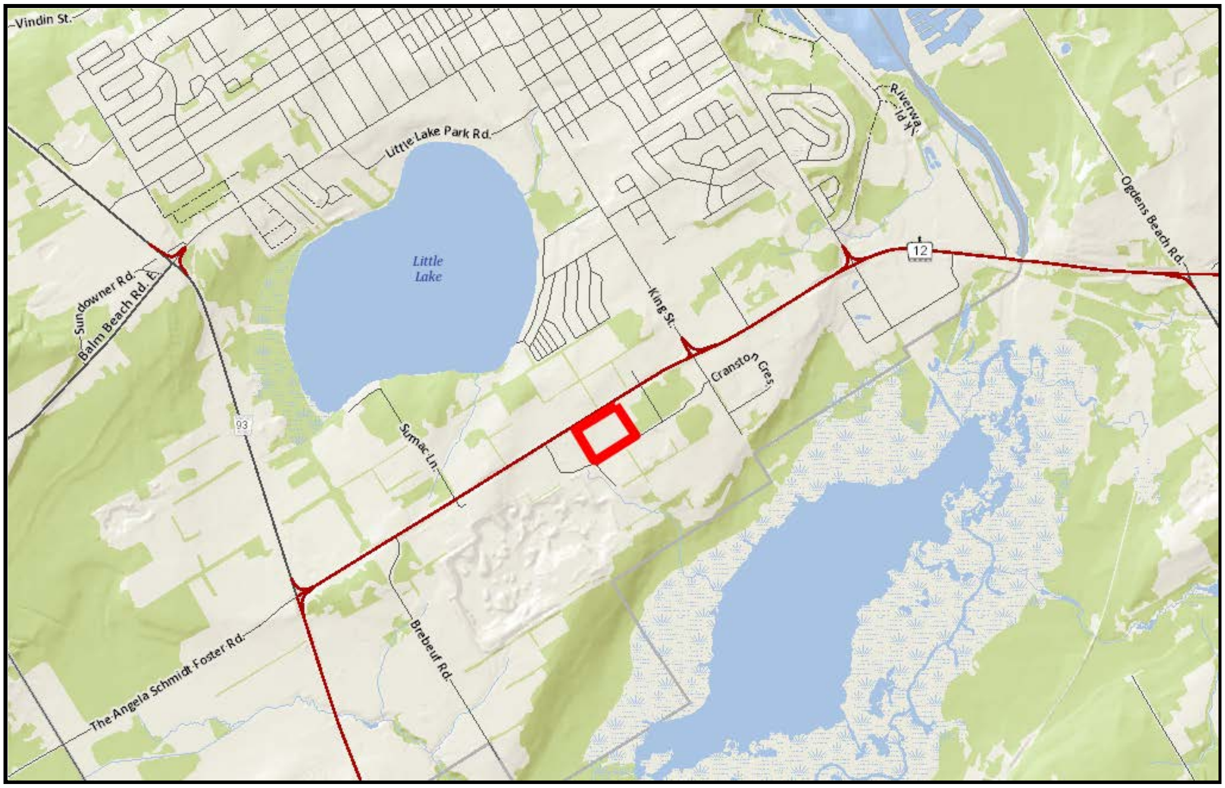
The Employment Area designation provides for a range of industrial, commercial and institutional uses. The zoning allows for a range of uses and would allow for the proposed BUCC facility. The zoning allows for open storage but it must be concealed from sight from all adjacent streets.</td></tr>
<tr><td>Site Description</td><td colspan="2">The western portion of the property slopes downward from west to east. The eastern portion of the site is slightly rolling. The site has a mix of overgrown grassland and scrub forest. Some more mature trees are present at some of the property limits.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner</td></tr>
<tr><td>Road Frontages</td><td>2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to or nearby</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Likely</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

Midland Site #2
ADDRESS: Highway 12 & Prospect Rd, Midland



Nearest Intersection	Highway 12 & Jones Rd
Municipality	Town of Midland
Asking Price	Not Available
Asking $/Acre	Estimated to be in the range $100,000 to $125,000 per acre
Listing Status	Anticipated to be listed soon.
Listing Contact	Nick Dupuis 705-790-3573 (Remax)
Owner	1315012 Ontario Inc.
PIN #	585130126, 585130127 & 585130223

SITE INFORMATION

Lot Area (acres)	13.17 acres	**Services Available**	Water and Sanitary; Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the southern limit of the Town of Midland. The lands along Highway 12 are developed with a mix of industrial and commercial. Industrial development is typically established on the south side of Highway 12, within small industrial parks while some big box commercial is present on the north side of Highway 12.

Immediately surrounding this site is a small motel to the west, a future commercial area to the east, a retail plaza to the north and industrial and institutional uses to the south.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Employment Area
Zoning: M1 - Industrial

The Employment Area designation provides for a range of industrial, commercial and institutional uses. The zoning allows for a range of uses and would allow for the proposed BUCC facility. The zoning allows for open storage but it must be concealed from sight from all adjacent streets.</td></tr>
<tr><td>Site Description</td><td colspan="2">This property is level and cleared. The site has frontage along Highway 12 along the northern property limit and Prospect Blvd along the southern property limit.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to or nearby</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Yes</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

ADDITIONAL PHOTOS AND MAPS

Site Photo

Neighbourhood Map

Midland Site #3
ADDRESS: 1070 King St, Midland

Large parcel of land located at the rear of an existing business park with services at the road. This property is not actively listed but the Town of Midland has indicated that the owner may be willing to sell if a buyer was present. To gain access from multiple directions additional lands or an agreement may be needed over adjoining sites, one being a vacant parcel owned by the Town of Midland.

Nearest	King Street & Prospect Blvd
Municipality	Town of Midland
Asking Price	Not Available
Asking $/Acre	Estimated under $100,000 / acre
Listing Status	Not actively marketed
Listing Contact	Michael Kenney (Owner)
Owner	Michael Kenney
PIN #	5851030376

SITE INFORMATION

Lot Area (acres)	21.31 acres	**Services**	Water and Sanitary, Hydro, Gas in area

COMMENTS		
Location	This site is located near the southern limit of the Town of Midland. The lands along Highway 12 are developed with a mix of industrial and commercial. Industrial development is typically established on the south side of Highway 12, within small industrial parks while some big box commercial is present on the north side of Highway 12. Immediately surrounding is a small Georgian Collage campus to the north, vacant employment lands to the west, rural and environmentally protected lands to the south and industrial properties to the east.	
Land Use	Official Plan: Employment Area Zoning: M1-H - Industrial The Employment Area designation provides for a range of industrial, commercial and institutional uses. The zoning allows for a range of uses and would allow for the proposed BUCC facility. The zoning allows for open storage but it must be concealed from sight from all adjacent streets.	
Site Description	This property slopes gradually downward from north to south. The property is mostly cleared.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	1
	Fiber Optic	Rogers available to or nearby
	Hydro Supply	Unknown
	Distance to Rail Line	Remote
	Distance to Major Highway	Remote
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	Yes (Small House)
	Severable	Potentially
	Natural Buffer	Partial

ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

Midland Site #4
ADDRESS: Highway 12 & Brebeuf Rd, Midland

Nearest Intersection	Highway 12 & Brebeuf Rd
Municipality	Town of Midland
Asking Price	$800,000
Asking $/Acre	$32,481 per acre
Listing Status	Expired Listing
Listing Contact	Cheryl Ferguson 877-424-2121 (Previous Listing Agent – Century 21)
Owner	Sherk Farms Ltd
PIN #	585130121

SITE INFORMATION

Lot Area (acres)	24.63 acres	**Services Available**	Water and sanitary are not to the property and would need extending from the east.

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the southern limit of the Town of Midland. The lands along Highway 12 are developed with a mix of industrial and commercial. Industrial development is typically established on the south side of Highway 12, within small industrial parks while some big box commercial is present on the north side of Highway 12.

Immediately surrounding this site is a pit to the south, rural uses to the west, Town of Midland public works property to the east and future development land to the north.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Employment Area
Zoning: M1-H - Industrial

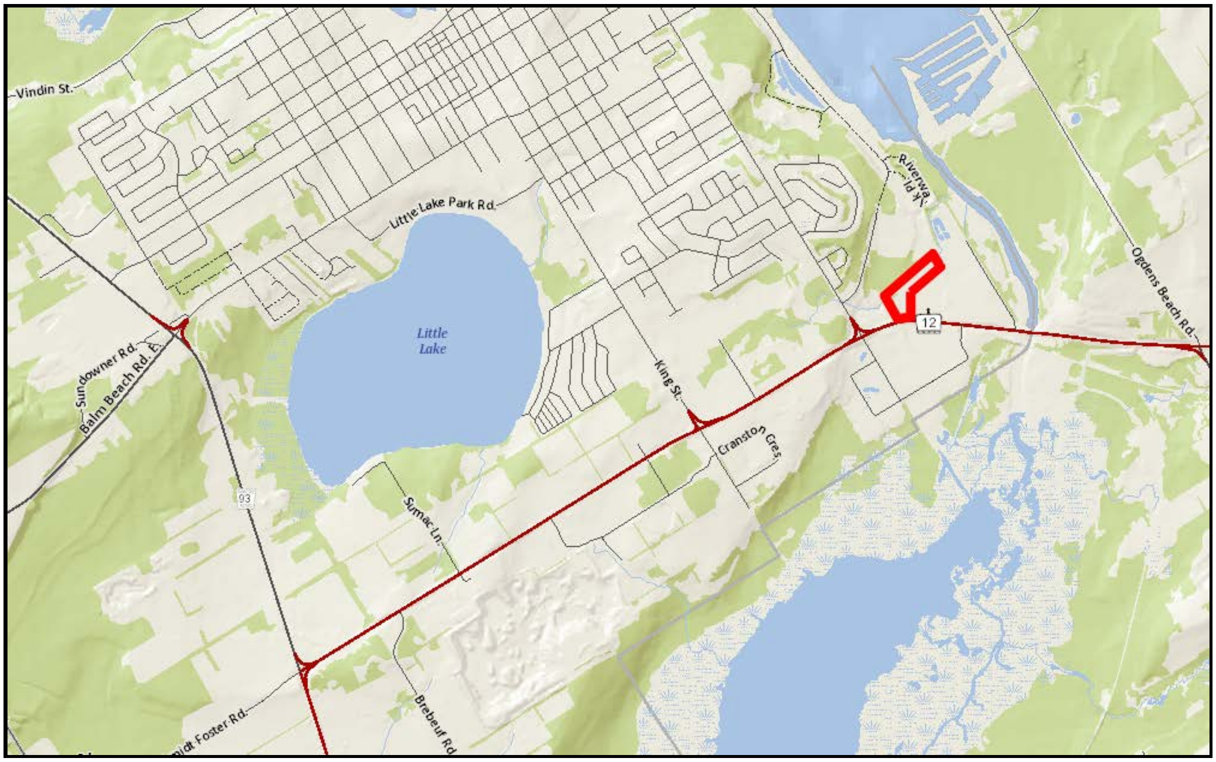
The Employment Area designation provides for a range of industrial and commercial uses. The zoning allows for a range of uses and would allow for the proposed BUCC facility. The zoning allows for open storage but it must be concealed from sight from all adjacent streets.</td></tr>
<tr><td>Site Description</td><td colspan="2">The eastern portion of the site is rolling and mostly cleared land while the western portion of the property slopes upward. The western portion of the site and the southern property limit is treed.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner</td></tr>
<tr><td>Road Frontages</td><td>2</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to or nearby</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Potentially</td></tr>
<tr><td>Natural Buffer</td><td>Potentially (Forest)</td></tr>
</table>

ADDITIONAL MAPS AND PHOTOS

Site Photo

Neighbourhood Map

Midland Site #5
ADDRESS: 16403 Highway 12, Midland



Nearest Intersection	Highway 12 & William St
Municipality	Town of Midland
Asking Price	$499,900
Asking $/Acre	$71,414 per acre
Listing Status	Active Listing
Listing Contact	Brian Jacques & Joan Therrien 705-526-9770 (Royal LePage)
Owner	Baytech Plastics Inc
PIN #	Part of 58475-0362

SITE INFORMATION

Lot Area (acres)	7 acres +/- (Potential for up to 15)	**Services Available**	Water and Sanitary, Hydro, Gas in area

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">This site is located near the southern limit of the Town of Midland. The lands along Highway 12 are developed with a mix of industrial and commercial. Industrial development is typically established on the south side of Highway 12, within small industrial parks while some big box commercial is present on the north side of Highway 12.

This site is located on the north side of Highway #12 and is currently part of a larger property improved with a large manufacturing building.

Immediately surrounding this site are forested future development lands to the north and west and large industrial facilities to the east and south.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Employment Area
Zoning: M2 - Industrial

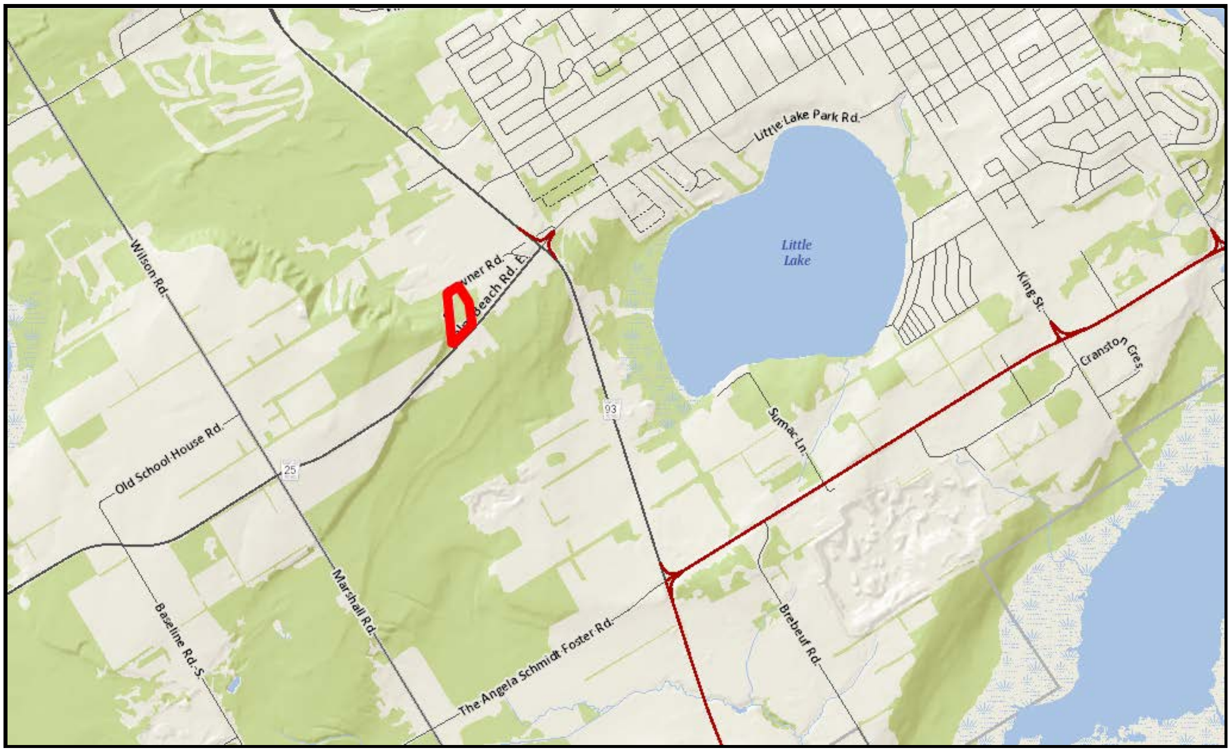
The Employment Area designation provides for a range of industrial, commercial and institutional uses. The zoning allows for industrial uses including heavy industrial uses. The zoning allows for open storage. The proposed BUCC facility may be permitted in this designation.</td></tr>
<tr><td>Site Description</td><td colspan="2">The site is generally level with some mixed scrub brush and overgrown grassland. The site is slightly below road grade.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>1</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available to or nearby</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>Unknown</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Needs to be severed.</td></tr>
<tr><td>Natural Buffer</td><td>No</td></tr>
</table>

ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

Midland Site #6
ADDRESS: 1337 Sundowner Rd, Midland



Nearest Intersection	County Rd 24 & Sundowner Rd
Municipality	Town of Midland
Asking Price	$899,000
Asking $/Acre	$117,670 per acre
Listing Status	Expired Listing
Listing Contact	Grant Evans Royal Lepage 705-526-4271
Owner	Coland Developments Corporation
PIN #	584040074 & 584040075

SITE INFORMATION

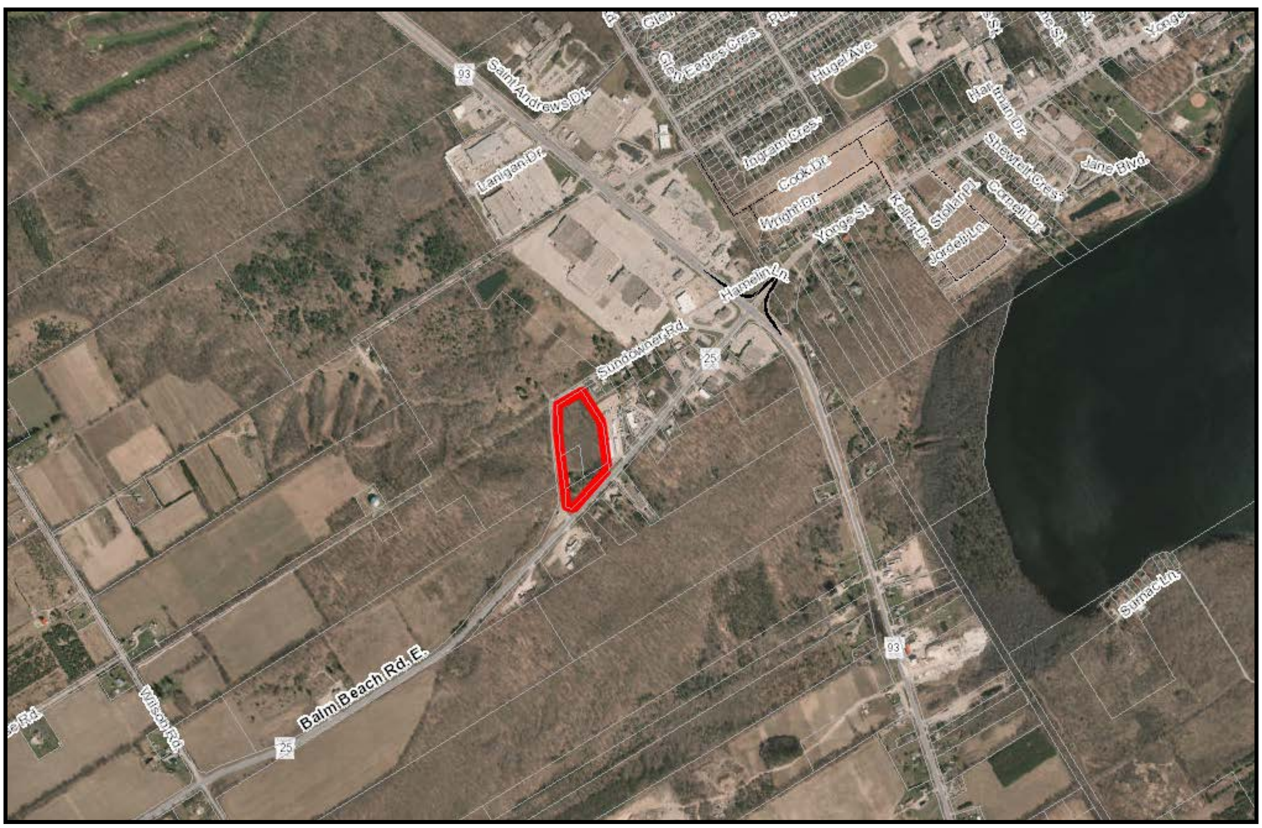
Lot Area (acres)	7.64 acres	**Services Available**	Water at frontage / Sanitary needs extending / Hydro, Gas in area

COMMENTS		
Location	This site is located at the western limit of the Town of Midland. This neighbourhood is primarily light industrial with commercial uses located slightly to the east along County Rd 93. Immediately surrounding this site are forested rural lands to the west and light industrial to the east. A small self storage facility is located on the adjoining property to the east.	
Land Use	Official Plan: Employment Area Zoning: HC-H – Highway Commercial The Employment Area designation provides for a range of industrial, commercial and institutional uses. The zoning allows for a range of service commercial uses including a public use that may provide for the proposed BUCC facility.	
Site Description	This site is thickly forested and slopes gradually downward from south to north. The property is currently improved with an older residence.	
Other Criteria	Interior / Corner	Corner
	Road Frontages	2
	Access Routes	Multiple
	Fiber Optic	Rogers available to or nearby
	Hydro Supply	Unknown
	Distance to Rail Line	Remote
	Distance to Major Highway	Remote
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	Yes (House)
	Severable	No
	Natural Buffer	Yes (Forested)

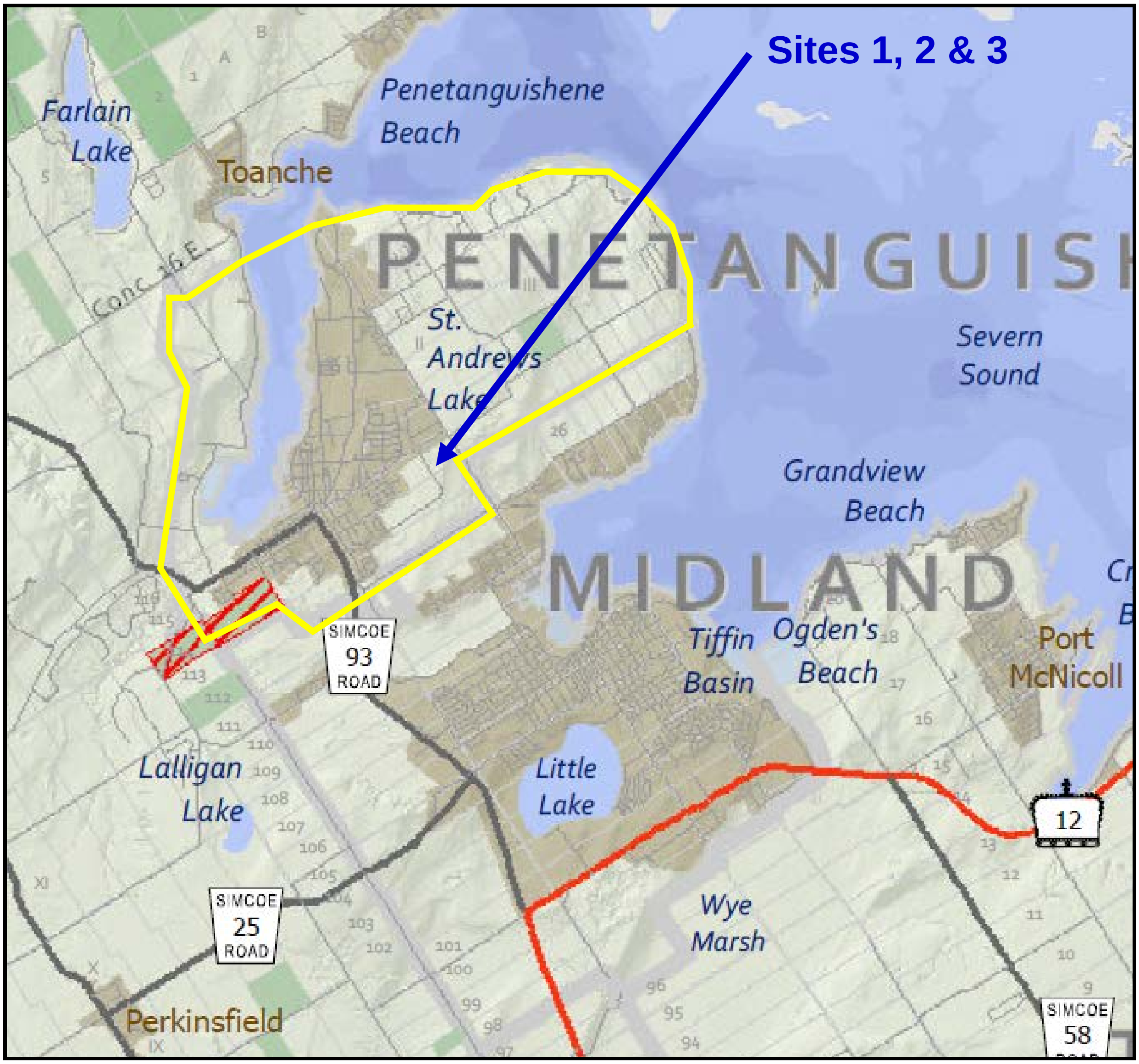
ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map



TOWN OF PENETANGUISHENE



General Overview

Penetanguishene is a small community located near the northern limit of the County of Simcoe. The Bay provides an excellent quality harbour, which combined with the large cottage population of the region, produces a strong tourism industry. Growth in the community, particularly full time residents, has been limited as is evident in the population decline experienced between the 2006 and 2011 Census periods, the 2011 census was 9,111. The Town has a small industrial base comprised primarily of a few larger manufacturers however, manufacturing decline has occurred with plants closing or downsizing. The closing or downsizing of larger manufacturing plants has had a negative effect on local employment. Large institutional facilities such as the Central North Correctional Centre and Georgian Manor Senior's Complex provide a large portion of the local employment.

Infrastructure:

This is a fully serviced community with municipal services including water and wastewater available in a majority of the Town. Serviced employment / industrial lands are available at the eastern limit of the property. A small pocket of land north of Robert Street East is mostly developed with industrial uses however the south side is mostly vacant employment lands. It is our understanding that infrastructure supplying this area generally runs along Robert Street East.

Rogers reportedly provides access to fibre optic networks through a large majority of the community and is reportedly nearby the employment lands at the east side of the Town. Hydro is provided by Powerstream.

Transportation

Access to the Town of Penetanguishene is provided by Highway 93 which runs north-south from Highway 400. Secondary access can be achieved from County Road 27 / County Road 6 which also run north south from the City of Barrie.

The primary access route between the Barrie and Penetanguishene is Highway 400 to Highway 93.

Hydro Control Centre to Community Limits

Primary Route	55 km +/- (40 min)
Secondary Route	55 km +/- (45 min)

Development Activity / Charges

Development has been limited in the community with minimal growth in recent years. A new residential subdivision has been developing gradually in the southwest portion of the Town. Some new institutional development has occurred including Georgian Village and Manor, a large County of Simcoe run seniors' complex, and the construction of Waypoint Centre for Mental Health Care on the existing Mental Health Centre Penetanguishene site located northeast of Penetanguishene.

Development Charges (Feb 1, 2015)

Non Residential	$11.12 per sq.ft.
Eligible Industrial (Town Exempt)	$3.38 per sq.ft. (If proposed use qualifies)

Tax Rates (Effective 2013)

Industrial (New Construction)	3.467900 %
Excess Industrial Land	2.254135 %

Land Use

The Industrial Official Plan designation would best support the proposed BUCC use. The majority of the available employment development lands are designated Deferred Developments and would require a rezoning which would be obtainable.

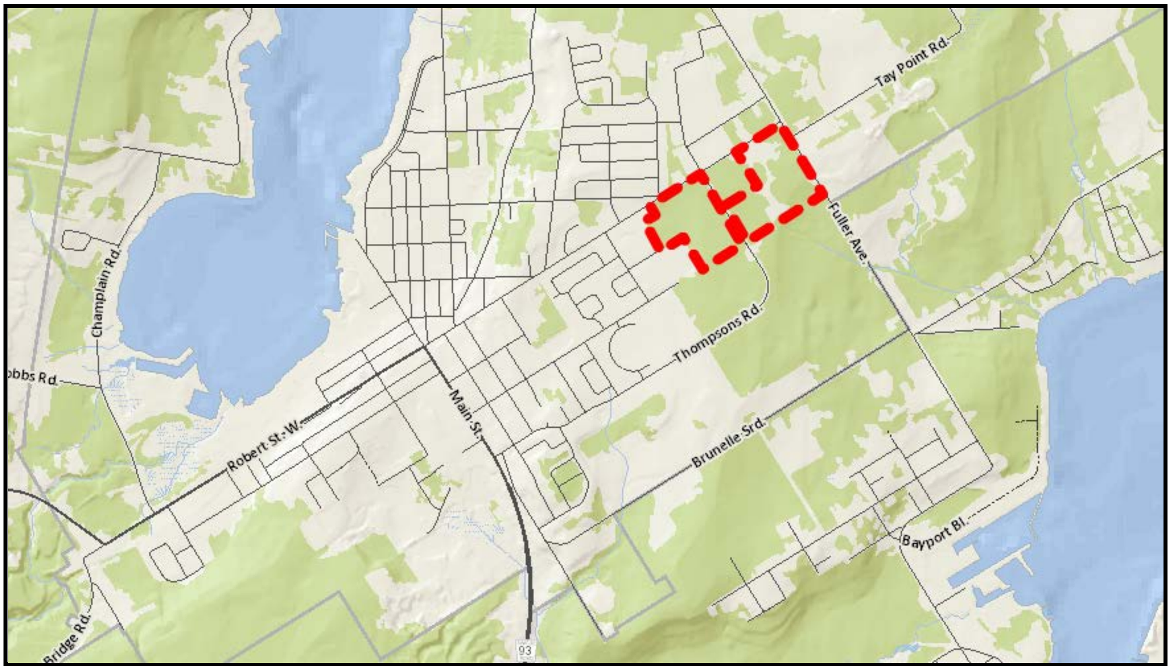
Recommended Site Summary Table:

Town	Penetanguishene		
Site # / Ranking	P1	P2	P3
Location	Thompson Road & Robert Street	163 Robert Street E	51 Dunlop Street
Site Characteristics			
Size		7 acres +/-	13.33
Interior / Corner	Corner & Interior	Interior	Corner
Road Access Routes	Multiple	Multiple	Multiple
Road Frontage #	2 to 3	1	3
Sanitary Services	Yes	Yes	Yes
Water Services	Yes	Yes	Yes
Fiber Optic	Nearby	Nearby	Nearby
Hydro Supply	44 kV & 4.16 kV	44 kV & 4.16 kV	Unknown
Greenfield / Infill	Infill	Infill	Infill
Brownfield	No	No	No
Improved	No	No	Yes
Natural Buffer	Yes (Forested)	Yes (Forested)	Partial
Site Land Use (Zoning)	D - Defered Development	M4-1-H - Industrial	G - Institutional
Surrounding Use Type*	Ind, I, Res	Ind	Res, Ind land
Distance to Rail Line	Remote	Remote	Remote
Distance to Major Highway	Remote	Remote	Remote
Availability			
MLS / Private / Government	Not actively listed but potentially available	MLS - Active (Larger Parcel)	School expected to be deemed surplus
Asking Price	Estimated in the range of $75,000 to $100,000 / acre	Estimated in the range of $75,000 to $100,000 / acre	Unknown
Contact	Potential Contact Karen Harris Family Member	Gord Cook (Colliers)	Andrew Keuken Simcoe County Disttrict School Board
Contact #	705-526-7509	416-777-2200	705 734 6363 ext. 11513

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Penetanguishene Site #1
ADDRESS: Thompson Road & Robert Street, Penetanguishene

Opportunity exists within the Town of Penetanguishene which has a number of larger sites within the Industrial Park having services along the property frontage. Potential sites include two large parcels of vacant forested land at the intersection of Robert St and Thompson Rd. These sites are owned by the Mcleod Family and could likely be severed to provide for site options.



Nearest Intersection	Thompson Road & Robert Street
Municipality	Town of Penetanguishene
Asking Price	Unknown
Asking $/Acre	Estimated to be in the range of $75,000 to $100,000 per acre.
Listing Status	Not actively listed but potentially available
Listing Contact	Karen Harris 705-526-7509 Family Member
Owner	Mcleod
PIN #	Part or 584410443 Part or 584410262

SITE INFORMATION

Lot Area (acres)	Various	**Services Available**	Water and Sanitary along Robert Street, Gas in area

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">These lands are located near the eastern limit of Penetanguishene. The area north of Robert Street is a small industrial park that is primarily improved with a few large manufacturing facilities and some additional small to midsized users. The lands to the south of Robert Street, near the intersection of Thompson Road and Fuller Ave are vacant industrial lands that are thickly forested. To the west are established neighbourhoods.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial
Zoning: D – Deferred Development

The Official Plan designation provides for a wide range of uses and would support the proposed BUCC use. A zoning amendment would be required but would likely be supported.</td></tr>
<tr><td>Site Description</td><td colspan="2">These lands are thickly forested and generally level.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner and Interior</td></tr>
<tr><td>Road Frontages</td><td>2 to 3</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers fibre available or nearby</td></tr>
<tr><td>Hydro Supply</td><td>44kV & 4.16 kV</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Needs to be severed from larger parcel.</td></tr>
<tr><td>Natural Buffer</td><td>Thickly Forested</td></tr>
</table>

ADDITIONAL MAPS & PHOTOS

Site Photo

Neighbourhood Map

Penetanguishene Site #2
ADDRESS: 163 Robert Street   Surplus Land, Penetanguishene

A large manufacturing property is currently listed. This listing includes the building which is roughly 150,000 sq.ft. located on the north side of Robert Street and a vacant parcel of land (9.87 acres) on the south side of Robert Street. The vacant parcel is improved with a parking lot that is likely needed in support of the manufacturing plant. The parking is situated along the Robert Street frontage. The remaining 7 acres +/- south of the parking lot is vacant forested land. Opportunity may exist to acquire the surplus land absent the larger manufacturing plant.

Nearest Intersection	Thompson Road & Robert Street
Municipality	Town of Penetanguishene
Asking Price	Unknown
Asking $/Acre	Estimated to be in the range of $75,000 to $100,000 per acre.
Listing Status	Larger property is actively listed.
Listing Contact	Gord Cook (Colliers) 416-777-2200
Owner	CCL Industries Inc.
PIN #	Part of 584410421

SITE INFORMATION

Lot Area (acres)	7 acres +/-	**Services Available**	Water and Sanitary along Robert Street, Gas in area

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">These lands are located near the eastern limit of Penetanguishene within an industrial area of the community.

Immediately surrounding this site is a large industrial plant to the north and vacant future development lands to the east, west and south.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Industrial
Zoning: M4-1-H - Industrial

The Official Plan designation provides for a wide range of uses and would support the proposed BUCC use. The zoning allows for a public use but relatively limited industrial uses. A rezoning may be needed.</td></tr>
<tr><td>Site Description</td><td colspan="2">The surplus lands are generally level and thickly forested.</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Interior</td></tr>
<tr><td>Road Frontages</td><td>1</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available or nearby.</td></tr>
<tr><td>Hydro Supply</td><td>44kV & 4.16 kV</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>No</td></tr>
<tr><td>Severable</td><td>Site would need to be severed.</td></tr>
<tr><td>Natural Buffer</td><td>Yes (Forested)</td></tr>
</table>

Penetanguishene Site #3
ADDRESS: 51 Dunlop Street, Penetanguishene

This site is the former Penetanguishene Secondary School that is proposed to be closed and deemed surplus. The school will be reportedly closed in 2016. The property is improved with a 93,253 sq.ft. school building.

Nearest Intersection	Thompson Road & Robert Street
Municipality	Town of Penetanguishene
Asking Price	Unknown
Asking $/Acre	n/a
Listing Status	Not actively listed but potentially available
Listing Contact	Simcoe County School Board – Andrew Keuken 705 734 6363 ext. 11513
Owner	Simcoe County District School Board
PIN #	584410259

SITE INFORMATION

Lot Area (acres)	13.33 acres	**Services Available**	Water and Sanitary, Hydro, Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">These lands are located near the eastern limit of Penetanguishene

Immediately surrounding this site is an established residential neighbourhood to the west, public school to the north and future development lands to the east and south.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Residential Area
Zoning: G - Institutional

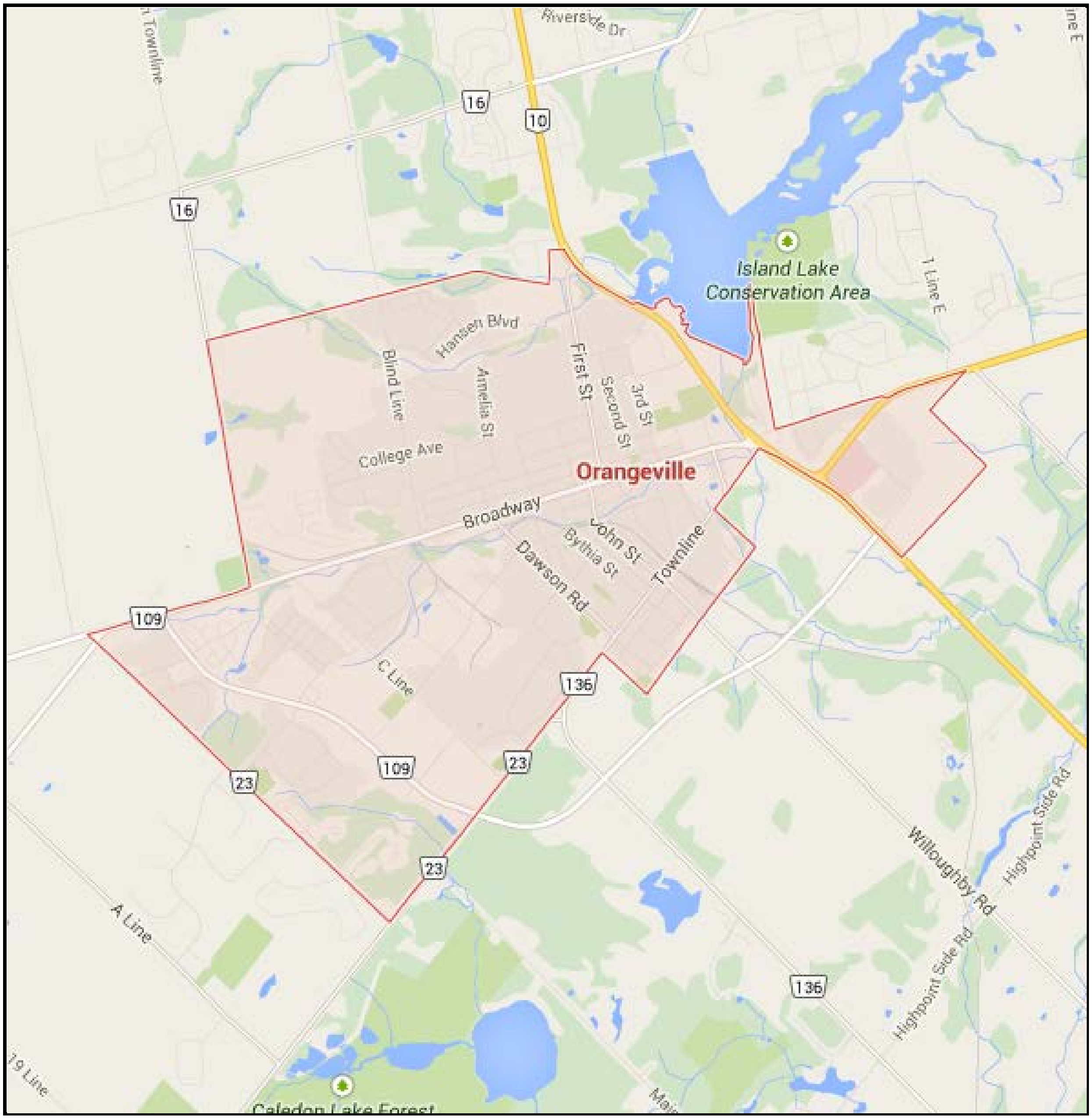
The proposed BUCC may be considered a public use which would be permitted within the Institutional zoning designation. The Residential Official Plan designation does not appear to provide for the proposed use. An OPA and rezoning may be necessary.</td></tr>
<tr><td>Site Description</td><td colspan="2">The subject site is generally cleared, level and above the grade of the road frontage. The rear of the site is forested. The large school building has an area of 93,253 sq.ft..</td></tr>
<tr><td rowspan="12">Other Criteria</td><td>Interior / Corner</td><td>Corner</td></tr>
<tr><td>Road Frontages</td><td>3</td></tr>
<tr><td>Access Routes</td><td>Multiple</td></tr>
<tr><td>Fiber Optic</td><td>Rogers available or nearby.</td></tr>
<tr><td>Hydro Supply</td><td>Unknown</td></tr>
<tr><td>Distance to Rail Line</td><td>Remote</td></tr>
<tr><td>Distance to Major Highway</td><td>Remote</td></tr>
<tr><td>Greenfield / Infill</td><td>Infill</td></tr>
<tr><td>Brownfield</td><td>No</td></tr>
<tr><td>Improved</td><td>Yes</td></tr>
<tr><td>Severable</td><td>Potentially</td></tr>
<tr><td>Natural Buffer</td><td>Forested to the Rear</td></tr>
</table>

ADDITIONAL PHOTOS

Site Photo

Site Photo

TOWN OF ORANGEVILLE



General Overview

The Town of Orangeville is a mid-sized community with a population of approximately 27,975. The community has experienced modest growth with an increase in population of 3.6% between 2006 and 2011. The Town has a relatively large business park area that is comprised of a mix of light industrial and manufacturing operations. Orangeville also acts as a centre for commercial and service activity for the surrounding area.

Close proximity to the GTA is advantageous with easy access to large urban centres while maintaining the amenity and attraction of a smaller community.

Infrastructure:

The majority of the community is fully serviced. The Towns largest business park, at the southwest corner of the community, is fully serviced. A section of industrial / service commercial lands along Highway 9 at the east limit of the Town is not serviced with municipal sewer.

Rogers reportedly provides access to fibre optic networks through a large majority of the community. Hydro is provided by Orangeville Hydro.

Transportation

Orangeville is primarily accessed from Highway 10 (Hurontario St) from the south and Highway 9 from the east. Highway 10 runs north-south and connects to Brampton while Highway 9 runs east-west connecting to Highway 400.

The primary access route between the Barrie and Orangeville is Highway 400 to Highway 9. A number of alternative routes are provided by various county and local roads running through the adjoining rural areas.

Hydro Control Centre to Community Limits

Primary Route	80 km +/- (60 min)
Secondary Route	80 km +/- (65 min)

Development Activity / Charges

Development Charges (September 2014)

Industrial DC	$8.68 per sq.ft. (May be eligible for exception)
Institutional DC	$8.68 per sq.ft.

Tax Rates (Effective 2014)

Industrial (New Construction)	4.206402 %
Vacant Industrial Land	2.944481 %

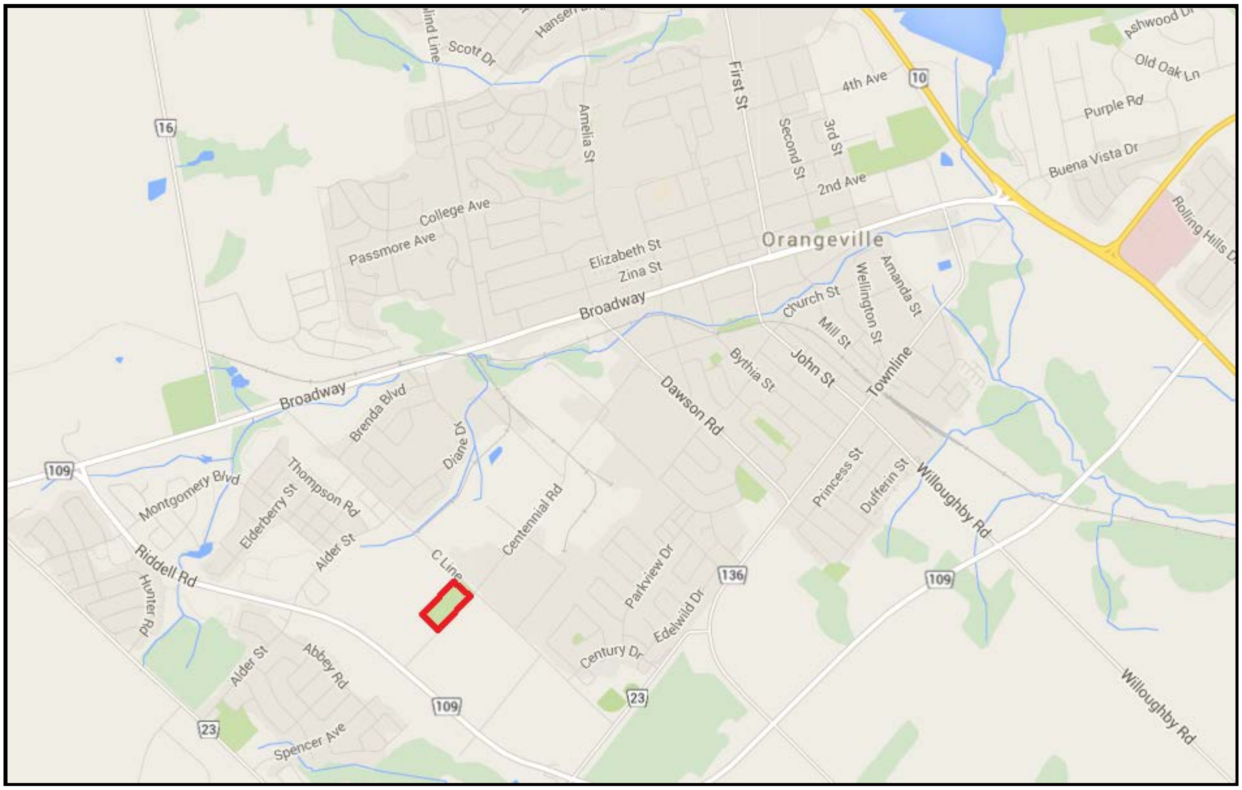
Land Use

We have identified only one suitable site within Orangeville. This site is designated Employment Area in the Official Plan and zoned General Industrial. The applicable lands use appears to support the proposed BUCC use.

Recommended Site Summary Table:

Town	Orangeville
Site # / Ranking	**OV1**
Location	NW Corner of Centennial Road & C Line
Site Characteristics	
Size	5.16
Interior / Corner	Corner
Road Access Routes	Multiple
Road Frontage #	2
Sanitary Services	Yes
Water Services	Yes
Fiber Optic	Nearby
Hydro Supply	Unknown
Greenfield / Infill	Infill
Brownfield	No
Improved	No
Natural Buffer	No
Site Land Use (Zoning)	M1 - General Industrial
Surrounding Use Type*	Ind
Distance to Rail Line	Remote
Distance to Major Highway	Remote
Availability	
MLS / Private / Government	Active Listing - Municipal
Asking Price	$215,000 per acre
Contact	Orangeville EDO - Ruth Phillips
Contact #	519-941-0440 ext 2291
*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial SC - Service Commercial EP - Environmental; Ru - Rural	

Orangeville Site #1
ADDRESS: Centennial Rd & C Line, Orangeville



Nearest Intersection	Centennial Rd & C Line
Municipality	Town of Orangeville
Asking Price	$1,109,400
Asking $/Acre	$215,000 per acre
Listing Status	Active
Listing Contact	Orangeville EDO Ruth Phillips 519-941-0440 ext 2291
Owner	Town of Orangeville
PIN #	Not Available Part 2 & 3 Plan 7R6001 Part 2 Plan 7R6176

SITE INFORMATION

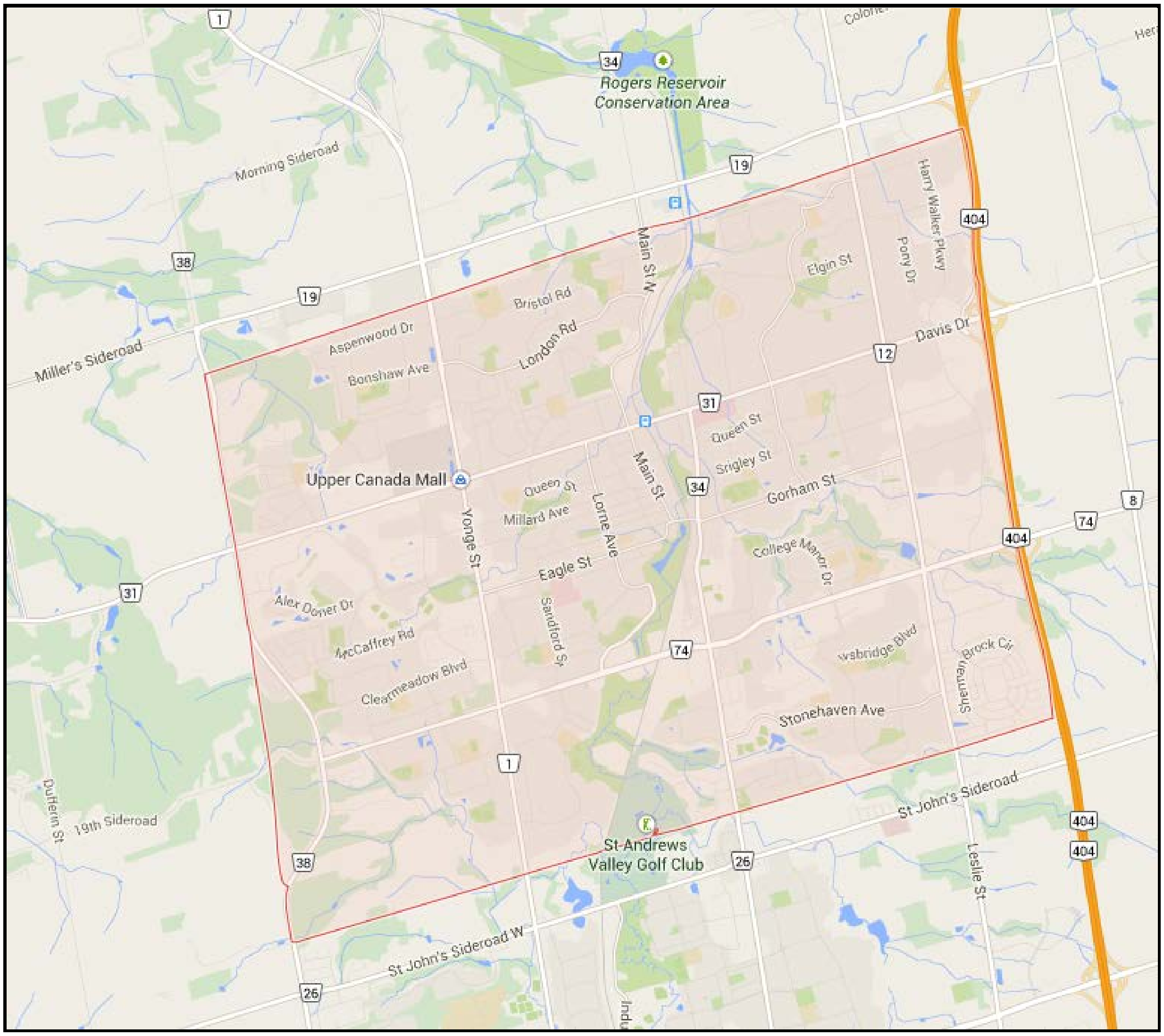
Lot Area (acres)	5.16 acres	**Services Available**	Water and Sanitary, Hydro, Gas

COMMENTS		
Location	Industrial site located in the western portion of the Town of Orangeville. This property is situated within an established industrial park that is mostly developed out. To the north of the property is a large manufacturing plant. Slightly to the west is a retail / commercial plaza. To the south is a garden centre while to the east are light industrial buildings.	
Land Use	Official Plan: Employment Area Zoning: M1 – General Industrial The Official Plan designation provides for a wider range of employment based uses. This designation prohibits any use that is considered a public nuisance or danger to health or danger of fire or explosion. Open storage is permitted but must have adequate buffering. The zoning allows for a range of uses but prohibits most heavy manufacturing or obnoxious uses. The land use would likely allow for the proposed BUCC facility.	
Site Description	The site is cleared and level.	
Other Criteria	Interior / Corner	Corner
	Road Frontages	2
	Access Routes	Multiple
	Fiber Optic	Rogers available to or nearby.
	Hydro Supply	Unknown
	Distance to Rail Line	Remote
	Distance to Major Highway	Remote
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	Yes
	Natural Buffer	No

ADDITIONAL MAPS AND PHOTOS

Neighbourhood Map

TOWN OF NEWMARKET



General Overview

The Town of Newmarket is located near the northern limit of York Region. This community has experienced strong growth in recent years. Demand has been present for both residential development lands and employment based development land. Pockets of land at the northwest and southeast are actively developing with residential while employment based development / industrial has occurred along the eastern limit. The Town has a relatively limited supply of vacant development land with the majority of the business park fully developed and limited residential land remaining. Some intensification and redevelopment is proposed along the Yonge Street corridor.

Infrastructure:

The Town of Newmarket is a fully serviced community. Water and wastewater servicing within Newmarket is under the control of York Region. Due to this servicing arrangement, development has extended into East Gwillimbury to the north while remaining integrated into development within Newmarket.

Hydro is provided by Newmarket Hydro.

Transportation

Access to the Town of Newmarket is provided by Highway 404, which runs north-south along the western limit of the community. Highway 400 also provides north-south access but is located slightly west of the community limits. Highway 9 provides east-west access to Newmarket from Highway 400. Commuter GO-rail service is present.

The primary access route between the Barrie and Newmarket is Highway 400 and Highway 9 which leads to the west limit of the community. To access the eastern side and the area of employment lands, Bathurst Street and Green Lane are utilized to bypass the busy core areas.

Hydro Control Centre to Community Limits

Primary Route	50 km +/- (30min)
Secondary Route	55 km +/- (45mn)

Development Activity / Charges

The Town of Newmarket has been actively developing with substantial residential and employment based development. Vacant developments are generally limited in the community.

Development Charges (Sept 2014)

Non-Residential DC	$25.20 per sq.ft.

Tax Rates (Effective 2014)

Industrial	2.285536 %
Vacant Industrial Land	1.485598 %

Land Use

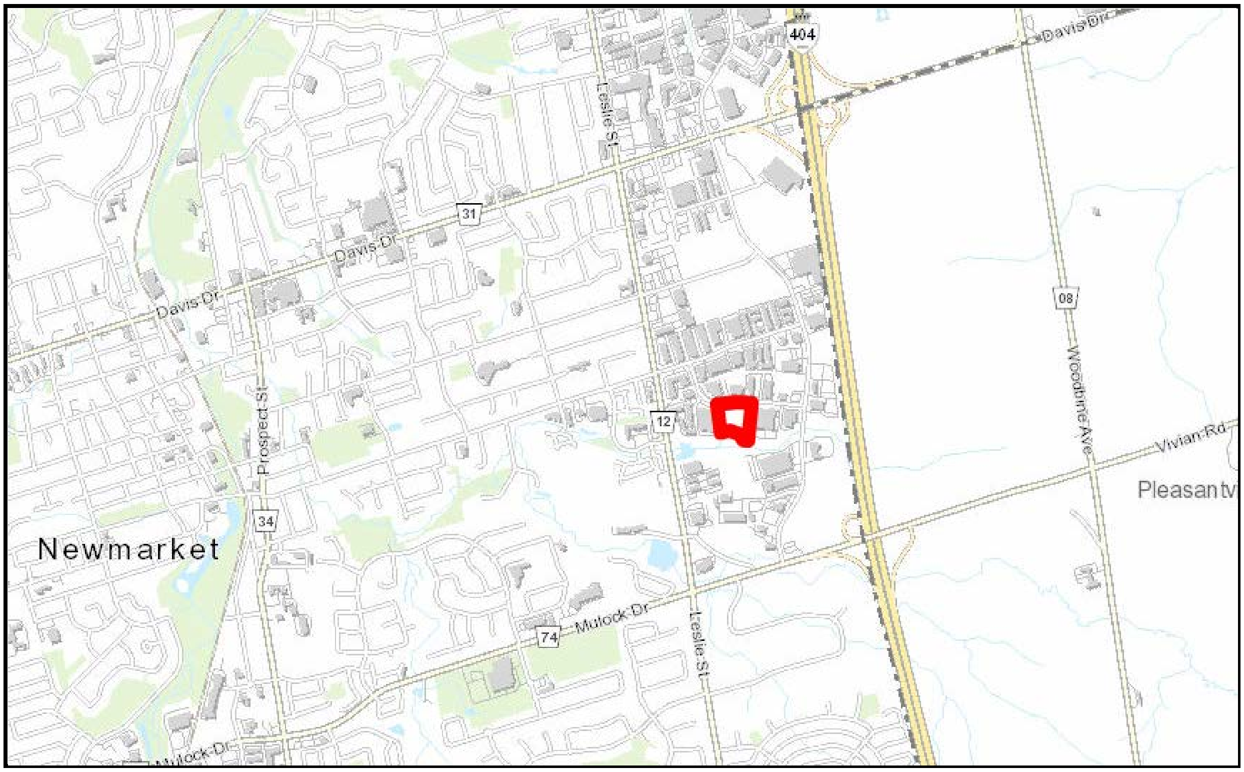
The most likely Official Plan designations best suited for the BUCC use are "Mixed Employment" however "General Employment" would also be suitable. The zoning by-law employment designations do not outline a use that would clearly encompass the BUCC. It is likely that most employment designations would support the use.

Recommended Site Summary Table:

Town	Newmarket	
Site # / Ranking	**N1**	**N2**
Location	1166-1186 Nicholson Rd	Harry Walker Parkway & Stackhouse Road
Site Characteristics		
Size	5.67	11 to 21 acres
Interior / Corner	Interior	Corner
Road Access Routes	Multiple	Multiple
Road Frontage #	1	2
Sanitary Services	Yes	Yes
Water Services	Yes	Yes
Fiber Optic	Unknown	Unknown
Hydro Supply	Unknown	Unknown
Greenfield / Infill	Infill	Infill
Brownfield	No	No
Improved	No	No
Natural Buffer	Yes	No
Site Land Use (Zoning)	EG - Employment General	EH - Employment Heavy
Surrounding Use Type*	Ind	Ind, Sc
Distance to Rail Line	Remote	Remote
Distance to Major Highway	450m to Hwy 404	300m to Hwy 404
Availability		
MLS / Private / Government	Privately Offered	Not Actively Offered
Asking Price	Estimated in the range of $700,000 to $1,000,000 / acre	Estimated in the range of $700,000 to $1,000,000 / acre
Contact	Ryan Hood (Avison Young)	Birock Investments Inc
Contact #	416-833-4681	905-895-0371

*Land Use: BP - Buisness Park; I - Institutional; Res - Residential; Ind - Industrial
SC - Service Commercial; EP - Environmental; Ru - Rural

Newmarket Site #1
ADDRESS: 1166 1186 Nicholson Road, Newmarket



Nearest Intersection	Nicholson Rd & Harry Walker Parkway
Municipality	Town of Newmarket
Asking Price	n/a
Asking $/Acre	Lands within this area have recently traded in the range of $700,000 to $1,000,000 per acre. Given the interior location we would expect a value at the lower limit of this range for this property. We are not aware of owners expectations.
Listing Status	Reported available for sale but not actively listed
Listing Contact	Ryan Hood Avison Young 416-833-4681
Owner	HOOPP Realty Inc
PIN #	036190207

SITE INFORMATION

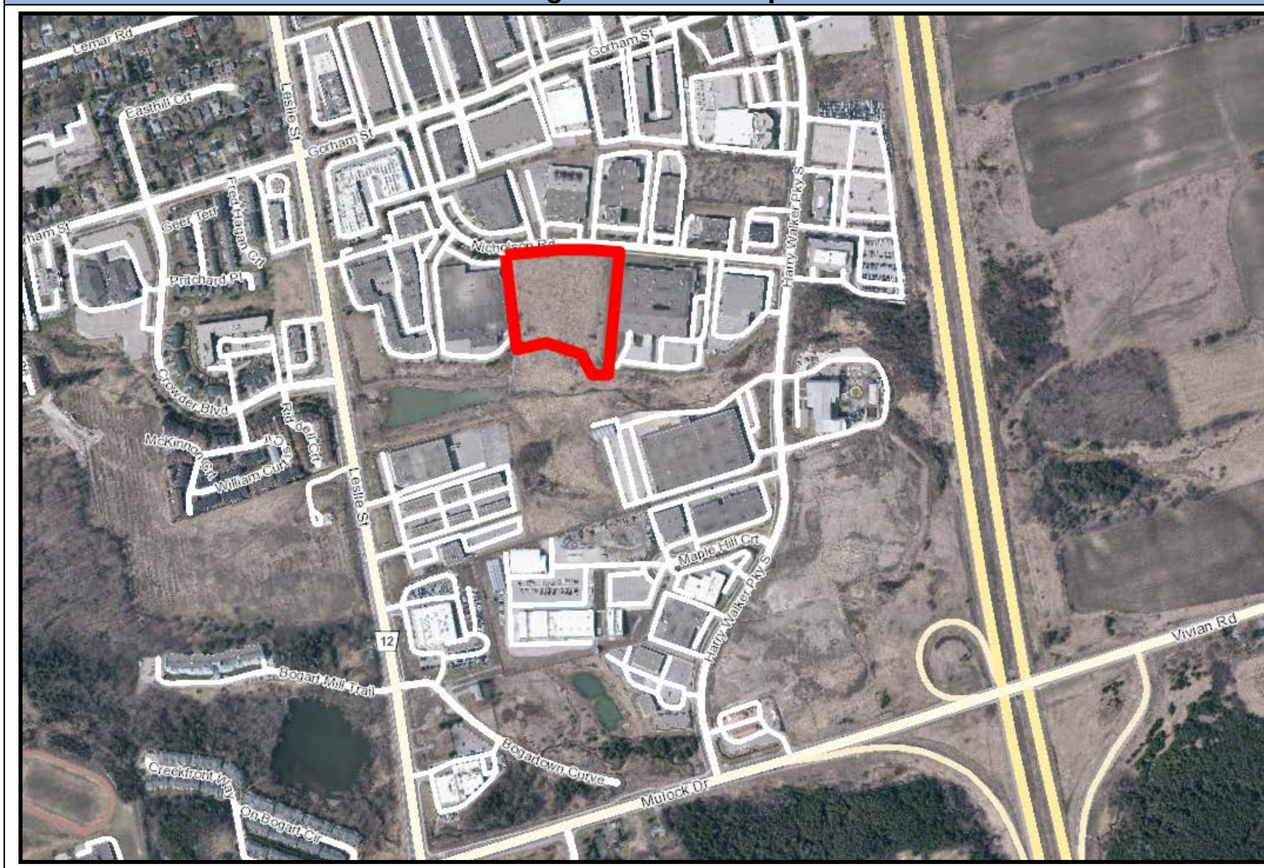
Lot Area (acres)	5.67 acres	**Services Available**	Water and Sanitary, Hydro, Gas

COMMENTS		
Location	Industrial site located within a fully developed portion of the Newmarket Business Park. This site is fronts on a secondary street connecting to Harry Walker Parkway and Gorham Street. This portion of the business park is comprised of light industrial business park type uses.	
Land Use	Official Plan: Mixed Employment Zoning: EG – General Employment The Official Plan designation provides for uses such as professional office, research and development, data processing centres, manufacturing wholly within a building and service commercial. This designation does not allow for outside storage. The zoning designation does not specifically outline the proposed BUCC use but would likely be suitable. The Official Plan designation would support the proposed BUCC facility.	
Site Description	The site is cleared and generally level with a slight slope downward from north to south. The rear of the property borders a drainage course area that provides a slight natural buffer.	
Other Criteria	Interior / Corner	Interior
	Road Frontages	1
	Access Routes	Multiple
	Fiber Optic	Unknown
	Hydro Supply	Unknown
	Distance to Rail Line	Remote
	Distance to Major Highway	450 m to Hwy 404
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	No
	Natural Buffer	Yes

ADDITIONAL MAPS AND PHOTOS

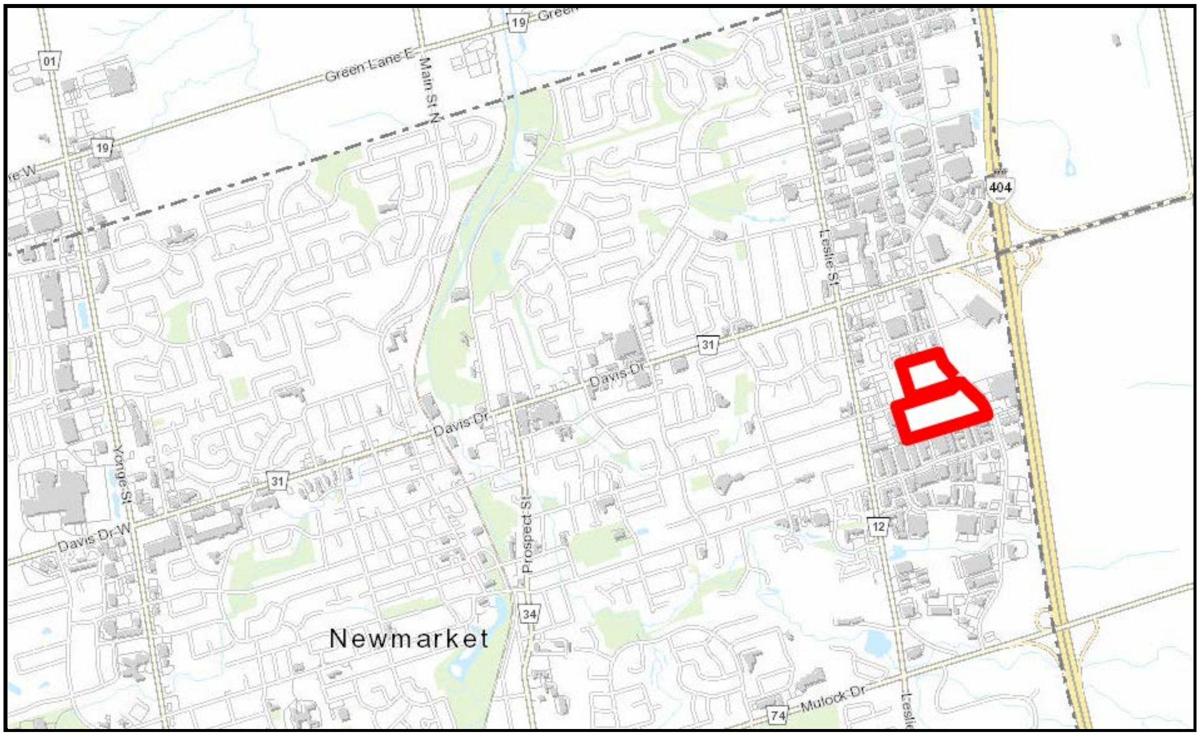
Site Photo (Google Street View)

Neighbourhood Map



Newmarket Site #2
ADDRESS: Harry Walker Pkwy & Stackhouse Rd, Newmarket

These sites are large parcels of serviced employment land in Newmarket's business park. The sites do not appear to be actively offered for sale. We have attempted to contact the owner, Birock Investments Inc, but have not been successful. Many land owners within Newmarket offer build-to suit leasing opportunity only which may be the case in this instance. An opportunity may exist for a site in this area but additional investigation will be necessary.



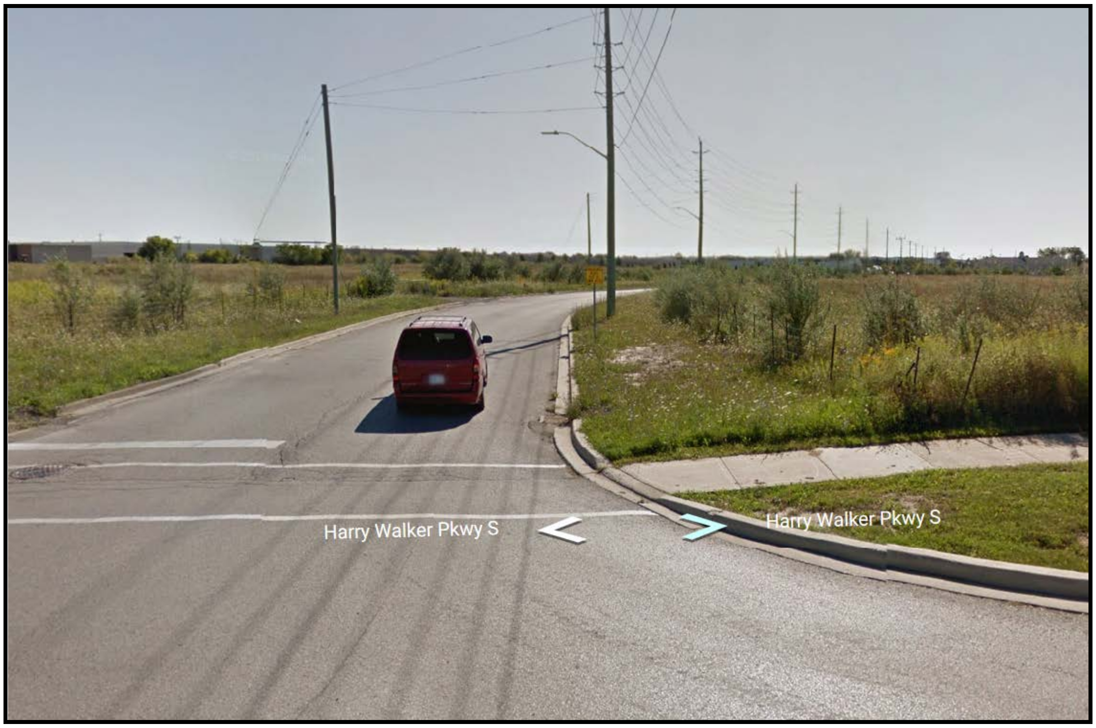
Nearest Intersection	Harry Walker Pkwy & Stackhouse Rd
Municipality	Town of Newmarket
Asking Price	n/a
Asking $/Acre	Lands within this area have recently traded in the range of $700,000 to $1,000,000 per acre. We are not aware of owners expectations.
Listing Status	Not actively listed
Listing Contact	Birock Investments Inc. 905-895-0371
Owner	Birock Investments Inc.
PIN #	036190232 & 036190233

SITE INFORMATION

Lot Area (acres)	11 to 21 acres	**Services Available**	Water and Sanitary, Hydro, Gas

COMMENTS		
Location	Industrial site located within a fully developed portion of the Newmarket Business Park. These sites front on Harry Walker Parkway, a busy road, and Stackhouse Street a secondary road. This portion of the business park is comprised of light industrial and service commercial uses.	
Land Use	Official Plan: General Employment Zoning: EH – Heavy Employment The Official Plan designation provides for uses such as manufacturing and warehousing. Outside storage is permitted in this area. The zoning designation does not specifically outline the proposed BUCC use but would likely be suitable. The zoning allows for accessory outside storage. The land use would likely support the proposed BUCC facility but also allows for some heavy industrial uses.	
Site Description	The site is cleared and generally level.	
Other Criteria	Interior / Corner	Corner
	Road Frontages	2
	Access Routes	Multiple
	Fiber Optic	Unknown
	Hydro Supply	Unknown
	Distance to Rail Line	Remote
	Distance to Major Highway	300 m to Hwy 404
	Greenfield / Infill	Infill
	Brownfield	No
	Improved	No
	Severable	Likely
	Natural Buffer	No

ADDITIONAL MAPS AND PHOTOS
Site Photo (Google Street View)



Neighbourhood Map

School Energy Coalition Interrogatory # 62

Issue:

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

Reference:

B1-01-01 Section 3.8 GP-29

With respect to the Customer Service Billing Investments:

Interrogatory:

a) Please provide a cost breakdown of the proposed $15M investment.

b) [p.1] The evidence states "[a]s a result, Hydro One is introducing a redesigned bill in 2017. Additional capital funding will be required in 2022 to introduce further enhancements to ensure customers remain satisfied and understand their bill". Please explain what additional enhancements Hydro One plans to make to its bill in 2022 and why they were not made in 2017.

c) Please provide any research summaries or reports Hydro One undertook for its 2017 bill redesign.

Response:

a) Please refer to Exhibit I-2-Staff-9 part H.

b) Please refer to Exhibit I-2-Staff-9 part H.

c) Please refer to Exhibit I-2-Staff-8 and Exhibit I-2-Staff-9 part A.

School Energy Coalition Interrogatory # 63

Issue:

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

Reference:

DSP-Appendix_A

Interrogatory:

Please expand Tables 8-10 to include planned spending in the 2021 and 2022 test year in each of the Acquired Utilities' (Haldimand County Hydro, Norfolk Power Distribution, and Woodstock Hydro Services) service territories.

Response:

Forecast costs for years 2021 and 2022 have been added to Tables 8-10 as reproduced below for each of the each of the Acquired Utilities.

		Historical ($M, actual) (previous actual)			Forecast ($M)					
Segment	**OEB Category**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Haldimand Capital	System Access				0.9	0.9	0.9	0.9	0.9	0.9
	System Renewal				1.7	1.7	2.3	2.4	2.4	2.4
	System Service				0.8	0.8	0.7	0.7	0.7	0.7
	Total	6.3	6.9	4.6	3.4	3.4	3.9	4.0	4.0	4.0
Haldimand OM&A		7.5	7.7	6.0	5.0	5.1	5.1	5.2	5.3	5.4
Norfolk Capital	System Access				0.6	0.6	0.6	0.6	0.7	0.7
	System Renewal				1.8	1.3	1.3	1.3	2.3	2.3
	System Service				0.2	0.2	0.2	0.2	0.2	0.2
	Total	3.5	2.1	0.9	2.6	2.1	2.1	2.1	3.2	3.2
Norfolk OM&A		7.2	5.9	2.7	3.1	3.1	3.2	3.2	3.2	3.3
Woodstock Capital	System Access				0.5	0.5	0.5	0.5	0.6	0.7
	System Renewal				1.4	1.5	1.0	1.2	1.2	1.2
	System Service				0.3	0.3	0.3	0.3	0.4	0.4
	Total	3.4	2.2	3.1	2.2	2.3	1.8	2.1	2.2	2.3
Woodstock OM&A		4.1	4.2	3.8	2.1	2.1	2.3	2.1	2.2	2.2
Grand Total Capital	System Access				2.1	2.1	2.1	2.1	2.1	2.3
	System Renewal				4.9	4.5	4.6	4.9	5.9	6.0
	System Service				1.2	1.2	1.1	1.2	1.3	1.3
	Total	13.2	11.1	8.6	8.2	7.8	7.8	8.1	9.4	9.5
Grand Total OM&A		**18.8**	**17.8**	**12.5**	**10.2**	**10.3**	**10.6**	**10.5**	**10.7**	**10.8**

School Energy Coalition Interrogatory # 64

Issue:

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

Reference:

DSP-Appendix_A

Interrogatory:

For each of the Acquired Utilities (Haldimand County Hydro, Norfolk Power Distribution, and Woodstock Hydro Services), please expand Tables 8-10, to show planned spending in each historic year (as set out in previous filed DSPs) and actuals. Please explain any variance +/- 5%.

Response:

All three of the acquired utilities were managed and operated in their status quo businesses in 2014 and 2015, therefore they did not budget nor report costs in the same manner as shown in Tables 8- 11. For 2016, the data Hydro One has available is as follows:

2016 OM&A Actuals ($M)	Norfolk	Haldimand	Woodstock
CUSTOMER CARE SERVICES	0.66	1.17	0.76
VEGETATION MANAGEMENT	0.50	0.02	0.00
LINE MAINTENANCE AND REPAIR	0.98	2.60	1.38
DISTRIBUTING & REGULATING STATION	0.06	0.43	0.21
TELECOM MONITORING AND CONTROL	0.20	0.00	0.00
LAND ASSESSMENT & REMEDIATION	0.04	0.07	0.02
BAD DEBT/OTHER MISC CHARGES	0.29	1.67	1.45
TOTAL	**2.72**	**5.96**	**3.82**

The below table summarizes the historic capital and OM&A expenditure by year in total, and by acquired LDC.

For Haldimand, 2016 capital spending was higher than anticipated due to increased customer connection and trouble calls, 2016 OM&A spending was higher than anticipated due to expenditures tracked in the miscellaneous charges category.

For Norfolk, 2015 and 2016 capital was underspent due to reductions in line betterment programs, in 2015 OM&A was higher than anticipated due to expenditures tracked in the miscellaneous charges category.

For Woodstock, 2016 OM&A was higher than anticipated due to expenditures tracked in the miscellaneous charges category.

Acquired LDCs OM&A and Capital

Distributor - Expenditure ($M)	**2014**			**2015**			**2016**		
	Planned	**Actual**	**Variance**	**Planned**	**Actual**	**Variance**	**Planned**	**Actual**	**Variance**
Haldimand - Capital	*	6.3	N/A	*	6.9	N/A	3.2	4.6	43.8%
Haldimand - OM&A	*	7.5	N/A	*	7.7	N/A	4.4	6.0	36.4%
Norfolk - Capital	**	3.5	N/A	2.9	2.1	-27.6%	2.9	0.9	-69.0%
Norfolk - OM&A	**	7.2	N/A	2.6	5.9	126.9%	2.7	2.7	0.0%
Woodstock - Capital	*	3.4	N/A	*	2.2	N/A	2.9	3.1	6.9%
Woodstock - OM&A	*	4.1	N/A	*	4.2	N/A	2.2	3.8	72.7%

* Haldimand County Hydro and Woodstock Hydro's systems were fully integrated with Hydro One's in the latter half of 2016. There is insufficient data available from the LDC's legacy financial/operating systems to provide a meaningful comparison of planned vs. actual spend in 2014-2015.

** Norfolk Power's systems fully integrated with Hydro One's in 2015. There is insufficient data available from the LDC's legacy financial/operating systems to provide a meaningful comparison of planned vs. actual spend in 2014.

School Energy Coalition Interrogatory # 65

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 provide a chart that shows for each material capital project undertaken between 2015 and 2017, its original forecasted cost to be incurred in 2015-2017 and its actual cost. Please provide an explanation for all variances +/- 5%

Response:

For 2017, financials are not available at this time.

For Distribution Station Refurbishments please refer to Exhibit I-26-Staff-159, part f).

For Distribution Lines Sustainment initiatives please refer to Exhibit I-24-Staff-115, part b).

For Life Cycle Optimization and Operational Efficiency Projects and Reliability Improvements please refer to Exhibit I-29-SEC-65, Attachment 1.

For System Upgrades Driven by Load Growth please refer to Exhibit I-30-Staff-175, part a)

Past Filing (2015-2019)				Current Project Identification Infromation		
Exhibit	**Project Description**	**Year (2013 filing)**	**Cost $M (2013 filing)**	**Status**	**Cost ($M)**	**Cost Variance (short)**
EB-2013-D2-2-3 Ref#D-05	44kV Extension to Coniston, Sudbury	2015	2.8	completed 2017	note 1	NA
EB-2013-D2-2-3 Ref#D-05	Belle River DS Voltage Conversion, Belle River	2015	1.1	completed 2017	note 1	NA
EB-2013-D2-2-3 Ref#D-05	Mattawa Voltage Converson, Mattawa	2015	1	completed 2017	note 1	NA
EB-2013-D2-2-3 Ref#D-06	Allanburg TS M7 Feeder Upgrades, Thorold	2015	1	Need met through anotl	NA	Need met through another project, M6 tie to offload some M7 load.
EB-2013-D2-2-3 Ref#D-06	Brant TS M21 to Wolverton DS F1 Tie Line	2019	1.2	Need met through anotl	NA	Met objective with more cost effective altenative with project cost under $1M.
Life Cycle Optimization not Identified in Plan	Bob-Lo DS Voltage Conversion	NA	NA	completed 2017	note 1	NA
Life Cycle Optimization not Identified in Plan	Edgeware TS M3 - Re-establishment	NA	NA	completed 2017	note 1	NA
Life Cycle Optimization not Identified in Plan	Port Arthur M6 Resupply of Port Arthur f2	NA	NA	completed 2015	1.7	NA
Life Cycle Optimization not Identified in Plan	Bobcaygeon Area Study Implementation	NA	NA	completed 2016	1.4	NA

note 1 — 2017 audited actuals are not available

OEB Staff Interrogatory # 163

Issue:

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

Reference:

Q-01-01-01 Page: 12
Budget Breakdown by OEB RRF

Interrogatory:

Hydro One includes a Capital Investment Table 5 on page 7. The December 8, 2017 Business Plan is also included with similar tables for OM&A and Capital.

a) Please explain the differences in the 2018 to 2022 Capital Expenditure numbers on page 12 of the Business Plan to Table 5 on page 7.

b) Please explain and quantify any differences between the annual proposed capital expenditures in each category shown in the Table 5 and Table 56 in Exhibit B1-1-1, DSP Section 3.2, Page 5 of 9.

Response:

a) Please find below a continuity of the differences in the 2018 to 2022 Capital Expenditure numbers on page 12 of the Business Plan to Table 5 on page 7 of Exhibit Q.

	2018	2019	2020	2021	2022
Business Plan (page 12)	**$ 632.0**	**$ 741.3**	**$ 706.8**	**$ 711.2**	**$ 797.1**
Acquired Utilities	$ -	$ -	$ -	$ 9.4	$ 9.5
OPEB Capital Reduction	$ (1.8)	$ (1.9)	$ (2.0)	$ (2.1)	$ (2.0)
Pension Capital Reduction (corporate)	$ (2.1)	$ (3.0)	$ (5.5)	$ (7.5)	$ (8.2)
Exhibit Q (table 5 page 7)	**$ 628.1**	**$ 736.4**	**$ 699.3**	**$ 711.0**	**$ 796.5**

Capital spend from the acquired utilities is not included in the Table on page 12, however is included later in the Business Plan within a stand-alone section on page 23. The potential OPEB capital reductions were identified on page 22 of the Business Plan, however were not quantified as the estimates were under review and were not available to be included in the analysis. The pension capital reduction relating to the costing of corporate staff was intended to be included in the Business Plan but was omitted inadvertently.

b) Table 4 in Exhibit Q identifies the revised Summary of Distribution Capital by OEB category for 2018-2022 test years. Table 5 in Exhibit Q identifies the changes from Table 56 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.2 to Exhibit Q. The entire difference between Table 56 and Exhibit Q relates to General Plant investments.

OEB Staff Interrogatory # 164

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

Reference:
B1-01-01 Section 1.1 Page: 17 – 19

Distribution System Plan Overview, Section 1.1 (5.2.1) Distribution System Plan Overview

Interrogatory:
"Plan A resulted in a 7.1% Hydro One rate increase in 2018 (average of 3.8% over the five years), and forecasted improvement of approximately 6% in SAIDI and 4% in SAIFI related to the company's most significant areas of reliability risk over the five year period."

"Plan B was produced that reduces the rate impact in 2018 by 1%, to 6.2% (average of 3.5% over the five years), and also delivers a reliability improvement (approximately 3% SAIDI, 2% SAIFI)."

"Hydro One also considered what would be required to achieve the lowest 2018 rate increase without material disruption to its operations. Presented as the "Plan C" scenario, Hydro One's conclusion was that this option as a whole was not viable due to the estimated degradation of approximately 2% in both SAIDI and SAIFI that would result from such a reduced level of sustainment capital investment and reductions in work programs and the associated increased backlog of assets in poor condition."

"Plan B – Modified option reduces the immediate impact on rates in 2018 to 5.4% while holding reliability performance constant over the planning period."

a) What are Hydro One's most significant areas of reliability risk over the five-year forecast period?

b) Please explain in detail how Hydro One calculated the different SAIDI and SAIFI results that would result from implementing each of the plans.
    i. For each material capital project please provide the quantitative calculation used to calculate the expected improvement of SAIDI and SAIFI for each proposed

alternative. If a quantitative calculation was not used please discuss the analysis used to produce a quantitative result.

ii. Please confirm if the SAIDI and SAIFI metrics results associated with each plan exclude the impact of major weather-related outages and/or Loss of Supply events.

iii. What are the key asset failure modes under Plans B & C that cause the largest negative impacts on SAIDI and SAIFI results?

iv. Do all studied capital plans assume the same level of vegetation management expenditure? If not, please provide the different vegetation management assumptions associated with each plan.

c) Please explain how Hydro One determined which projects and programs would be included in the portfolios that comprise Plan A, Plan B and Plan C.

i. Have the projects in each plan been optimized to deliver the best possible SAIDI and SAIFI results within the overall capital expenditure envelope associated with each scenario? If yes, please explain the methodology used to determine the optimization.

ii. Hydro One stated that an Asset Investment Planning tool is used to optimize investment candidates during the optimization process. Please explain how SAIDI and SAIFI improvements are taken into consideration during this process.

d) Please confirm if the reliability improvements expected for each Plan is calculated by a bottom-up method (i.e. The total reliability improvement is the summation of each expected reliability improvement for each project within the Plan)

Response:

a) Hydro One's most significant areas of reliability risk over the five year forecast period are related to vegetation management and defective equipment.

b)

i. The approach to identify forecasted SAIDI and SAIFI impacts of various scenarios is based upon the forecasted impact of different levels of asset replacement on overall fleet condition and professional judgment to account for potential mitigating factors. For example, an increased rate of replacement will increase the number of assets replaced, and reduce the number of assets in the fleet with deteriorated condition that require replacement. The net change in fleet level condition is then assumed to reflect a potential improvement or deterioration in reliability as shown in the table below for wood poles and used in Tables 52-53 in the DSP (Exhibit B1, Tab 1, Schedule 1).

	Wood Poles in need of replacement (k)	**Calculation**	**Change in Fleet Condition**	**Reliability Impact Shown (Tables 52-53)**
Current	106	-	-	-
Plan A	93	1 – (93/106)	12.3%	12%
Plan B	96	1 – (96/106)	9.4%	10%
Plan C	126	1 – (126/106)	(18.9)%	(18)%
Plan B-Modified	99	1 – (99/106)	6.6%	7%

For additional details on the accomplishment and condition assumptions for each of the scenarios, please refer to section 2.4 of the DSP “How the plan reflects investment planning and Asset Management’, “Reliability Performance Impact Estimation”, lines 15-20, page 2497 of 2930.

ii. Please refer to note “1” in Table 52 and 53.

iii. As Tables 52 and 53 of the DSP illustrate, for Plan B, both the SAIDI and SAIFI are most negatively impacted by "other line components” caused outages. With Plan C, both the SAIDI and SAIFI are most negatively impacted by "other line component” caused outages.

iv. No. The level of vegetation management expenditure for Plans A, B, and B-Modified are the same, however Plan C expenditure was assumed lower by approximately 1,000km/year. The different vegetation management assumptions associated with each plan are explained in Section 2.4 of the DSP under the “Vegetation Management” heading on page 2500. With the new vegetation management approach, Plan C would represent about 3000 km/year less.

c) Projects and programs levels included in Plan A and/or Plan B were assessed based on the risk mitigation or benefit to Business Objectives, as described in section 2.1 of the DSP. See DSP section 2.1.5.1 for more details (page 2385 of 2930). Plan C was not fully developed into specific programs and projects, as the option, as a whole, was deemed not viable due to a degradation of SAIDI and SAIFI that would result based on the Plan C funding level. See section 1.1 of the DSP (pages 17-19) and part c) of Exhibit I-35-BOMA-31.

   i. SAIDI and SAIFI are not specifically used to optimize the overall capital portfolio. However, reliability is one of the prioritization criteria [Reference DSP Section 2.1.5.1 Table 34 (page 2386 of 2930)] used in the investment optimization process for Plans A and B. The optimization process is described in section 2.1 of the DSP. Prioritization criteria are determined based on the risk consequence table that planners used to assess candidate investments. Refer to Appendix A to Exhibit I-24-Staff-89 for the risk consequence table and a description of the risk assessment process. After optimization, outcomes (including SAIDI and SAIFI) are assessed based on the proposed portfolio of programs and projects.
   ii. Please see the response to part c) i) above.

d) The reliability improvements expected for each Plan are not calculated using a bottom-up method. As described in section 2.4 of the DSP (page 2497 of 2930), the approach and results were calculated on a high level estimate basis, using simplified assumptions. The projected improvements are approximate and consider the impact of only select investments.

OEB Staff Interrogatory # 165

Issue:

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

Reference:

B1-01-01 Section 3.2 Page: 2509

(5.4.1 B) Capital Expenditure Forecast, Table 54 – Historical Bridge Year Capital Expenditure Summary

Interrogatory:

Table 54 - Historical and Bridge Year Capital Expenditure Summary

Category	Historical and Bridge (previous plan and actual)										
	2013*	2014*	2015			2016			2017 Bridge		
	Actual	Actual	Plan	Actual	Var	Plan	Actual	Var	Plan	Forecast	Var
	$M	$M	$M	$M	%	$M	$M	%	$M	$M	%
System Access	159.5	199.4	183.3	188.1	2.6	182.6	179.0	(1.9)	176.1	168.3	(4.4)
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	291.2	9.7	285.0	252.2	(11.5)
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	76.8	(25.7)	110.1	66.6	(39.5)
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	156.3	51.2	90.1	146.3	62.3
Total	637.0	647.5	648.9	678.3	4.5	654.7	703.2	7.4	661.4	633.5	(4.2)
System OM&A**	610.6	674.5	543.1	572.5	5.4	589.1	583.6	(0.9)	593.0	580.5	(2.1)

** 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.*

a) Does Hydro One measure scope of its capital plan vs. actual project achievement? If so, please provide details.

b) Please explain why System Service was significantly over forecasted three years in a row (i.e., 2015, 2016 and 2017)?

c) Please explain why General Plant was significantly under forecasted three years in a row (i.e., 2015, 2016 and 2017)?

Response:

a) Yes, please refer to Exhibit B1-1-1, DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.7.1 Actual Outcomes.

b) 2015 System Service investments were below OEB approved levels by $49 million. As stated in section 3.6.2, "The 2015 variance is due primarily to a $17 million variance attributable to a delay in the start of the Advanced Distribution System project." The variance is primarily attributable to a business decision to wait for the next version of the Distribution Management System software that would accommodate distributed energy resource management. Additionally, as stated in section 3.6.2, "$27 million in 2015 below planned spending levels were due to a reduction in spending on investments related to distribution system expansion. These investments were reprioritized to accommodate unforeseen increases in other areas of capital spending." The capital was reprioritized to System Renewal work, specifically, Distribution Station Refurbishments (SR-06), Distribution Lines Trouble Call and Storm Damage Response Program (SR-07) and Line Sustainment Initiatives (ISD-SR-12).

2016 System Service level of capital expenditure was $27 million under the OEB-approved level. As stated in section 3.6.2, "$25 million in 2016 below planned spending levels were due to a reduction in spending on investments related to distribution system expansion. These investments were reprioritized to accommodate unforeseen increases in other areas of capital spending." The capital was reprioritized to System Renewal work, specifically,), Distribution Lines Trouble Call and Storm Damage Response Program (SR-07) and Line Sustainment Initiatives (ISD-SR-12).

2017 System Service level of capital expenditure was $43 million under the OEB-approved level for the reasons specified in section 3.6.2: "The current 2017 forecast for System Service investments is $43 million below the previous approved plan primarily due to a reduction in investments for System Upgrades driven by load growth as a result of reprioritized spending into General Plant investments..."

c) An enhanced customer strategy and emerging business needs had driven additional investments not reflected in the previous distribution rate application resulting in General Plant being under forecasted in 2015, 2016 and 2017. The variance explanations are detailed in Exhibit B1-1-1, DSP Section 3.6, Pages 6, 7 and 8.

Witness: BOWNESS Brad

OEB Staff Interrogatory # 166

Issue:

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

Reference:

B1-01-01 Section 3.6 Page: 6, 7 and 8.

(5.4.1 B) Capital Expenditure Forecast, Table 55 – Historical and Bridge Year Capital Expenditure Breakdown by SDOC

Interrogatory:

Category	SDOC	SDOC Breakdown	Historical and Bridge (previous plan and actual $M)							
			2013	2014	2015		2016		2017	
			Actual	Actual	Plan	Actual	Plan	Actual	Plan	Forecast
	Common Corporate Costs and Other Costs	Facilities & Real Estate	10.1	20.3	19.0	18.5	15.3	27.6	15.4	19.9
		Information Technology	13.4	17.7	22.6	30.9	20.1	64.2	22.9	56.2
		Other	-2.9	1.5	0.0	0.1	0.0	0.0	0.0	4.3
		Transport and Work, and Service Equipment	43.5	49.1	43.8	52.1	49.1	47.4	44.8	45.0
General Plant Total			**115.3**	**99.9**	**94.8**	**110.1**	**103.3**	**156.3**	**90.1**	**146.3**
Grand Total			**637.0**	**647.5**	**648.9**	**678.3**	**654.7**	**703.2**	**661.4**	**633.5**

Please explain why Information Technology was significantly under forecasted three years in a row (i.e., 2015, 2016 and 2017)?

Response:

In the last distribution rate filing (EB-2013-0416), forecast spend in 2015, 2016 and 2017 for Hydro One distribution-only IT Development projects were based on the assumption that minimal investment related to Customer Experience and Regulatory Compliance would be required post implementation of the new Customer Information System (CIS) in 2014. However, post implementation of CIS, it was deemed necessary to develop an enhanced Customer Strategy as a result of Hydro One's extensive customer engagement exercise. It was Hydro One's first systematic attempt to consult customers specifically on their needs and preferences in a manner that could inform Hydro One's investment plan related to distribution-only IT Development projects. IT project planning estimates are premised on comparable Hydro One business case for a similar size, complex SAP implementation of new functionality and enhancements. IT Development projects that caused over spending in 2015, 2016 and 2017 are detailed in the DSP B1-01-01 Section 3.6 Page: 6, 7 and 8.

OEB Staff Interrogatory # 167

Issue:

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

Reference:

B1-01-01 Section 3.2 Page: 2515 – 2516
Capital Expenditure Forecast, Table 57 – Forecast Test Years Capital Expenditure Breakdown by SDOC

Interrogatory:

System Service Total			**81.8**	**93.4**	**85.6**	**78.8**	**69.5**
General Plant	Development Capital	System Capability Reinforcement	8.2	1.3	0.0	0.0	0.0
	Operations Capital	Operations	16.8	46.4	6.1	6.4	9.1
	Capital Common Corporate Costs and Other Costs	Cornerstone	0.0	0.0	0.0	0.0	0.0
		Facilities & Real Estate	36.5	44.0	38.0	38.0	35.1
		Information Technology	43.2	46.3	42.0	37.9	39.3
		Other	6.6	6.5	6.1	5.8	5.9
Category	**SDOC**	**SDOC Breakdown**	**Test Years (Forecast $M)**				
			2018	**2019**	**2020**	**2021**	**2022**
		Transport and Work, and Service Equipment	37.8	42.5	43.6	45.2	47.3
General Plant Total			**149.0**	**187.1**	**135.8**	**133.4**	**136.6**
Grand Total			**633.9**	**756.8**	**719.0**	**740.7**	**827.2**

a) Under Operations Capital, please explain the large jump in operations costs in 2019.

b) Could this investment be better paced throughout the forecast period to minimize impacts on customer rates? If yes, please provide a proposed pacing and its impacts. If no, please explain why not.

Response:

a) The increase noted is a result of the construction phase of the Integrated System Operations Centre as described in detail in (ISD GP-18).

b) No, as this investment is optimized to meet the 18-months construction schedule.

OEB Staff Interrogatory # 168

Issue:

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

Reference:

B1-01-01 Section 3.7 Page: 2555 - 2560
(5.4.5.1) List of Material Capital Investments Proposed
EB-2013-0416 Exhibit D2/Tab2/Schedule 2 - List of Capital Expenditure Programs/Projects in excess of $1M, Pages 1 – 5

Interrogatory:

Hydro One provided a list of material projects in excess of $1 million in this application and EB-2013-0416. For each capital program, please provide a mapping of this year's investment reference number to EB-2013-0416 investment reference number or state that this is a new type of investment.

Response:

See the table below.

2013 ISD Reference	EB-2013-0416 Name	2017 ISD Reference	EB-2017-0049 Name	New ISD in 2017?
C04	Service Equipment	N/A	Not in Application	
D08	Red Lake TS Capital Contribution	N/A	Not in Application	
IT07	Information Rights Management	N/A	Not in Application	
IT10	Engineering Design Transformation	N/A	Not in Application	
O03	Operating Facilities Refresh	N/A	Not in Application	
C03	Transport and work Equipment	GP01	Transport and Work Equipment	
C1	Real Estate Head Office and GTA Facilities Capital	GP02	Real Estate Facilities Capital	
C2	Real Estate Field Facilities Capital	GP02	Real Estate Facilities Capital	
IT02	MFA Servers and Storage	GP03	MFA Servers and Storage	

2013 ISD Reference	EB-2013-0416 Name	2017 ISD Reference	EB-2017-0049 Name	New ISD in 2017?
IT03	MFA PC and Printer Hardware	GP04	MFA PC and Printer Hardware	
IT01	Hardware/Software Refresh and Maintenance	GP05	Hardware/Software Refresh and Maintenance	
IT04	MFA Telecom Infrastructure	GP06	MFA Telecom Infrastructure	
N/A	Not in EB20130416	GP07	Corporate Performance Reporting	New
N/A	Not in EB20130416	GP08	PCMIS Modernization and Optimization	New
N/A	Not in EB20130416	GP09	ECM - Phase C	New
IT05	Field Workforce Optimization and Mobile IT	GP10	Work Management & Mobility	
IT11	Enterprise GIS	GP11	Enterprise Geographical Information System	
N/A	Not in EB20130416	GP12	Business Process Consolidation	New
N/A	Not in EB20130416	GP13	HR and Pay Related Technology Investments	New
N/A	Not in EB20130416	GP14	Warehouse Scanning Device	New
N/A	Not in EB20130416	GP15	SAP Treasury	New
N/A	Not in EB20130416	GP16	Customer Self Service Technology	New
N/A	Not in EB20130416	GP17	S4 HANA for Finance and Enterprise Asset Management	New
O04	BUCC - New Facilities Development	GP18	Integrated System Operating Centre	
O01	Operating Compute Refresh	GP19	Operating Common Information Technology Infrastructure	

2013 ISD Reference	EB-2013-0416 Name	2017 ISD Reference	EB-2017-0049 Name	New ISD in 2017?
O05	OGCC Storage Area Network Upgrade	GP19	Operating Common Information Technology Infrastructure	
O02	NOMS Refresh	GP20	Network Outage Management System (NOMS) Refresh	
N/A	Not in EB20130416	GP21	Ontario Grid Control Centre Data Centre Remediation	New
N/A	Not in EB20130416	GP22	Ontario Grid Control Centre Office Remediation	New
N/A	Not in EB20130416	GP23	Integrated Voice Communications and Telephony System Refresh	New
C05	Security Infrastructure Capital	GP24	Station Security Upgrades	
D12	Leamington TS Capital Contribution	GP25	Leamington TS Capital Contribution	
D09	Hanmer TS Capital Contribution	GP26	Hanmer TS Capital Contribution	
D10	Enfield TS Capital Contribution	GP27	Enfield TS - Capital Contribution	
IT06	Customer Experience	GP28	Call Centre Technology	
N/A	Not in EB20130416	GP29	Customer Service Billing Investments	New
N/A	Not in EB20130416	GP30	Customer Service Regulatory Changes and Pricing Options	New
N/A	Not in EB20130416	GP31	Collection Enhancements	New
N/A	Not in EB20130416	GP32	Customer Data and Analytics	New
N/A	Not in EB20130416	GP33	Customer Service Complaint Management Tool	New

2013 ISD Reference	EB-2013-0416 Name	2017 ISD Reference	EB-2017-0049 Name	New ISD in 2017?
N/A	Not in EB20130416	GP34	Smart Meter Network Investments	New
IT08	Enterprise Analytics	GP35	Asset Analytics Risk Factor	
D07	Orleans TS Capital Contribution	N/A	Not in Application	
D11	Recloser Retrofit Project	N/A	Not in Application	
IT09	Corporate Support Optimization	N/A	Not in Application	
O06	ORMS Refresh	N/A	Not in Application	
S09	Joint Use and Line Relocations	SA01	Joint Use and Line Relocations Program	
S15	Meter Upgrades	SA02	Meter Infrastructure Sustainment	
S16	Meter Inventory Sustainment	SA02	Meter Infrastructure Sustainment	
N/A	Not in EB20130416	SA03	AMI Network Expansion	New
D01	New Connections, Upgrades and Service Cancellations	SA04	New Load Connections, Service Upgrades, Cancellations and Metering	
N/A	Not in EB20130416	SA05	Generation Connections	New
S03	Spill Containment	N/A	Not in Application	
S06	Demand Work	SR01	Distribution Station Demand Program	
S02	Mobile Unit Substations	SR02	Mobile Unit Substations Program	
S01	Transformer Spares and Replacements	SR03	Station Spare Transformer Purchases	
S04	Station Component Replacements	SR04	Distribution Station Component Planned Replacement Program	
S05	Recloser Upgrades	SR05	Distribution Station Reclosers Upgrade	

2013 ISD Reference	EB-2013-0416 Name	2017 ISD Reference	EB-2017-0049 Name	New ISD in 2017?
S07	Station Refurbishments	SR06	Distribution Station Refurbishments	
S08	Trouble Call and Storm Damage Response	SR07	Distribution Lines Trouble Call and Storm Damage Distribution Lines Trouble Call and Storm Damage Response Program	
S11	PCB Lines Equipment Replacements	SR08	Distribution Lines PCB Equipment Replacement Program	
S10	Pole Replacements	SR09	Pole Replacement Program	
S13	Line Component Replacements	SR10	Distribution Lines Planned Component Replacement	
S14	Submarine Cable Replacements	SR11	Component Replacement Submarine Cable	
S12	Large Sustainment Initiatives	SR12	Distribution Lines Sustainment Initiatives	
D05	Asset Lifecycle Optimization and Operational Efficiency	SR13	Life Cycle Optimization and Operational Efficiency Projects	
N/A	Not in EB20130416	SR14	AMI Hardware Refresh	New
N/A	Not in EB20130416	SS01	Remote Disconnection Reconnection Program	New
D02	Upgrades Driven by Load Growth	SS02	System Upgrades Driven by Load Growth	
D06	Reliability Improvements	SS03	Reliability Improvements	
D04	Upgrades Driven by Load Growth - Demand Investments	SS04	Demand Investments	
D03	Upgrades Driven by Load Growth - Distribution System modifications	SS05	Distribution System Modifications	

2013 ISD Reference	**EB-2013-0416 Name**	**2017 ISD Reference**	**EB-2017-0049 Name**	**New ISD in 2017?**
N/A	Not in EB20130416	SS06	Worst Performing Feeders Program	New
EB-2013-0416 - Exhibit D1,Tab 3, Schedule 5 (Customer Services Capital)		SS07	Advanced Distribution System	

OEB Staff Interrogatory # 169

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2578
(5.4.5.2) Attachments: Material Investments, ISD: SA-04 New Load Connections, Upgrades, Cancellations and Metering

Interrogatory:

*"**Investment Need:***
Hydro One is obligated to connect new customers to the distribution network, upgrade services for existing customers, and install meters for new services under Hydro One's Distribution License. These system investments include the following activities:

New Connections: As part of its obligations under Hydro One's electricity distribution license and the distributor's responsibilities in the Distribution System Code ("DSC"), Hydro One is required to make an offer to connect all distribution customers on a non-discriminatory basis, upon written request for connection.

Service Upgrades: A service upgrade occurs when a customer requires a larger service entrance. A service upgrade normally requires the preparation of a service layout and replacement of secondary service lines. Transformers may also have to be upgraded, meters replaced and possibly additional transformation installed.

Metering: Installations may be required for new connections and service upgrades. Revenue meters, are funded under this program for new connections and service upgrades.

Cancellations: For cancellations of existing service, Hydro One is required to remove idle assets (such as transformers, poles, wires and meters) for safety and security reasons."

a) Please provide the historical budgeted and actual Net Investment Cost for the last three years. Provide explanation for all material variances.

b) How does Hydro One redirect excess budget in this investment?

Witness: GARZOUZI Lyla

Response:

a) The historical OEB Approved and actual Net Investment Costs for the last three years are provided in the table below.

Year	OEB Approved ($M)	Actual ($M)	Variance ($M)	Variance (%)
2014	1	111.3	1	1
2015	108.9	113.9	5.1	5%
2016	112.1	108.2	-3.9	-3%

Note 1: Since 2014 rates were set via a 3GIRM application, there is no specific OEB approved amount for 2014.

This program is driven by customer connection, upgrade and cancellation requests, with cost variances resulting from the actual number, and type of connections, service upgrades and service cancellations that materialize in a given year.

There was no OEB approved budget in 2014 as rates were set via 3GIRM. As such no variance has been presented for 2014.

The 2015 variance was due to higher than forecast costs associated with large customer expansions, and higher than forecast service upgrade costs, which were partially offset by lower than forecast new connection design costs and lower than forecast revenue metering costs.

The 2016 variance was due to lower than forecast new customer connection costs and lower than forecast revenue metering costs, which was partially offset by higher than forecast service upgrade costs.

b) Hydro One monitors all investments on an ongoing basis and redirects funds as necessary between investments. Hydro One's current process for redirecting funds between investments is outlined in DSP Section 2.1, Sections 2.1.6.3 and 2.1.6.4.

OEB Staff Interrogatory # 170

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2587
(5.4.5.2) Attachments: Material Investments, ISD: SR-01 Distribution Stations Demand Capital Program

Interrogatory:

*"**Investment Need:***

> *Service interruptions or unplanned system deficiencies associated with various distribution station assets occur and require an immediate response by Hydro One personnel. Asset failure or extreme weather may result in service interruptions that require restoration of power to maintain reliability. Over the past five years, there has been an average of 59 interruptions per year related to station equipment."*

a) Is the annual interruption count growing, shrinking or remaining the same from year to year?

b) Is the annual interruption count linked to weather?

Response:

a) The annual interruption count has been shrinking from 2014 to 2016.

b) The annual interruption data used included events which would be attributed to weather.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 171

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2591
(5.4.5.2) Attachments: Material Investments, ISD: SR-02 Mobile Unit Substation Program

Interrogatory:

"Alternative 4: Planned Full MUS Replacements and Fleet Expansion (Recommended)

Replace six MUS's at end-of-life to address the condition of the existing fleet identified as high risk, and expand the fleet with the procurement of three additional MUS's to address the shortfall in the MUS fleet. This alternative is recommended as it attempts to address the immediate needs identified for the MUS fleet to ensure system reliability is maintained and begins to alleviate backlog by making strategic expansion to the fleet."

a) Please provide in Excel format a list of all Mobile Unit Substations (MUS). The list should include each MUS's designation, technical specifications, age, and asset analytic data.

b) Please highlight in the provided list the MUS's that will be replaced and provide the same information for each new MUS.

c) Please provide historical MUS cost per unit for the last three years.

Response:

a) Please refer to Attachment 1 to this response for the list of Mobile Unit Substations ("MUS").

b) The MUS's planned for replacement in the 2018 to 2022 plan are highlighted in yellow, and the MUS's to be purchased are highlighted in grey in Attachment 1 to this response.

c) Hydro One has recently purchased two MUS's, namely MUS40 and MUS41. The cost of these MUS's was $3.7 million per unit.

	MUS Specifications				MUS Transformer				MUS Trailer			Investment Plan ISD: SR-02
MUS Name	**MVA**	**ULTC**	**Primary Voltages (kV)**	**Secondary Voltages (kV)**	**Year Built**	**Age**	**Life Remaining**	**Composite Score (Asset Analytics)**	**Year Built**	**Age**	**Life Remaining**	
MUS1	4.2	no	44 / 22	12.47 / 8.32 / 4.16	1965	53	beyond ESL	26	2010	8	17	
MUS2	5	yes	27.6 / 13.8	8.32 / 4.16	1978	40	0	54	2009	9	16	
MUS3	7	no	44 / 22	12.47 / 8.32 / 4.16	1965	53	beyond ESL	26	2006	12	13	
MUS4	5	no	27.6 / 13.8	8.32 / 4.16	1961	57	beyond ESL	26	2003	15	10	
MUS5	5	no	27.6 / 13.8	8.32 / 4.16	1966	52	beyond ESL	30	2006	12	13	
MUS6	5	no	44 / 22	12.47 / 8.32 / 4.16	1966	52	beyond ESL	1	2011	7	18	
MUS7	4	no	44 / 22	12.47 / 8.32 / 4.16	1956	62	beyond ESL	29	2007	11	14	
MUS8	7	yes	44	12.47 / 8.32 / 4.16	1977	41	beyond ESL	55	1977	41	beyond ESL	To be replaced in 2020. New MUS specification: 10 MVA, 44kV - 12.47 / 8.32 kV with ULTC
MUS9	5	no	27.6	8.32 / 4.16	1968	50	beyond ESL	1	2004	14	11	
MUS17	4.2	no	44 / 22	12.47 / 8.32 / 4.16	1968	50	beyond ESL	26	2011	7	18	
MUS20	4	no	44 / 22	12.47 / 8.32 / 4.16	1966	52	beyond ESL	30	2008	10	15	
MUS21	5	no	27.6 / 13.8	8.32 / 4.16	1961	57	beyond ESL	26	2001	17	8	
MUS22	7	yes	44 / 22	12.47	1969	49	beyond ESL	29	2006	12	13	
MUS23	7	yes	44	12.47 / 8.32 / 4.16	1969	49	beyond ESL	54	2000	18	7	
MUS24	7	yes	44 / 27.6	12.47 / 8.32 / 4.16	1970	48	beyond ESL	44	1970	48	beyond ESL	To be replaced in 2019. New MUS specification: 10 MVA, 44kV - 12.47 / 8.32 kV with ULTC
MUS25	7	yes	44 / 27.6	12.47 / 8.32 / 4.16	1970	48	beyond ESL	35	2009	9	16	
MUS26	**7**	**yes**	**44 / 27.6**	**12.47 / 8.32 / 4.16**	**1970**	**48**	**Failed**	**Failed**	**1970**	**48**	**Retired**	To be replaced in 2018 **(Failed).** New MUS specification: 7.5 MVA, 27.6kV - 8.32 kV with ULTC
MUS27	7	yes	44 / 27.6	12.47 / 8.32 / 4.16	1970	48	beyond ESL	54	2011	7	18	
MUS28	7	yes	44 / 27.6	12.47 / 8.32 / 4.16	1970	48	beyond ESL	44	1970	48	beyond ESL	To be replaced in 2020. New MUS specification: 10 MVA, 44kV - 12.47 / 8.32 kV with ULTC
MUS29	15	yes	115	27.6 / 25 / 13.8 / 12.47 / 8.32	1983	35	5	48	2014	4	21	
MUS30	15	yes	115	27.6 / 25 / 13.8 / 12.47 / 8.32	1983	35	5	38	1983	35	beyond ESL	To be replaced in 2021. New MUS specification: 15 MVA, 115kV - 27.6 / 25 / 12.47 / 8.32 kV with ULTC
MUS31	15	yes	44	27.6 / 25 / 13.8 / 12.47 / 8.32	1984	34	6	19	1984	34	beyond ESL	
MUS32	7	yes	44	27.6 / 25 / 13.8 / 12.47 / 8.32	1986	32	8	21	2013	5	20	
MUS33	15	yes	44	27.6 / 25 / 13.8 / 12.47 / 8.32	1988	30	10	31	1988	30	beyond ESL	
MUS34	15	yes	115	27.6 / 25 / 13.8 / 12.47 / 8.32	1989	29	11	40	1989	29	beyond ESL	
MUS35	**9**	**yes**	**44 / 27.6**	**12.47 / 8.32**	**1991**	**27**	**Failed**	**Failed**	**1989**	**29**	**Retired**	To be replaced 2018 **(Failed).** New MUS specification: 10 MVA, 44kV - 12.47 / 8.32 kV with ULTC
MUS36	9	yes	44 / 27.6	12.47 / 8.32	1989	29	11	41	2011	7	18	
MUS37	15	yes	44 / 27.6	12.47 / 8.32	1992	26	14	28	1992	26	beyond ESL	
MUS40	20	yes	115	27.6 / 25 / 12.47 / 8.32	2013	5	35	1	2014	4	21	
MUS41	15	yes	115	25 / 12.47	2016	2	38	1	2016	2	23	
MUS42	5	no	27.6	8.32 / 4.16	2008	10	30	0	2008	10	15	
New MUS	10	yes	44	12.47 / 8.32								To be purchased in 2021
New MUS	10	yes	44	12.47 / 8.32								To be purchased in 2022
New MUS	7.5	yes	27.6	8.32								To be purchased in 2022

OEB Staff Interrogatory # 172

Issue:

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

Reference:

B1-01-01 Section 3.8 Page: 2601
(5.4.5.2) Attachments: Material Investments, ISD: SR-03 Station Spare Transformer Purchases Program

Interrogatory:

"Costs:
The factors which affect the costs in this investment are the following:

- *The actual number of transformer failures and demand transformer replacements which occur in year that require spare deployment; and*
- *The type of transformer requiring spare deployment, as the costs of the spare transformers can vary based on transformer specifications such as: voltage, capacity and tap-changer requirements."*

a) Please provide details of the total inventory of spare transformers, the number taken out of inventory and the number added to inventory for each of the historical years.

b) Please explain why 150 spare transformers are required in inventory when only 9 are expected to be used each year.

c) Please provide in Excel format a list of all spare transformers. The list should include each transformer's technical specification, age, date of purchase, and asset analytic data.

Response:

a) Details of the total inventory of spare transformers, the number removed and the number added for each historical year are in the following table:

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Spare transformers added to Inventory	26	29	22	30	5	4
Project transformers added to inventory for planned replacements	1	0	0	10	2	1
Total transformers added	**27**	**29**	**22**	**40**	**7**	**5**
Spares deployed to unplanned projects	5	11	12	5	7	13
Spares deployed to planned projects	8	9	8	8	3	5
Total spare transformers deployed to planned and unplanned projects	**13**	**20**	**20**	**13**	**10**	**18**
Spares identified to be scrapped	**57**	**4**	**17**	**58**	**0**	**12**
Net Increase / Decrease	-43	5	-15	-31	-3	-25
Total spares in Inventory *(including Operating Spares and Engineering Reserves available for projects)*	**208**	**213**	**198**	**167**	**164**	**139**[1]

b) The 149 transformers referenced in ISD: SR-03 was a combination of operating spare transformers (99) and transformers available for planned project usage (50). The transformers available for project usage will be allocated to planned and demand projects (identified under SR-06 and SR-01) to reduce the total inventory as opportunities arise.

The 99 spare transformers are required to satisfy a station transformer population with 48 unique categories. Hydro One is working towards reducing the number of spare categories to 27. However, until these categories can be eliminated, spares must be retained for all 48 categories.

c) An excel list provided as Attachment 1, contains the 2017 list of operating spares (93) and transformers available for project usage (46). Hydro One maintains condition and demographics data for spare transformers; however asset analytic algorithms have not been defined for spare equipment.

[1] *In SR-03, the indicated spare count of 164 spares in 2018 was based on the forecast status as of year-end 2016. In 2017 Hydro One made further progress than planned on reducing spare count.*

Status	Transformer Serial Number	SAP Equipment Number	Transformer Class	MVA	Phase	Nom HV	Nom LV1	Nom LV2	ULTC	Year Built	Age
Operating Spare	G2927-05	2785032	DS Transformer	7.5	Three	27.6	8.8		ULTC	2012	5
Operating Spare	S-35932	3029752	DS Transformer	7.5	Three	27.6	8.8		ULTC	2013	4
Operating Spare	G3189-04	3087905	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2015	2
Operating Spare	G3189-10	3093858	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2015	2
Operating Spare	G3189-11	3100160	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2015	2
Operating Spare	G3189-12	3111903	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2015	2
Operating Spare	G3189-07	3088363	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2015	2
Operating Spare	G3341-03	3093857	DS Transformer	5	Three	44	8.8	4.4	ULTC	2015	2
Operating Spare	G3341-04	3094919	DS Transformer	5	Three	44	8.8	4.4	ULTC	2015	2
Operating Spare	G3341-05	3111902	DS Transformer	5	Three	44	8.8	4.4	ULTC	2015	2
Operating Spare	G3341-06	3140205	DS Transformer	5	Three	44	8.8	4.4	ULTC	2016	1
Operating Spare	SL16459-001	1249630	DS Transformer	5	Three	44	8.32	4.16	ULTC	2005	12
Operating Spare	G3167-06	3093633	DS Transformer	10	Three	44	13.2		ULTC	2015	2
Operating Spare	G3167-03	3055099	DS Transformer	10	Three	44	13.2		ULTC	2014	3
Operating Spare	G3167-05	3057873	DS Transformer	10	Three	44	13.2		ULTC	2014	3
Operating Spare	G3191-01	3063127	DS Transformer	20/27/33	Three	115.5	29.3		ULTC	2014	3
Operating Spare	S14622-01	1234809	DS Transformer	10	Three	44	8.32		ULTC	1990	27
Operating Spare	N36095	3078540	DS Transformer	10	Three	44	8.8		ULTC	2014	3
Operating Spare	N36228	3123438	DS Transformer	7.5	Three	44	26.5		ULTC	2015	2
Operating Spare	N36229	3129432	DS Transformer	10/13/16	Three	44	29.3		ULTC	2015	2
Operating Spare	N36230	3129431	DS Transformer	10/13/16	Three	44	29.3		ULTC	2015	2
Operating Spare	G1176-01	1234891	DS Transformer	7.5	Three	44	8.8		ULTC	2003	14
Operating Spare	G2767-02	2383747	DS Transformer	7.5	Three	44	8.8		ULTC	2011	6
Operating Spare	G3577-01	3161401	DS Transformer	5	Three	13.8	8.32		ULTC	2016	1
Operating Spare	G3071-05	3029171	DS Transformer	7.5	Three	44	13.2		ULTC	2013	4
Operating Spare	A32S0210	1233924	DS Transformer	10	Three	44	26.5		ULTC	1992	25
Operating Spare	5264/1	1306898	DS Transformer	10	Three	44	27.6		ULTC	1978	39
Operating Spare	G3213-01	3094910	DS Transformer	7.5/10/12.5	Three	115.5	8.8		ULTC	2015	2
Operating Spare	G2925-02	3029125	DS Transformer	7.5/10/12.5	Three	115.5	13.2		ULTC	2013	4
Operating Spare	G3075-03	3029128	DS Transformer	7.5/10/12.5	Three	115.5	13.2		ULTC	2013	4
Operating Spare	214101108	3070309	DS Transformer	7.5/10/12.5	Three	115.5	26.5		ULTC	2014	3
Operating Spare	215091131	3124969	DS Transformer	7.5/10/12.5	Three	115.5	26.5		ULTC	2015	2
Operating Spare	214101109	3070310	DS Transformer	15/20/25	Three	115.5	29.3		ULTC	2014	3
Operating Spare	1-4173	1233710	DS Transformer	15	Three	115	27.6		ULTC	1979	38
Operating Spare	AS41631-002	3042509	DS Transformer	7.5	Three	27.6	8.8		NO	2014	3
Operating Spare	HC15598-001	1232217	DS Transformer	10	Three	44	29.3		NO	2004	13

Status	Transformer Serial Number	SAP Equipment Number	Transformer Class	MVA	Phase	Nom HV	Nom LV1	Nom LV2	ULTC	Year Built	Age
Operating Spare	T104111	3113670	DS Transformer	5	Three	44	8.8	4.4	NO	2015	2
Operating Spare	284241	1139412	DS Transformer	5	Three	44	8.32		NO	1976	41
Operating Spare	G12639-1	1234388	DS Transformer	10/13/16	Three	44	13.8		NO	2003	14
Operating Spare	D140555	3066099	DS Transformer	1	Three	44	0.2		NO	2014	3
Operating Spare	T104100	3091274	DS Transformer	7.5	Three	44	8.8	4.4	NO	2015	2
Operating Spare	G3210-01	3045030	DS Transformer	7.5	Three	44	8.8	4.4	NO	2014	3
Operating Spare	G3070-01	3024936	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Operating Spare	G3070-02	3024937	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Operating Spare	G3070-04	3024939	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Operating Spare	G3070-06	3025761	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Operating Spare	BS41632-006	3065251	DS Transformer	7.5	Three	44	13.2		NO	2014	3
Operating Spare	BS41632-002	3042511	DS Transformer	7.5	Three	44	13.2		NO	2014	3
Operating Spare	60705	1126901	DS Transformer	6	Three	44	25		NO	1987	30
Operating Spare	D141002	3055212	DS Transformer	1	Three	27.6	0.6		NO	2014	3
Operating Spare	D141003	3055147	DS Transformer	1	Three	27.6	0.6		NO	2014	3
Operating Spare	2-302710	1250903	DS Transformer	1	Three	27.6	0.6		NO	1972	45
Operating Spare	D140551	3057804	DS Transformer	1	Three	44	0.6		NO	2014	3
Operating Spare	608101001	1235042	DS Transformer	1	Three	44	0.6	0.347	NO	1986	31
Operating Spare	2-304715	2376714	DS Transformer	1	Three	44	0.6		NO	1975	42
Operating Spare	2-303449	1234380	DS Transformer	1	Three	44	0.6		NO	1973	44
Operating Spare	T103106	3046258	DS Transformer	5	Three	27.6	8.32	4.4	NO	2014	3
Operating Spare	09-2341	1367968	DS Transformer	5	Three	27.6	8.32	4.16	NO	2010	7
Operating Spare	T103131	3064133	DS Transformer	5	Three	27.6	8.32	4.4	NO	2014	3
Operating Spare	T103130	3064258	DS Transformer	5	Three	27.6	8.32	4.4	NO	2014	3
Operating Spare	T104101	3094208	DS Transformer	5	Three	27.6	8.8	4.4	NO	2015	2
Operating Spare	T102138	3029132	DS Transformer	10	Three	44	8.8		NO	2013	4
Operating Spare	T102136	3029134	DS Transformer	10	Three	44	8.8		NO	2013	4
Operating Spare	T104117	3111986	DS Transformer	10	Three	44	8.8		NO	2015	2
Operating Spare	T104102	3094748	DS Transformer	10	Three	44	13.2		NO	2015	2
Operating Spare	G2931-05	2752655	DS Transformer	10	Three	44	13.2		NO	2012	5
Operating Spare	G2931-06	2784911	DS Transformer	10	Three	44	13.2		NO	2012	5
Operating Spare	97043161	1234406	DS Regulator	40	Three	44	44		ULTC	2004	13
Operating Spare	1-3138	1252240	DS Regulator	3	Three	8.32	8.32		ULTC	1968	49
Operating Spare	N36389	3173630	DS Regulator	25	Three	44	44		ULTC	2016	1
Operating Spare	N36400	3196058	DS Regulator	25	Three	44	44		ULTC	2017	0
Operating Spare	97043159	1234404	DS Regulator	40	Three	27.6	27.6		ULTC	2004	13

Status	Transformer Serial Number	SAP Equipment Number	Transformer Class	MVA	Phase	Nom HV	Nom LV1	Nom LV2	ULTC	Year Built	Age
Operating Spare	N36169	3100867	DS Regulator	25	Three	27.6	27.6		ULTC	2015	2
Operating Spare	G14877-1	1306461	DS Regulator	25	Three	27.6	27.6		ULTC	2008	9
Operating Spare	G10919-1	1127003	DS Regulator	25	Three	27.6	27.6		ULTC	2000	17
Operating Spare	1-3075	1134533	DS Regulator	6	Three	25	25		ULTC	1967	50
Operating Spare	1-3467	1131290	DS Regulator	6	Three	13.8	13.8		ULTC	1970	47
Operating Spare	N36170	3114523	DS Regulator	10	Three	12.47	12.47		ULTC	2015	2
Operating Spare	60226-1	1134611	DS Regulator	6	Three	12.47	12.47		ULTC	1976	41
Operating Spare	1-2155	1122998	DS Regulator	3	Three	12.47	12.47		ULTC	1964	53
Operating Spare	3060-2	1252273	DS Transformer	2	Single	115.5	15.48		NO	1967	50
Operating Spare	3060-1	2376715	DS Transformer	2	Single	115.5	15.48		NO	1967	50
Operating Spare	287031	1251701	DS Transformer	2	Single	115.5	12.47		NO	1969	48
Operating Spare	3561-2	1368137	DS Transformer	1	Single	115	12.47		NO	1968	49
Operating Spare	179150	1250269	DS Transformer	1	Single	115.5	8.32		NO	1951	66
Operating Spare	218152	1120860	DS Transformer	1	Single	13.8	7.2		NO	1964	53
Operating Spare	N36149	3077412	DS Transformer	7.5	Three	44	13.2		ULTC	2015	2
Operating Spare	47010MA322-C249A	3070302	DS Transformer	10	Three	44	29.3		NO	2014	3
Operating Spare	A3S6806	3193975	DS Transformer	5	Three	27.6	8.32		NO	1998	19
Operating Spare	2-350414	1234886	DS Transformer	3	Three	27.6	12.47		NO	1982	35
Operating Spare	477500A204-C426A	3123078	DS Transformer	7.5	Three	44	4.4		NO	2015	2
Operating Spare	N36402	3196057	DS Regulator	25	Three	44	44		ULTC	2017	0
Operating Spare	N36404	3187793	DS Regulator	10	Three	12.47	12.47		ULTC	2017	0
Engineering Reserve - Available	G3189-01	3070300	DS Transformer	5	Three	27.6	8.8	4.4	ULTC	2014	3
Engineering Reserve - Available	1-3558	1141865	DS Transformer	5	Three	27.6	8.32		ULTC	1971	46
Engineering Reserve - Available	1-3638	1122679	DS Transformer	5	Three	27.6	8.32		ULTC	1971	46
Engineering Reserve - Available	T-60233-1	1306623	DS Transformer	5	Three	27.6	8.32		ULTC	1975	42
Engineering Reserve - Available	T-60344-1	1368119	DS Transformer	5	Three	44	8.32		ULTC	1978	39
Engineering Reserve - Available	1621901003	1233695	DS Transformer	20/27/33	Three	115.5	29.3		ULTC	1993	24
Engineering Reserve - Available	N36094	3077587	DS Transformer	10	Three	44	8.8		ULTC	2014	3
Engineering Reserve - Available	B32S0215	3066059	DS Transformer	7.5	Three	44	8.32		ULTC	1992	25
Engineering Reserve - Available	G3073-02	3027768	DS Transformer	7.5/10/12.5	Three	115.5	8.8		ULTC	2013	4
Engineering Reserve - Available	G3075-01	3029127	DS Transformer	7.5/10/12.5	Three	115.5	13.2		ULTC	2013	4
Engineering Reserve - Available	A32S0209	1249784	DS Transformer	7.5/10/12.5	Three	115.5	26.5		ULTC	1992	25
Engineering Reserve - Available	G3190-01	3063126	DS Transformer	7.5/10/12.5	Three	115.5	26.5		ULTC	2014	3
Engineering Reserve - Available	S15430-01	1234808	DS Transformer	15/20/25	Three	115.5	29.5		ULTC	1991	26
Engineering Reserve - Available	G2927-04	2766802	DS Transformer	7.5	Three	27.6	8.8		ULTC	2012	5
Engineering Reserve - Available	A32S0256	1247455	DS Transformer	7.5	Three	27.6	8.32		NO	1993	24

Status	Transformer Serial Number	SAP Equipment Number	Transformer Class	MVA	Phase	Nom HV	Nom LV1	Nom LV2	ULTC	Year Built	Age
Engineering Reserve - Available	12-2453	2776574	DS Transformer	7.5	Three	27.6	8.8		NO	2012	5
Engineering Reserve - Available	12-2454	2776575	DS Transformer	7.5	Three	27.6	8.8		NO	2012	5
Engineering Reserve - Available	AS41631-001	3042368	DS Transformer	7.5	Three	27.6	8.8		NO	2014	3
Engineering Reserve - Available	G1840-01	2376663	DS Transformer	6	Three	115.5	13.2		NO	2006	11
Engineering Reserve - Available	4105/1	1234907	DS Transformer	5	Three	44	4.16		NO	1979	38
Engineering Reserve - Available	G3070-07	3029118	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Engineering Reserve - Available	G3070-08	3029119	DS Transformer	7.5	Three	44	8.8	4.4	NO	2013	4
Engineering Reserve - Available	G2490-02	2383763	DS Transformer	7.5	Three	44	8.8		NO	2011	6
Engineering Reserve - Available	B32S-0213	1233931	DS Transformer	7.5	Three	44	8.8		NO	1992	25
Engineering Reserve - Available	60253-3	1234806	DS Transformer	0.667	Three	27.6	0.2		NO	1977	40
Engineering Reserve - Available	D141004	3055214	DS Transformer	1	Three	27.6	0.6		NO	2014	3
Engineering Reserve - Available	D140552	3057800	DS Transformer	1	Three	44	0.6		NO	2014	3
Engineering Reserve - Available	D140553	3057871	DS Transformer	1	Three	44	0.6		NO	2014	3
Engineering Reserve - Available	D140554	3057872	DS Transformer	1	Three	44	0.6		NO	2014	3
Engineering Reserve - Available	12-2446	2756396	DS Transformer	1	Three	44	0.6		NO	2012	5
Engineering Reserve - Available	N36086	3077411	DS Transformer	5	Three	27.6	8.8	4.4	NO	2014	3
Engineering Reserve - Available	14469-001	1234888	DS Transformer	6	Three	27.6	4.16		NO	2003	14
Engineering Reserve - Available	HC15597-001	1945896	DS Transformer	10	Three	44	8.8		NO	2004	13
Engineering Reserve - Available	T102137	3029130	DS Transformer	10	Three	44	8.8		NO	2013	4
Engineering Reserve - Available	T102139	3029131	DS Transformer	10	Three	44	8.8		NO	2013	4
Engineering Reserve - Available	2-307017	1131872	DS Transformer	6	Three	44	12.47		NO	1979	38
Engineering Reserve - Available	G2931-04	2752815	DS Transformer	10	Three	44	13.2		NO	2012	5
Engineering Reserve - Available	1568401003	1233720	DS Transformer	10	Three	44	13.2		NO	1992	25
Engineering Reserve - Available	1568401006	1306541	DS Transformer	10	Three	44	13.2		NO	1992	25
Engineering Reserve - Available	T102140	3029129	DS Transformer	10	Three	44	13.2		NO	2013	4
Engineering Reserve - Available	T-60594-1	1126362	DS Regulator	25	Three	27.6	27.6		ULTC	1984	33
Engineering Reserve - Available	G12023-1	1126590	DS Regulator	25	Three	27.6	27.6		ULTC	2002	15
Engineering Reserve - Available	T60824	1143496	DS Transformer	25	Three	27.6	27.6		ULTC	1990	27
Engineering Reserve - Available	2467-1	1232221	DS Regulator	25	Three	27.6	27.6		ULTC	1971	46
Engineering Reserve - Available	N36171	3114524	DS Regulator	10	Three	12.47	12.47		ULTC	2015	2
Engineering Reserve - Available	61-02-6A543	1367969	DS Transformer	10	Three	115	13.8		ULTC	1993	24

OEB Staff Interrogatory # 173

Issue:

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

Reference:

Q-01-01
1.2 A reduction in the capital forecast; updated rate base and in-service additions forecasts

Interrogatory:

Hydro One has updated the capital forecast for the years 2018-2022 due to adjustments made to General Plant projects and productivity targets.

Please provide the updated ISD for each General Plant investment that has affected the updated capital forecast and highlight the changes in project scope or explain the productivity change that attributed to the updated capital forecast.

Response:

The attachment to this response includes the following updated ISDs:

- GP-01
- GP-02
- GP-03
- GP-04
- GP-05
- GP-06
- GP-07
- GP-08
- GP-09
- GP-10
- GP-11
- GP-12
- GP-13
- GP-14
- GP-15
- GP-17

- GP-18
- GP-19
- GP-20
- GP-23
- GP-35

Additionally it includes the following newly created ISDs as a result of the updated capital forecast presented in Exhibit Q, Tab 1, Schedule 1:

- GP-36
- GP-37
- GP-38
- GP-39
- GP-40

GP-01 Transport & Work Equipment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	201.0158.0
Primary Trigger:	F1-Asset renewal / maintenance		
Secondary Trigger:	Capital Program		

Investment Need:

Hydro One controls and manages approximately 7,200 Fleet vehicles which support the various lines of business, including Distribution and Transmission Lines, Stations Services, Forestry and Stations Construction. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These include, but are not limited to CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. This results in minimized environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

Transport and Work Equipment ("TWE" or "Fleet") expenditures for 2018 through 2022 are primarily required to replace end of life core TWE;

Alternatives:

TWE plays a wide reaching and integral role in the day-to-day operations, safety and success at Hydro One. Availability of TWE has a direct impact on work programs and this proposal is to maintain the Fleet complement at its current levels.

The primary alternative to the proposed plan centres on a reduction in capital spending on TWE in favour of increased use of rental equipment, if the required equipment is available, and extended retention of existing equipment to satisfy work program and staffing requirements. Hydro One employs specialized equipment specifically outfitted to Hydro One safety specifications. Short term rentals are utilized where applicable on light duty vehicles but history has shown that due to the nature of the work, any rental savings is quickly offset by additional costs incurred by the normal wear and tear on the rental vehicles in this type of industry. The result is increased maintenance costs on the retained vehicles, increased vehicle downtime and decreased equipment availability.

Investment Description:

Fleet capital replacement requirements are based on:

1. Industry standards (manufacturer's recommendations) for life cycle expectancy;
2. Net Book Value (NBV) to Original Capital Value (OCV) ratios; and
3. Operating cost drivers which are then linked to the Business Plan and Work Programs.

Currently, the fleet is at 39% NBV to OCV where industry standards, established through a combination of Canadian Utility Fleet Manager workshops, direction from Fleet Management Companies and Industry experts, suggest that 45% as an optimum level. Our present replacement criteria are based on manufacturers' recommendations and repair history.

Key contributors to the 2018-2022 capital program include:

- The replacement of core transport and work equipment (about 7%, approximately 500 vehicles, of Fleet annually);
- Replacement of aging helicopters.

Table 1 – Forecast of Acquisitions for 2018 to 2022

Equipment Type	2018		2019		2020		2021		2022	
	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units
Light[1]	3.7	292	6.4	294	7.7	331	7.7	334	7.8	336
Heavy[2]	11.0	77	10.4	77	12.5	87	12.6	88	12.7	88
Off-Road[3]	5.3	21	5.0	22	6.0	24	6.0	25	6.1	25
Miscellaneous[4]	3.6	140	3.4	141	4.1	159	4.1	160	4.2	161
Helicopter	0	0	4.7	1	0.	0	0	0	0	0
Service Equipment [5]	2.5	12	1.9	9	1.9	9	1.9	9	2.0	9
Total	**29.1**	**542**	**31.8**	**543**	**32.1**	**611**	**32.4**	**615**	**32.6**	**620**

Note: Number of units is based on average unit costs per category of equipment and is subject to change based on specific LOB staff and the right-sizing initiative being completed by Fleet Management Service to reduce the Fleet complement by analysing the Telematics utilization data.
Numbers of units are based on the Tx and Dx Capital Investment Costs.

[1]Light – cars, SUVs, pickups, vans
[2]Heavy – service trucks, highway tractors, radial boom derricks (RDB), bucket trucks

[3]Off Roads – rubber tire, tracked equipment
[4]Miscellaneous – boats, chippers, tensioners, manlifts, forklifts
[5] Service Equipment – UTVs, snowmobiles
Incremental Additions – Due to right sizing initiatives there are no incremental additions in this planning period.

Risk Mitigation:

Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers.

Light vehicles are replaced after six years or 180,000 km. Heavy vehicles have several replacement guidelines depending on the type of equipment; service trucks are replaced after six years or 300,000 km, and work equipment-single axle is replaced after eight to ten years or 400,000 km. Work equipment-tandem axle is replaced after twelve to fourteen years or 400,000 km. Off-Road and Miscellaneous equipment is replaced on a case by case basis depending on utilization and condition of the equipment and ongoing need.

Helicopters are replaced on a case by case basis depending on utilization, condition of the aircraft and the cost of refurbishment.

This asset strategy is designed to address the following risks:

- Equipment failure - Retaining and operating older equipment increases the probability of failure, which creates costly downtime for crews and increases safety risk for employees and the public;
- Scheduled Outages - Customers (especially large industrial) are impacted when equipment is unavailable because the outage must be rescheduled;
- Emergency response - Unplanned work (i.e., storm response, trouble calls) requires timely dispatch and lack of available equipment will impact customers by exacerbating outages;
- Work Schedules - Delay in work programs impact the Line of Business (LOB) project costs and decrease operational effectiveness;
- Increasing costs - Repair time and maintenance costs are reduced since aging equipment requires more maintenance; and
- Environmental goals - Environmental Impact to the public is affected by operating aging equipment as newer, maintained vehicles tend to have a lower carbon footprint.

Result:

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process and to plan for future TWE requirements based on work program and staffing forecasts. The TWE Replacement Program annually analyzes its five-year business planning cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital replacement program, on an annual basis, is evaluated against the business plan and is subject to the LOB's work program prioritization and forecasting process.

The objective is to maintain a stable fleet replacement program and minimize capital investment fluctuations year-over-year. A reduction in capital spent in a given year will result in increased operating costs, which could ultimately result in increased equipment rates.

This investment will:

- Ensure compliance with all safety standards, as well as Ministry of Transportation (MTO) and regulatory requirements;
- Fleet Services will leverage Telematics data to institute baseline metrics with respect to equipment utilization and productivity;
- Maximize productivity efficiencies and utilization; and
- Optimize repair time with minimal downtime
- Ensure optimal Fleet complement.

Outcome Summary:

Customer Focus	• Optimize Fleet Service levels to mitigate potential delays in response time to unplanned incidents, such as trouble calls and storm response.
Operational Effectiveness	• Fleet vehicles and other specialized equipment at optimal levels of availability reduce human effort and minimize risk of personal injury. • Optimal investment levels allow employees to have the right equipment to do their job, increase employee engagement levels, minimize risk of injury and increase work satisfaction.

Witness: Rob Berardi

Public Policy Responsiveness	• Optimal investment levels allow for maximum equipment efficiencies and minimize Hydro One's carbon footprint. • Ensure compliance with all codes, standards and regulations to maximize shareholder value and sustainably manage our environmental footprint. • Vehicles will be maintained at an optimum level to ensure public and employee safety and to meet Ministry regulations.
Financial Performance	• Ensure savings from operational effectiveness are sustainable. Control maintenance costs (external repair, parts and internal labour), potential rental costs and maintain equipment rates at optimal levels to ensure OEB mandated ROE is achieved.

Costs:

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	29.1	31.8	32.1	32.4	32.6	158.0
Less Removals	-	-	-	-	-	-
Gross Investment Cost	29.1	31.8	32.1	32.4	32.6	158.0
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	29.1	31.8	32.1	32.4	32.6	158.0

**Includes Overhead at current rates.*

GP-02 Real Estate Field Facilities Capital

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	180.1
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Non-System Physical Plant		

Investment Need:

The Field Facilities Capital work program addresses the accommodation portfolio of administrative and service facilities in terms of improvements, building additions and new facilities as determined by Hydro One's operational requirements and asset condition. This program ensures that essential and supportive improvements are made to administration and service facilities to minimize building and site related risks to the operations; serve operational requirements; and promote efficiencies in the maintenance and operation of the facilities in the longer term.

Capital investment is periodically required in order to continue to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. The investment need is driven by the following key factors:

- deteriorating facilities that are at or near the end of life;
- compliance with current regulatory requirements, such as Accessibility for Ontarians with Disabilities Act and the Ontario Building Code;
- expanding work programs;
- new accommodation needs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity.

More than 40% of administration and service facilities are estimated to be more than 40 years old. These facilities are largely undersized, ill configured and underperforming to current operational requirements with resulting increase to operating costs for maintenance and repair and inefficiency to facility and business operations.

The Field Facilities Capital work program focuses on undertaking facility work encompassing improvements, additions or new facilities. Work is undertaken on a priority and timely basis at a level of expenditure required to support the business operations to fully deliver the prescribed various work programs addressing network requirements, customer needs, corporate and government policy and regulatory/licensing directives in a safe, efficient and cost effective manner. This work is conducted on a project basis.

Alternative 1: Status Quo

This alternative is to effectively curtail future investment on a minimal basis in an attempt to operate within the outdated facilities.

This alternative is not sustainable. Without necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where efficiency and safety become impaired. Incidents arising from this alternative will hamper Hydro One's ability to perform its work and serve customers.

This alternative would require additional operating expense for maintenance repairs, which have not been factored into this Application. The risk created by this alternative, and the additional operating maintenance expense it would create, caused it to be rejected without further analysis.

Alternative 2: Update Facilities *(Recommended)*

This alternative would bring field facilities to an acceptable state of repair and make strategic additions or replacements where beneficial.

The spending requested herein is an estimate of the work to be performed over the planning period. The development of field facilities entails an on-going, comparative evaluation of alternatives, which entails the expansion and/or renovation of existing facilities, the lease or purchase of suitable facilities and greenfield developments against maintenance of the status quo condition. The ultimate investment will be dictated by the circumstances in place. The objective is to pursue the most cost effective strategy that addresses operational requirements and manages risk. Operational considerations are for both existing and future requirements; the latter considers changes to the business, e.g., volumes and delivery strategy. Regardless, each substantial investment will be subject to analysis and approval based on its benefit prior to implementation.

The prime consideration throughout is to extract the value of existing facilities through ongoing operations, maintenance and sustainment investments in line with operational requirements. Where facility and/or operational conditions/requirements dictate an examination of facility alternatives, the objective is to derive the greatest net assessable benefit to the company.

Investment Description:
The key program work activities include:

- replacement of major building system/components, including roof structures; windows and cladding; heating, ventilating and air conditioning (HVAC) systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at end of life;
- site replacements and additions, including drainage; asphalt, fencing; and septic/well (servicing); and
- addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements.

The required capital investment for field facilities is outlined in the Costs section below. These amounts are needed to fund required improvements of existing facilities and the development of new accommodation solutions through renovation and/or expansion and the acquisition or development of new facilities as required by the company's work programs. Projects can be multi-year; and the work is contingent in several projects on the successful identification and acquisition of development sites and in all instances obtaining the requisite municipal planning approvals. Furthermore, certain projects are tied to the successful and timely completion of utility acquisitions or others may be adjusted for emerging acquisition opportunities.

The current estimate of the volume of work to be completed annually at individual sites/facilities is as follows:

Work	**Annual Completed Projects**
New Facilities and Major Renovations	2 – 4
Site Improvements (asphalt; drainage; servicing; fencing; security)	20 – 25
Building Envelope (roof; windows/doors; cladding)	20 – 30
Mechanical & Electrical (HVAC; lighting; generators)	15 – 20
Minor Building Renovations and Additions	10 – 15

Benefit is realized through a number of factors, such as lower cost, improved operational performance, regulatory compliance, enhanced health & safety, reduced risk, enriched life cycle management and adaptability to address known or anticipated change.

Risk Mitigation:

Cost certainty for new operating centres is established through the use of a scalable template design and experience from recently completed projects. Developments are completed in accordance to prevailing commercial standards and practices.

Developments of new facilities are in various instances dependent on the availability of suitable sites and requisite municipal approvals, which is managed through advance planning and acquisition. Development interests are cultivated by leveraging municipal officials/departments and utilizing the services of the real estate and development community.

Facilities redundancy and low value investments are managed by conducting regular reviews with the various lines of business to understand and align with current and emerging work programs and identify common requirements and workplace synergies. Furthermore, planning is integrated with utility acquisition strategies and objectives to identify opportunities, create flexibility and manage facilities investments.

Result:

- Field Facilities that serve current operating requirements of the various lines of business.
- Field Facilities commitments and investments aligned with known and emerging operating requirements and corporate business decisions.
- Maintenance of existing Field Facilities through timely replacement of major building systems/components.
- Enhanced health & safety of employees operating within Field Facilities.

Outcome Summary:

Customer Focus	• Improve the ability of the lines of business to address customer needs through facilities that commensurately align with operational requirements.
Operational Effectiveness	• Maintain and improve operational effectiveness of the lines of business through timely and strategic facilities investments.
Public Policy Responsiveness	• Comply with government policy and regulatory/licensing directives.
Financial Performance	• Cost savings realized through the broad consideration of facilities alternatives. • Cost effectiveness realized through regular assessment and timely investment. • Cost efficiency realized through facilities investments that align with current and emergent operating requirements and business decisions.

Costs:

The forecast costs are based on investment needs that are prioritized by blending condition assessments of Facilities' assets with cost estimates for sustainment capital based on vendor estimates and historic costs for similar projects. The anticipated spend identified in the table below, is based on Facilities depth of experience in accommodation planning that involve major work initiatives such as addition/renovation of existing facilities and acquisition or development of new facilities.

The cost for the development and/or renovation of facilities is controlled where applicable through template design, consistency of application, and the adoption of commercial building standards and practices.

The development of facilities and resulting final cost of a project are influenced by various factors beyond the typical realm of design, such as market, regulatory and site conditions/factors. Regulatory and site conditions are somewhat predictable through assessment, but not overly influenced by design considerations. Whereas, the market is highly influential to final cost for availability of suitable sites, market opportunity and interest and competing demand. These market factors could have a significant negative or positive influence to the cost of the project. Furthermore, existing facility conditions, site and/or building, may have significant latent defects that, irrespective of early assessments, are undetectable until implementation and could contribute to significantly higher costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	33.5	43.0	36.8	35.1	31.8	180.1
Less Removals						
Gross Investment Cost	33.5	43.0	36.8	35.1	31.8	180.1
Less Capital Contributions						
Net Investment Cost	33.5	43.0	36.8	35.1	31.8	180.1

**Includes Overhead at current rates.*

GP-03 MFA Servers and Storage

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	8.2
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. Hydro One's Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping the business running effectively. This investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time.

Key systems and the data generated must always be available (99.5%) to customers and employees involved with the delivery of customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities. As more customers are integrated into the SAP landscape and generate more business analytics the need for SAP capability increases. Move-to-Mobile and Customer High Bill Alerts are projects that require new hardware. Merger and Acquisition activity is another component that drives an increase to our server landscape.

Enterprise applications being refreshed (to stay within vendor supported levels) drive refresh of the overall environment. Hardware refresh is also required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Without refreshed assets, Hydro One would have difficulty enforcing performance agreements with vendors and could potentially be exposed to large, un-warranted costs. Conversely, refreshing as per vendor requirements allows for sustainment costs due to technology improvements being implemented as part of new deployments to be favourably re-negotiated.

HONI continues to increase its virtualization footprint for any new/existing applications that are refreshed. With virtualization, several operating systems can be run in parallel on a single server. This parallelism and allows Hydro One to better manage updates and changes to the operating system and applications without disrupting the user. Virtualization can improve the efficiency and availability of resources and applications in an organization.

Hydro One continues to explore opportunities to leverage cloud based application/infrastructure services while complying with HONI's corporate data security policies around NERC, CCAI, and PIPEDA.

IT system availability directly impacts the productivity of employees who use the technology. IT availability also has direct impacts on the availability and security of the power network itself given the modern suite of tools that are relied upon to monitor and operate the grid.

Alternative 1: Delay Refresh

This alternative would seek to delay the replacement of equipment past its current life-cycle expectancy.

Not refreshing end-of-life servers or delaying investment in storage devices beyond the current level will impact the reliability of IT systems and increase the incidents of failure. This reduced reliability will impact application uptime and overall system availability for customers and internal users alike. It will also drive additional sustainment costs, as many vendors commonly charge their services at a premium rate to support end of life products. It will remove the ability to build out capacity on-demand capability and will cause hardware to be added frequently and incrementally. This "just-in-time" server add strategy comes at a significant premium due to the lack of bulk buys, multiple complex setup and staging processes and potentially costly delays to important Business IT projects if hardware procurement has any issues.

Alternative 2: Refresh In-line with Life Cycle Guidelines (Recommended)

This alternative would keep assets current and refreshed. This option will support the maintenance of up-time requirements and ensure that data and processing ability is available to customer and employees.

Investment Description:

Wintel servers are refreshed on a three- to five-year cycle and UNIX servers are refreshed on a five- to seven-year cycle. These cycles fall within industry best practices and maintain warranties within an acceptable level. Virtualization technology is being leveraged to further increase the life of our physical servers. The replacement cycle for refresh of Wintel and Unix servers is to maintain vendor-supported levels and includes hardware upgrades, capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing.

In determining when systems require replacement, the functionality, operating and maintenance (i.e., standard warranty or extended warranty) costs are assessed. The funding for the servers and storage refresh/replacement program varies year over year depending on hardware lifecycles and business requirements for increased processing capacity.

Costs in 2018 to 2022 reflect typical lifecycle refresh of end of life storage hardware.

Risk Mitigation:

Replacement of infrastructure as proposed in this investment is a fairly routine occurrence that has been performed many times within the Hydro One environment by the staff that will be involved in this project. While issues occur, the risk of project failure is very low and most adverse situations can be anticipated and addressed from experience.

Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome. In the event of hardware failure, defects discovered, or resource constraints the project will work the systems integrator equipment manufactures to resolve issues or modify scope timelines until the issue can be resolved or architected.

Result:

A proactive investment approach reduces the risk of prolonged IT system outages and reduces the costs of unplanned investment for problem resolution. It also reduces the risk to

Hydro One's ability to respond to business requirements and project delivery due to IT system integration and scalability impacts.

Outcome Summary:

Customer Focus	• Support information availability to customers ensuring that systems are supported and reliable. • Improve customer satisfaction around ease of use and experience of our customers when accessing billing information on e-customer.
Operational Effectiveness	• Increase productivity by ensuring that applications / systems function as designed and provide Hydro One employees with the information they require to perform their daily work effectively.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost by minimizing the potential for costly outages and unplanned refreshes or upgrades. • Maintain vendor support and the ability to enforce performance or availability SLA's thus avoiding increased costs.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs. The market for these products has matured significantly over the last decade. Major cost fluctuations are not anticipated and, in any event, are foreseeable and addressable through sound procurement strategy.

Funding decrease re-directed to ISD-GP-05.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.7	1.7	1.6	1.6	1.6	8.2
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	1.7	1.7	1.6	1.6	1.6	8.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**8.2**

**Includes Overhead at current rates.*

GP-04 Minor Fixed Assets - Desktop, Laptop, Printer

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	4.8
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System (GIS). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. Minor Fixed Assets ("MFA") are the method by which the information and capability of these enterprise systems are provided to employees. Currency and functionality of the MFA fleet is critical to allowing employees perform their work productively.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of customer service programs and Distribution work management programs linked to H1 Customer satisfaction goals/KPIs – Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

MFA equipment includes:

- Desktops, Laptops, and Printers used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications;
- Tablets used with, among other things, Geospatial Information Systems ("GIS") applications for undertaking system design work and for asset condition assessments;
- Rugged Tablets and mobile devices used by field staff for entry of work related data; and
- Plotters commonly used by Hydro One engineering and operations staff for design work and to plot system maps.

Replacement of MFA that have reached the end of their useful life is necessary to address warranty considerations and to maintain hardware reliability, as well as to upgrade existing equipment to meet business performance needs.

Equipment refresh maintains or reduces maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty.

Alternative 1: Delay Hardware Refresh

This alternative would delay the refresh of assets and address increased failure and performance of the obsolete assets.

A delay in hardware refresh would affect operational effectiveness and our ability to serve customers. Aging hardware impacts application performance which in turn impacts ability to provide timely responses to customers in a call centre environment. In other areas of the business aging PC's perform poorly as new state of the art applications are deployed demanding more processing power and memory.

Delaying the equipment replacement or reducing funding beyond the current level will negatively impact the ability of employees to support the business and customers due to the increased risk of breakdown and lost productivity.

Other investment changes intended to reduce replacement would increase sustainment costs and the time to restore IT services. This is because technology beyond the vendor-supported life is normally outside of service agreements, and parts and labour are difficult and costly to secure.

Alternative 2: Refresh Per Plan (Recommended)

This alternative would strive to purchase and refresh MFA within asset life cycle guidelines.

New models are selected as part of technology refresh to meet user needs based on business requirements (USB Ports, Processing & Memory requirements, indoor versus outdoor usage, etc). Newer models provide additional compatibility with new business applications, operating systems, modern browsers, etc. The hardware refresh allows Hydro One to enforce service levels and performance based SLAs with vendors.

The option of renting/leasing MFA was reviewed. However, most of this equipment is made up of small, relatively inexpensive items whose usefulness is generally exhausted by end of life. Therefore it was deemed not feasible to rent or lease these items on a long term basis since leasing vendor margins would be purely accretive to the cost and would be higher than any cost of capital benefits from leasing. As a result, this alternative was not pursued.

Old equipment that is past the end of its useful life becomes unreliable and negatively impacts the ability of the business to perform their day to day work, thereby increasing costs to Hydro One and its customers. In addition, existing equipment may need to be upgraded to meet the changing needs and applications of the business.

Investment Description:

Hydro One’s practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. Historically, Hydro One’s refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

The estimated units to be replaced over the program are as follows:

	2018	2019	2020	2021	2022
Desktop/Laptop	1050	950	950	950	950
Printers	50	47	47	47	47
Other	21	19	19	19	19

Risk Mitigation:

Refresh programs run year over year, assets not deployed in one year are leveraged first the next year. Total number of machines deployed over 3-5 years remains constant.

Issues around software compatibility are addressed as part of certification process where a standard locked down image is deployed to all users with packaged/certified software applications.

Issues around hardware failure are addressed via the warranty process with the vendor.

Result:

The PC and Printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems, promoting workforce productivity.

Outcome Summary:

Customer Focus	• Support customer services by ensuring employees have the necessary equipment to meet customer needs.
Operational Effectiveness	• Maintain productivity by ensuring reliability of IT tools required by Hydro One employees to perform their daily work.
Public Policy Responsiveness	
Financial Performance	• Overall costs are minimized by enabling general employee productivity.

Costs:

Estimates are driven by historical costs, which are driven by the inherent lifecycle of the devices.

Funding decrease re-directed to ISD-GP-05.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.9	1.0	1.0	1.0	0.9	4.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	0.9	1.0	1.0	1.0	0.9	4.8
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.9**	**1.0**	**1.0**	**1.0**	**0.9**	**4.8**

**Includes Overhead at current rates.*

GP-05 Hardware/Software Refresh and Maintenance

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	37.8
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for the field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of our customer service programs and work management programs linked to Hydro One customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

Investments are needed to build contingency so as to ensure that critical systems are available and can survive the failure (result of a manufacturer bug, security patch, etc) of any single supporting technology component. Investments in supporting technology components include telecom, IT hardware and software. Leveraging these investments with effective vendor maintenance means that the assets can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Alternative 1: Delay Refresh

This alternative would defer replacement of assets due for refresh and address additional issues with higher failure rates of the systems.

Increasing the current life-cycle asset refresh strategy takes Hydro One beyond industry practice and significantly increases risk to the business in the following areas:

- Increases in employee dissatisfaction and decreased productivity due to frequent and/or prolonged service outages;
- Degraded regulatory relationship from disruptions to market operations of IT systems that interact with market participants;
- Decrease in customer satisfaction due to failure of enterprise wide applications such as SAP, ihub/Tivoli, Microsoft Exchange, mobile applications, customer billing, relationship management, and call centre systems; to meet service quality index for customer service; and
- Productivity declines due to the high unit cost of supporting and servicing applications without vendor support.

Alternative 2: Refresh Per Plan (Recommended)

This would replace servers within life cycle guidlelines. A number of factors drive the refresh of an application. Hardware or Applications out of vendor support is one component, while additional application functionality or performance considerations will also drive a refresh. This investment covers the cost to build the new servers along with any data migration activities and decommissioning.

Server hardware is refreshed every 3-7 years based on hardware type. Hardware refresh is required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Refreshing per plan allows for sustainment costs to be favourably negotiated due to technology improvements being implemented as part of new deployments.

This investment covers the capital costs, including Professional Services, to build new Web/Database/Application and Infrastructure servers along with all relevant data migration, Operating System, hardening, and decommissioning activities. There are a number of factors that drive hardware refresh – vendor supportability being a primary driver. There are other important considerations as well, including hardware age, and the general availability of supported replacement parts.

From an application perspective, today's business demands performance levels that are only offered by the latest server hardware and network technologies. While from a technology perspective, the entire IT market continues to virtualize and optimize key areas that are common across all data-centres – virtualizing server compute, storage and network. Refreshing this aging hardware allows for greater scalability and higher server densities, since it is possible to run addititional virtual servers with a smaller hardware footprint.

Investment Description:

Included in 2018 to 2022 the planned investments relate to the implementation of enterprise resource planning ("ERP") applications and related tools including SAP, further IT security access control and monitoring capabilities, middleware and databases, productivity tools, and server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms. Refreshes for applications in sustainment are funded from this investment. The only exception is if the refresh is going to drive new functionality that can be tied to a Business Case. Lastly, a system being refreshed in order to accommodate its inclusion into the Disaster Recovery Program (DRP) would also be funded by this investment.

Risk Mitigation:

No concerns are foreseen with completing the completing the Hardware/Software refresh program. Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome.

Any risks around resourcing (specific skillset) will be addressed prior to project award with systems integrators. The award will ensure proper expertise is maintained during the life of the project and is well documented as part of scope execution.

Result:

This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments for problem resolution. This investment in IT system reliability enables general employee productivity because users have access to the tools they require to work, and it enables customer satisfaction through availability of enterprise wide applications, customer call centre and outage management systems.

Witness: Lincoln Frost-Hunt

Outcome Summary:

Customer Focus	• Ensure IT Hardware / Software is supported and reliable to prevent information gaps for customers. Performance and Stability of IT Hardware / Software directly impact ability to service customers in a timely manner (ie: Outages, Billing Inquiry, Program Enrollment, etc).
Operational Effectiveness	• Maintain the reliability of IT Hardware/Software to allow applications / systems to function as designed and provide Hydro One employees with the information they require to perform their daily work.
Public Policy Responsiveness	• Maintain efficacy of the of IT systems that interact with market participants and support the IESO in its market oversight mandate.
Financial Performance	• Overall costs are minimized serves to reduce the potential for costly outages and unplanned refreshes or upgrades.

Costs:

Estimates are driven by historical costs, which are driven by the inherent lifecycle of the devices.

Funding increase offset by decrease within ISD-GP-03, ISD-GP-04 and ISD-GP-06.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	8.0	7.6	7.5	7.4	7.3	37.8
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	8.0	7.6	7.5	7.4	7.3	37.8
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**8.0**	**7.6**	**7.5**	**7.4**	**7.3**	**37.8**

**Includes Overhead at current rates.*

GP-06 MFA Telecom Infrastructure

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	2.5
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through the call centre. The Enterprise systems also provide the backbone of Hydro One's business operations within finance, human resources, supply chain as well as asset and work management for its field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Company's Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to Hydro One's customers and employees involved with the delivery of the Company's customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

This investment is required to replace end-of-life assets and to maintain service reliability and security, by refreshing network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source system, and upgrading the security solutions for external network interfaces.

Telecom infrastructure is the underlying hardware to support the business telecom network which is used to transmit data required to run business applications. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Alternative 1: Delay Refresh

This alterative would defer purchase of Minor Fixed Assets ("MFA") and deal with the incremental sustainment issues arising as a result.

Delaying the equipment replacement or reducing funding beyond current level will increase time between hardware refreshes, which may cause degraded voice and data network, reduced capacity to accommodate Move, Adds or Changes activities and poor network performance. Network availability and performance directly impacts customer interaction (ability to respond to customers in a timely manner in a call centre settings) and Lines of Business efficiency (performance from remote field sites will impact end user efficiency on applications as a result of poor network connectivity).

Alternative 2: Refresh Per Plan (Recommended)

This alterative would purchase and refresh equipment purchases according to their life cycle requirements.

Today's business applications demand the higher performance offered by current server and network technologies. The integration of systems, their applications, and sharing and dissemination of underlying data also drive higher complexities in order to fulfill expected business objectives and outcomes. In conjunction with this, from a raw hardware perspective, performance requirements also increase as more and more virtual servers are stacked onto fewer and fewer physical assets. Physical network bandwidth requirements increase proportionately in all these respects. Additionally, today's networking devices offer more mature degrees of network virtualization, and enable network segmentation and micro-segmentation which fulfills security requirements by further securing the data-centre environments.

Refreshing per plan allows HONI to deploy current generation technology in order to meet and exceed the demands put upon the underlying network technologies. For example, Move 2 Mobile project will rely on increased bandwidth from remote sites to ensure work being done is updated in SAP as quickly/timely as possible so the Company can reassign crews to other jobs if they are finished early. As Hydro One introduces new applications into its eco system, the aggregate need for more bandwidth increases. Current network technologies also allow for new functionality to be explored to further optimize network traffic making packet transmission more efficient and helping the prioritization of network traffic.

Investment Description:

The investment in Networks for voice and data is undertaken to replace end-of-life assets and to maintain service supportability, network reliability and network security. The strategy is to replace equipment that is no longer vendor supported. For network equipment, the refresh occurs about every five years for voice and data network related hardware. The funding for voice and data networks varies year to year depending upon hardware lifecycle refreshes, and incrementally as increasing business demands necessitate increased network bandwidth. As more business work flows are introduced and automated, there is generally always an impact to the underlying network. In other cases, additional workloads are pushed to remote field offices, which sometimes require a more efficient network infrastructure. In general terms, as business functionality increases and demand grows at a given Hydro One location (for example, Business Admin Support center (BASC) or an Operations (OPS) centre), network bandwidth is taken into consideration and if warranted, is incrementally increased to support the business. Costs in 2018 to 2022 reflect normalized refresh program covering Voice Networks, Telecom Networks, Data Centers and Perimeter Security.

Risk Mitigation:

All MFA assets are purchased in a just in time approach and in serviced in the same year of purchase. Any risk of assets not being installed will be managed as part of project scope with timelines being reflected in current or following year.

Result:

The Telecom Infrastructure refresh will provide a secure and reliable network to support core business applications, address Hydro One’s communication needs and maintain hardware supported levels required by our contractual commitments with vendors and outsourcing partners.

Outcome Summary:

Customer Focus	• Ensures reliable voice and data network to address Hydro One customer's communication needs to service customers.
Operational Effectiveness	• Maintain efficiency of the reliability of voice and data infrastructure to allow all IT applications to function as designed.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost to maintain its IT environment proactively and minimize the potential for costly outages and unplanned upgrades.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs.

Funding decrease re-directed to ISD-GP-05.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.6	0.5	0.5	0.5	0.5	2.5
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	0.6	0.5	0.5	0.5	0.5	2.5
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**2.5**

**Includes Overhead at current rates.*

GP-07 Corporate Performance Reporting

Start Date:	Q12019	**Priority:**	Low
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.8
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

The Corporate Performance Reporting ("CPR") application is required to produce key high-profile, corporate reporting deliverables (e.g. OEB mandated reliability reports, reports to government, customer reports, and industry benchmarking reports) including SAIDI and SAIFI.

The Business has been using a custom, third-party software tool built approximately 7 years ago. It is still being supported by an external vendor. This tool is not supported by Corporate IT processes and Service Agreements.

There are limited knowledgeable resources available. As a result, it continues to incur costs and present unacceptable business reliability and continuity risks, unavailability of IT sustainment processes/agreements, and potential lack of vendor resource stability. There is limited availability of design and functional documentation on the algorithms, data sources and process chains. For a successful migration, any upgrade project must document these algorithms. This makes modifications for new requirements and standards difficult and risky to implement.

With the information contained on a stand-alone, proprietary system, resources in the Performance Management department are typically needed to fulfill other Hydro One Lines of Business ("LOB") with ongoing data requests. These requests can be labour-intensive.

Alternative 1: Maintaining the Status Quo

Maintaining the status quo leads to continued high risk and dependency on a custom, third-party application. In a qualitative sense, tight dependency on the limited vendor resources and limited support for a non-commissioned environment are high Business Reliability and Continuity risks given the importance of the data. Status quo will also keep Performance Management resources engaged in supporting other LOB's versus responding to new OEB requests and focus on core tasks and new LDC reporting requirements.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 2: Migrate Existing Servers into Commissioned Environment

The option to migrate the application and data servers used for the current Performance Management tools into the sustainment (commissioned) environment was reviewed. This would place the support for the functioning of the servers and their interconnectivity with Inergi under the Enterprise umbrella for day-to-day operational support. This alternative was rejected because it would not materially reduce risks.

In a qualitative sense, the primary drivers of Business Reliability and Continuity risk are the diminishing availability of qualified resource pool for the existing tool combined with the lack of documentation about the applications. Neither of these would be reduced by this alternative.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 3 *(Recommended)*: Integration of CPR with SAP system

The plan is to transition the application and data to an enterprise supported platform (SAP). A Discovery phase was conducted to document the Business requirements and functional recommendations and to estimate costs and timelines for the delivery of this project.

The Quantitative and qualitative analyses of risk mitigation and benefits for the proposed project are summarized as follows:

1. Business Continuity Risk: The number of vendor expert staff who currently supports this program has shrunk down to two individuals. One of the benefits of integrating CPR into the SAP ERP tool is that internally trained FTE will support this program, further improving business continuity and lowering cost.
2. Commissioned System: CPR is a stand-alone application that is not integrated as a Hydro One enterprise application. Integrating CPR into SAP further improves its business continuity benefit.
3. System Documentation: Currently there is a lack of visibility of stored procedures (algorithms and logics) in the CPR program. Through this project, all such embedded algorithms and stored procedures will be documented and be more visible.

4. Optimization of Resources: Integration with enterprise SAP self-service tools results in avoidance of the current third-party vendor support (operational, maintenance and enhancement) costs.
5. Migration to an Enterprise Platform: will allow for a redistribution of Performance Management resources by allowing LOB's to access data directly from SAP. Performance Management Staff to join the "Planning" organization and engage in asset management and reliability related analyses particularly those focusing on new/evolving OEB and LDC reporting requirements.

Savings from the above are expected to be achieved beginning in 2021. These savings include a potential reduction in staff necessary to support the current program, avoided vendor enhancement work, and elimination of vendor annual support fees, which are currently $500k per year, (50% of which is attributable to Hydro One Distribution).

Investment Description:

This project is to build the new reliability reporting tools used by Regulatory / Performance Management teams. The project will involve the migration of the application and data servers and install new code into a sustainable SAP-BI solution to be used for the Performance Management functionality and rules. The project will also involve the migration of historic data, and leverage available SAP and enterprise tools including self service capabilities, reporting and other tools. In contrast to the current Oracle platform, SAP is a commissioned and fully supported environment.

The recommended execution plan will take approximately 18 months to complete both the distribution and transmission reliability components by the fourth quarter of 2020.

Risk Mitigation:

Business Requirements

There is no expectation of major gaps given the extent of the requirements and discovery workshops, however, it is possible and likely that new reporting requirements evolve and some details will require refining as the design and build steps move ahead. All issues will be addressed using standard SAP code. The plan will include provision for these and will address both time and cost implications.

Data Quality:

Early engagement and contact with the teams contributing to identifying data entities, data gathering, data conversion and data migration has to take place to monitor their progress and alignment to the CPR Delivery plan.

Solution Complexity:

The new tools will incorporate numerous, and in some cases complex calculations to derive the performance metrics. A concern is that the build may result in components of such complexity as to make testing and error detection difficult. The project team has to engage with the Vendor to build the new tools such that testing of each and isolation of the source of issues is readily possible. The plan will include provision for this and will address both time and cost implications.

Change Management

One of the goals for this project is to provide greater access outside of the Performance Management Team to reliability related data and scores via the enterprise self-service tools. Change Management is a key player to deliver the vision, training and job aids to the LOB's wishing to access this data.

Result:

Through the delivery of the Corporate Performance Reporting project, the following performance improvements would be achieved:

1. Stability and Optimization of Resource: The number of vendor expert full time employees who support this program has decreased from four to two individuals. One of the benefits of integrating CPR into SAP tool is that internally trained employees will support this program, further improving business continuity of this program. This will also optimize resource deployment in the Performance Management department.
2. Commissioned / Supported System: The current CPR tool is a stand-alone program that is not integrated as a Hydro One enterprise application and is not supported by Corporate IT processes and Service Agreements. Integrating CPR into SAP further improves its business continuity benefit.

3. Increased Visibility: The knowledge of stored procedures (algorithms and logics) in the CPR program resides with the third party. Through this proposed project, all such embedded algorithms and stored procedures will be documented and become visible.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Reduce continuity risk to the production of corporate performance metrics. • Improved efficiency and resource deployment by focusing on evolving reporting requirements.
Public Policy Responsiveness	• The outputs from the CPR system are frequently used for regulatory agency reporting (OEB & NERC & IESO & NEB), government agency reporting (Min of Energy), customer queries, and industry associations (CEA & NATF).
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the following application components and processes: Data Collection, Data Cleansing, Calculations, Reporting and Visualization.

The estimated cost was derived from the CPR Discovery work, in which Inergi was engaged to provide an estimate for the delivery work. At this time the estimate itself is high quality, however, it will be validated prior to submission of the business case to account for the time lapse between Discovery and Delivery phases (~ 4 years). Given the 10+ weeks of workshops to review the requirements; the gap is expected to be small and manageable.

Investment was deferred to give priority to ISD-GP-35.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	0.0	1.9	0.9			2.8	3.7
Less Removals						0.0	0.0
Gross Investment Cost	0.0	1.9	0.9			2.8	3.7
Less Capital Contributions	0.0	0.0				0.0	0.0
Net Investment Cost	**0.0**	**1.9**	**0.9**			**2.8**	**3.7**

**Dx components only and includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-08 PCMIS Modernization and Optimization

Start Date:	Q1 2020	**Priority:**	Low
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	1.3
Primary Trigger:	Cyber Security		
Secondary Trigger:	Reliability		

Investment Need:

The Protection and Control Management Information System ("PCMIS") tool is a critical platform used to support the Company's power system operations and ensure compliance with reliability and cyber security regulations. PCMIS is the single system of record for all Protection and Control ("P&C") device settings. PCMIS is utilized by Hydro One engineering, operations, and field personnel, as well as technical personnel in Local Distribution Companies across Ontario. The tool contains 'Bulk Electric System Cyber System Information' ("BESCSI"), sensitive data that must be strictly controlled and protected in accordance with Critical Infrastructure Protection regulations, as mandated by the North American Electric Reliability Corporation.

The primary function of PCMIS is to maintain device settings for the Intelligent Electronic Devices ("IED") that protect and control the grid. Over the years, PCMIS has been modified to meet various business and regulatory requirements, and has become a highly customized tool. The application and associated infrastructure are approaching end-of-life (EOL) and need to be replaced.

PCMIS is a key Hydro One enterprise system that the company depends on to operate the Ontario electrical grid. In 2013, Accenture assessed the PCMIS platform and prepared a detailed report. The report highlighted numerous gaps in existing processes and significant deficiencies in the technology. System scalability, sustainability, and data integrity were all rated 'Poor'.

Alternative 1: Maintain the "Status Quo"

This option would have us leave the legacy system as is. However, maintaining the status quo and running an important application on unsupported infrastructure, exposes the company to the following risks:

- Inability to operate, repair, and replace critical P&C equipment;

- Failure to comply with cyber security regulatory requirements; and
- Failure to comply with reliability regulatory requirements.

Alternative 2: System Redesign and Replacement. (Recommended)

The planned changes will provide an opportunity to replace servers, operating systems, and databases with up to date technology to ensure operational and support longevity of the platform.

A modern PCMIS platform will be built on new infrastructure with secure, robust technology offering high availability (HA) and disaster recovery (DR). The PCMIS application will be replaced with fully supported commercial software. Functionality and integration interfaces will be optimized, consolidated with other Hydro One enterprise platforms or eliminated.

This is the preferred alternative, as this option will provide a modern robust system that will meet regulatory requirements. The company would like to address the project at the first possible opportunity, which based on available funding is expected to be in 2020.

Investment Description:

The project will maintain and further strengthen PCMIS as the single source of record for all P&C device settings. PCMIS supports users across the enterprise as well as engineering and field personnel in external utilities, providing centralized, controlled access to cyber-sensitive data. The system ensures that the configuration of critical grid protection systems is accurate and manages approval of any settings changes, supporting numerous key business processes including planning, construction, maintenance, repair, network operating and outage management. PCMIS data is used by the Distribution Management System (“DMS”) to support advanced power system application analytics.

The PCMIS platform is aging and replacements are required to the entire infrastructure. This investment focuses on delivering a modern technological stable solution to address gaps in existing process and deficiencies in technology as highlighted in a recent third-party assessment. Processes will be optimized. Proven, secure technology will be implemented, resulting in a system that will provide years of efficient and reliable service.

The scope of this investment is to:

Replace existing PCMIS software and infrastructure;

Develop detailed system requirements and performance criteria. Design new infrastructure with proper development, quality assurance (QA), and DR environments. Build, setup, secure, configure, and test new infrastructure and integrate with secure, encrypted communication links. Assess available commercial software and select optimal solution. Purchase, install, configure, and test new Process and Control Settings software.

Introduce process improvements and efficiencies;

Conduct comprehensive assessment of current processes. Working with the business groups we will optimize processes and leverage opportunities for consolidation with other Hydro One enterprise systems. Rationalize and eliminate customizations where possible.

Migrate data and launch new system.

Develop, test, and execute detailed data migration plan; provide orientation and training following proven change management principles; establish effective sustainment contracts.

Risk Mitigation:

To mitigate risk associated to the implementation of a new system and the time required to provide access and train all the LDC's, the new and old systems will be run in parallel for a short period of time.

To mitigate risk associated with change resistance, the project will employ a full organizational change strategy. This will include the stakeholder management at the earliest stages, performing a change impact assessment and following resistance management plans will help secure buy-in from the user community.

Result:

The anticipated outcomes of this investment include:

- a fully supported platform,
- improved system redundancy and high availability, and
- optimized operational processes.

Outcome Summary:

Customer Focus	• Provide secure and reliable access to the protection and control information that will allow efficient system access support and maintenance.
Operational Effectiveness	• Ensure improved system availability. • Reduce system downtime and facilitate maintenance and upgrade work. • Improve access to critical configuration information allowing Hydro One and LDC's to be more responsive to operational issues.

Costs:

Cost estimates are based on historical costs of similar projects of this type.

Investment was deferred to give priority to ISD-GP-13.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets		0.0	1.3			1.3
Less Removals						
Gross Investment Cost		0.0	1.3			1.3
Less Capital Contributions						
Net Investment Cost		**0.0**	**1.3**			**1.3**

**Includes Overhead at current rates.*

GP-09 ECM Phase C

Start Date:	Q1 2018	Priority:	Low
In-Service Date:	Q4 2020	Plan Period Cost ($M):	3.0
Primary Trigger:	Public Policy Responsiveness		
Secondary Trigger:	Privacy		

Investment Need:

Enterprise Content Management ("ECM") is the technology used to capture, manage, store, preserve, and deliver content and documents related to organizational processes. ECM tools and strategies allow the management of an organization's unstructured information, wherever that information exists. Documents are centralized, searchable and retained or disposed as per requirements of regulatory bodies.

Hydro One is obligated to meet the requirements of many different regulatory bodies and programs with respect to document management. These include the North American Electric Reliability Corporation ("NERC") / Critical Infrastructure Program ("CIP"), the Ontario Energy Board, the Ontario Securities Commission ("OSC") and many others. Failure to meet these requirements will result in undue legal and regulatory risk for Hydro One.

Hydro One has commenced an Enterprise Content Management ("ECM") initiative comprised of three Phases.

- Phase A represents the classification of a majority of non-complex unstructured data. This was completed March 2015.
- Phase B (started November 25th, 2016 and is currently in progress) will develop several Proofs-Of-Concept (POC) offering options and alternatives for the implementation of records schedules (POC-1), email management (POC-2), management of physical documents (POC-3) and Records Management reporting (POC-4). Upon completion of Phase B, the proofs-of-concept will be configured for immediate implementation.
- Phase C will implement the POC across the company including records schedules, email management, management of physical documents and Records Management reporting (The purpose of this request is to seek funding to implement Phase C).

Alternative 1: Status Quo - Do Not implement Records Schedules POC

This alternative would not proceed with implementation of the Phase C Proofs of Concept and effectively defer the project indefinitely.

Maintaining the status quo is “high” risk because there are currently no records schedules (retention dates, disposition dates) activated on any Hydro One company record (emails and physical documents).

If the status quo were to be maintained, Records Schedules (retention dates, disposition/destruction dates) would not be affixed to physical documents or emails (company records). Without a “trigger” to demonstrate the requirement to retain company records or dispose of company records, Hydro One may be unwittingly storing company records that should be destroyed or inadvertently destroying company records that should be retained.

Alternative 2: Implementation of POC – 1 only

This alternative proposes the implementation of POC-1 only (records schedules POC only).

This strategy would not reduce the risk to Hydro One as the value of records schedules is in its application to company records. Records schedules need to be applied to company records as this POC cannot reduce company risk as a stand-alone product. The value of this POC is derived from its application to company records. As such, this alternative was eliminated.

Alternative 3: Full Implementation of Phase C (Recommended)

The recommended alternative is to proceed with the 3rd Phase of the ECM project - full implementation of all POCs including the implementation of records schedules, POC-1 (data retention dates, disposition activation, etc.) email management (POC-2) and physical document management (POC-3) and records management reporting and administration (POC-4) after the completion of Phase B. reporting and administration.

Investment Description:

ECM Phase C will result in the activation of records schedules including the retention, and destruction dates applied to the physical and email documents. In addition, dashboards demonstrating the growth in SharePoint usage and Open Text publishing (archiving) would allow Hydro One to monitor user adoption.

Risk Mitigation:

As ECM Phase C is the implementation of proofs-of-concepts developed in Phase B, there is a "risk" associated with the scalability of each proof-of-concept. Full implementation is the preferred alternative. However, there is risk associated with the cost to implement several solutions enterprise-wide. To mitigate this risk, the "actual" cost of implementation of POC-1 (data retention dates, disposition activation, etc.) will be reviewed and a "go-no-go" decision will be taken to determine if any or all addition POCs should be implemented.

Result:

Records Management ensures that institutional records of vital historical, fiscal, and legal value are identified and preserved and that regulatory mandated records are discarded in a timely manner according to established guidelines and identified legislation.

Benefits of Records Management include:

- More effective management, access and discovery of current records (both paper and electronic) and related enterprise content;
- Increased institutional accountability and timely access to information; and
- Greater adherence to regulatory requirements.

Outcome Summary:

Customer Focus	• Ensures the privacy, integrity of records and the security of record keeping processes.
Operational Effectiveness	
Public Policy Responsiveness	• Compliance with policy guidelines set by NERC/CIP and OEB.
Financial Performance	

Costs

Investment has been accelerated due to business priority.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.0	1.0	1.0	0.0	0.0	3.0	4.3
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	1.0	1.0	1.0	0.0	0.0	3.0	4.3
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**1.0**	**1.0**	**1.0**	**0.0**	**0.0**	**3.0**	**4.3**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-10 Work Management & Mobility

Start Date:	Q2 2018	**Priority:**	High
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	6.7
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

The existing processes and applications used to manage work within the Provincial Lines, Stations, Forestry and some central organizations involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

All work and information needs to be scheduled, dispatched, executed and reported through a standard set of processes and technologies across all of these lines of business within Hydro One. For example, the existing applications used by the Provincial Lines organization to schedule, dispatch and report work lacks the functionality and integration to support the productivity gains that are possible.

The "Move to Mobile" project to implement work management and mobility improvements for the provincial lines organization is presently underway. This was described in the investment summary document IT-05 ("Field Workforce Optimization and Mobile IT"), which was provided in Exhibit D2-2-3 filed in support of Hydro One Distribution's revenue requirement application (EB-2013-0416).

Alternative 1: Status Quo

This alternative was considered and rejected as a result of the following:

- significant, achievable productivity gains would not be realized;
- would continue to rely on manual and untimely paper processes for recording work accomplishments;
- data entry would remain labour intensive, and errors and poor data quality would continue to be prevalent resulting in multiple visits to the same customer site;
- dispatchers would not be able to leverage geospatial capability related to the location of assets, crews and work in order to achieve more work in any given day; and
- the existing mobile platform would remain inconsistent with SAP's future direction.

Alternative 2: Introduce Mobility across All Lines of Business in a Single Initiative

The development and implementation of a company-wide solution incorporating all LOBs and workflows was considered. The complexity of analyzing each component of the planning, scheduling, dispatching, work execution, closeout and reporting processes for key business scenarios for all LOBs within a single initiative would require a multi-year effort and a significant level of risk. It would also introduce a very large company-wide Change Management component related to business processes and applications impacting thousands of employees. This alternative was rejected due to its size, complexity, risk and timing.

Alternative 3: Move to Mobile Implementation Projects at Individual Lines of Business (Recommended)

This alternative involves the implementation of mobile technologies and related business process changes within the Forestry, Stations and Corporate LOBs in a number of discrete, focused projects over the next few years. Each of these projects contains elements of process change, coupled with enabling technology which will result in productivity improvements being realized as the process changes are phased in across each line of business.

Building on the experience gained in the Provincial Lines Move to Mobile Project and from other utilities, particular attention will be paid to the change management strategy. The expected benefits are highly dependent on the field workers wanting to use, and continue to use the new processes and technology over time.

This alternative will result in both quantitative benefits similar to those expected from the Provincial Lines project, and qualitative benefits within Customer Care.

Investment Description:

Through a competitive procurement process in 2014, the decision to standardize using SAP's mobile capabilities was made and a systems integrator was retained to help configure and deploy the solution across the Provincial Lines organization. The systems integrator is currently designing the improved business processes to be consistent with the industry best practices they have experienced working with other clients. A commitment to achieve at least a five percent productivity gain was established, with a projected return on investment of 21.3% and projected ongoing annual savings of $12 million. This project is currently under way with an in-service date in the first quarter of 2017.

Subsequent projects for Stations, Forestry and Corporate LOBs are expected to mobilize during 2017 and 2018, using the standard business and technical solutions established during the Provincial Lines project.

This investment will streamline Hydro One work management processes and deliver an enhanced, integrated scheduling, dispatching and mobile solution for the three lines of business, achieving significant productivity benefits in each.

The projects for Provincial Lines, Stations, Forestry and the Corporate LOBs involve implementing the following:

- SAP's mobile technology for use by Hydro One's field workforce;
- new/upgraded planning & scheduling software, integrated with SAP and the SAP mobile capability;
- SAP mobile platform integration with Hydro One's geographical information system (GIS); and
- Standardized processes for work planning, scheduling, dispatch, execution and reporting, as well as for company-wide processes such as purchase requisition and invoice approvals, timesheet preparation and submission, expense management, and workplace safety inspection form preparation and submission. This includes the monitoring and reporting of the expected benefits, and if these benefits are not being fully realized, initiating remedial action to help ensure the expected benefits are realized.

Risk Mitigation:

The major risks for these projects are similar to the ones faced by the current Provincial Lines "Move to Mobile" project. For example, field workforce acceptance of the new processes and technical solution; system performance of the technical solution; the post go-live approach to supporting the changes all have risks that must be managed. Experience gained during the Provincial Lines project is a major risk mitigation element for the follow-on projects. Any combination of these risks could result in a project in-servicing delay however the same approach used in the "Move to Mobile" project will be applied in these projects. They will be led and owned by the line of business, solid project governance, similar to that being practiced in the current Provincial Lines project will be applied to these follow-on projects. The projects will also take into account the relevant lessons-learned from Provincial Lines.

Following Project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The projects will be led by a field operations VP who is familiar with the culture and challenges associated with a process improvement implementation of this scale with the field work force.

Result:

These projects will provide the schedulers and field staff with real-time or near real-time work status update capability, present staff with a consolidated view of work information, provide a geographic scheduling tool on mobile devices, and enable timely, quality data capture at source.

These projects will also provide a near paperless and automated work environment which will help save paper and fuel, reduce vehicle emissions as well as save corporate operation expenses. Reducing manual steps and providing data validation at time of entry, will result in higher data quality and increased staff productivity.

In addition to a minimum five percent productivity gain for the Forestry, Stations and Corporate LOBs, there are also qualitative benefits in the areas of employee safety, customer service and employee engagement.

Outcome Summary:

Customer Focus	• Improved information reliability for customers with validation of data at source of input. • Improved service levels for customer-related processes like new-connects.
Operational Effectiveness	• Improve work processes by eliminating / automating as much of the manual & paper handling work activities as possible. • Increase efficiency by employing better scheduling and more efficient status of work accomplishment. Forestry, Stations and Corporate LOB should expect to see productivity gains of at least 5%.
Public Policy Responsiveness	
Financial Performance	• Reduce one-time costs including the mobility, planning & scheduling software.

Costs:

The following costs are based on previous experience with the first Work Management and Mobility project for the Provincial Lines organization which started in 2015 and which is planning go-live during Q1 2017.

Investment funding decreased to reflect an updated approach to support Hydro One LOB business requirements.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.4	5.3	0.0	0.0	0.0	6.7
Less Removals						
Gross Investment Cost	1.4	5.3	0.0	0.0	0.0	6.7
Less Capital Contributions						
Net Investment Cost	**1.4**	**5.3**	**0.0**	**0.0**	**0.0**	**6.7**

**Includes overhead at current rates.*

GP-11 Enterprise Geographical Information System

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	5.8
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

Geospatial technology is a key information technology (I/T) infrastructure component that improves the effectiveness and efficiency of a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. While the technology is common to both distribution and transmission functionality, the investments and costs described in this document are specific to the distribution rate filing only.

Hydro One's current GIS software has been in place for roughly 15 years. Existing investments in the Enterprise GIS Program have enabled the integration of SAP and GIS achieving a synchronized, composite asset registry, including distribution and transmission assets, comprised of SAP and Hydro One's other major asset management systems. GIS infrastructure and software need to be updated periodically to take advantage of new functions and software performance improvements, and when possible to further enhance the technology to enable additional productivity in Hydro One's lines of business. All of the major vendor software components are reaching end-of-life during the planning period, and need to be replaced or upgraded. These products are no longer vendor supported after the end of 2017. Hydro One also proposes to address gaps and redundancies in business processes to author, maintain and utilize data from the geospatial databases.

Enhanced GIS functionality is needed to better support various business operations such as load forecasting, outage management, and protection and control, all of which help drive a more reliable network. The implementation of the unregistered easement public interface, for example, will reduce customer service staff effort to respond to numerous requests for assistance and complaints.

Increase in customer satisfaction and revenue are possible as more members of the public use the new easements search system. The integration of new customer-facing web maps would reduce calls to customer care to check rate class or associated concerns.

To summarize, the planned GIS work in the 2018 to 2022 period is comprised primarily of software replacement and / or technical upgrades, as well as moving the existing vendor (ESRI) software from the 10.1 to 10.4 version. One of the software components used for field design work (ArcFM) has reached end of life after 10 years in service and will be upgraded or replaced with a better / more cost-effective vendor solution.

Alternative 1: Status Quo

This alternative was considered and rejected because if this investment is not undertaken, the currency and quality of geospatial information will suffer and impact many key business functions.

For example, one impact of this is safety related. Up-to-date geospatial information resources assist safety practices as crews have easier access to accurate and timely views of the network model. Accurate GIS records complement HONI's Work Protection Code practices.

Alternative 2: Prudent Replacement of End of Life GIS Assets (Recommended)

Upgrade or replace the GIS system components and the integration between GIS and satellite systems it supports. Invest in new technologies that improve data governance and data quality, and leverage the GIS data to provide better and more useful information to the lines of business.

This investment is intended to both sustain the software at vendor release levels that the vendor is prepared to support, and to enhance the existing functionality through a series of projects from 2017 to 2022. Each project will be justified based on return-on-investment and related corporate objectives. Some of the planned enhancements are required to support the Work Management & Mobility investments for Provincial Lines and Forestry projects.

The proposal plans on the following:

- Software version upgrades to the vendor software that will no longer be supported after the end of 2017;
- Upgrade or replace the existing field design software (ArcFM) with a more modern package that provides better functionality and system performance at a cost per tablet lower than it is today;

- Conduct a discovery period to assess the value of implementing new SAP software that more seamlessly integrates Hydro One's map layers with the corresponding asset data in SAP; and
- Rationalize, where possible, the existing custom systems.

Investment Description:

The project will maintain and further strengthen Enterprise GIS as a single system of record comprising the location and connectivity of both transmission and distribution assets. GIS is the only technology that fully supports both logical connectivity and physical location of assets. It also supports asset properties and condition which facilitate planning and outage management, supports mobile workforce management through more effective crew routing, manages real estate records and Hydro One property, and provides the underpinnings of smart grid applications.

Over the years, as various asset-related systems have evolved at Hydro One, use of the GIS as system of record for location, connectivity and phasing has not always been respected. In some cases, complex bi-directional integrations have been built due to improper data governance practices and workflows. This investment focuses on remediating the inconsistent storage of location and connectivity between systems such as the Power System Database ("PSDB") and GIS as well as issues between the Customer Information System ("CIS") and GIS for storage of service point location. Both of these issues have led to increased cost to maintain overly-complicated integrations as well as the deterioration of data quality. Finally, some additional minor data governance issues with Health, Safety and Environment GIS data will be remediated.

Risk Mitigation:

For the version upgrade projects, lessons learned from a similar GIS software upgrade project that was carried out during 2012 and 2013 will be leveraged. This project was completed on budget and close to schedule, using some of the key Hydro One and Inergi resources who will be assigned to these projects. For the replacement of the field design software (ArcFM), an RFP will be issued to select the best value for replacement. Formal project delivery methodology will be applied to ensure adequate governance. The only known risk that could be considered significant is maintaining the data synchronization between the Corporate GIS data base and the SAP Asset inventory. The Information Technology Architects will be looking towards technology enhancements with SAP to centralize both the asset and GIS data in one location to minimize costs of maintaining data synchronization across multiple databases.

Result:

The core vendor software products will be upgraded during the period of this investment and, as is typical, will provide stability and the required level of vendor support for the next four to five years.

Outcome Summary:

Customer Focus	• Improved service to customers and Ontario property owners who should have access to information about outages and unregistered easements.
Operational Effectiveness	• Improved Decision Quality - Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions. • Improved productivity and reduced cost in both sustainment costs and labour.
Public Policy Responsiveness	
Financial Performance	

Costs:

The following costs are based on previous experience with the set of GIS software technical upgrades which occurred in 2012 and 2013.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	0.2	2.0	1.2	1.2	1.2	5.8	6.9
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**0.2**	**2.0**	**1.2**	**1.2**	**1.2**	**5.8**	**6.9**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**0.2**	**2.0**	**1.2**	**1.2**	**1.2**	**5.8**	**6.9**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-12 Business Process Consolidation

Start Date:		**Priority:**	Medium
In-Service Date:		**Plan Period Cost ($M):**	0.0
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The SAP Business Planning Consolidation (BPC) system is required to provide planning, budgeting, forecasting, and financial consolidation and reporting capabilities. The Investment planning maps projects & programs to specific strategic objectives. The budgeting process allocates funds to these investments. The forecasting process allows the company to track how the projects and programs are progressing.

The Business is currently using the BPC system which is a component of SAP Enterprise Performance Management portfolio and is designed to handle financial processes on a unified platform. The functional capabilities of the existing system are limited to project forecasting and legal and management consolidations.

Although Hydro One uses this application with available features, the system is not being used to its full potential due to numerous limitations. Specifically, enabled features do not support a fully integrated planning, budgeting and forecasting framework to enable continuous allocation of resources to support the business strategy and operational efficiency.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue its limited use of the BPC application. This is alternative does not allow for Hydro One to take advantage of process and operational efficiencies available through the application.

Alternative 2: Expand Use of BPC by Enabling Other Features and Functionality (Recommended)

This option would go ahead with implementation of the additional features available in the BPC application. Hydro One can continue to use the BPC system for project forecasting and legal consolidation and make use of additional functional capabilities that the system can enable, which are currently not being used.

This recommended option will allow Hydro One to fully realize the benefits of the BPC system by leveraging its potential of delivering planning, budgeting, forecasting, and financial consolidation capabilities in a single application. Hydro One will be able to adjust plans and forecasts, speed up budget and closing cycles, and ensure compliance with financial reporting standards. This in turn will bring about needed process and operational efficiencies.

Investment Description:

This project will provide enhancements to the current BPC system to become a unified & single planning & consolidation tool. It will add software and analytics features to realize additional business capabilities and benefits. These sought after capabilities include:

- What-if modeling and scenario planning to assess budget suitability in real time;
- Forecast models and to quickly update and adjust forecasts as needed;
- Automated aggregations, allocations, and other manual processes to speed up planning cycles; and
- What-if scenarios to allow the business user to identify quick course corrections.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

SAP BPC is a complex application and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

<u>Change Management and User Adoption</u>

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

Any combination of these risks could cause the project to be delayed and this will cause any of the following: Projects will be over-budget, behind schedule or will not deliver the scope it was intended to deliver. Solid project governance will be applied, taking into account the relevant 'lessons-learned' from other similar project in order to complete the project on-time and on-budget.

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities based on what-if analyses and scenario planning. It will improve accountability and planning accuracy. It will shorten cycle time, allows for financial information to be reported faster and align the company's plans with its strategic goals.

Outcome Summary:

Customer Focus	• Improve customer experience by providing timely budget and forecast data to the Business which will in turn improve the ability to manage programs and projects that affect customer-related investments.
Operational Effectiveness	• Improve decision-making capabilities and increase efficiency based on the ability to perform what-if analyses and scenario planning. • Improve accountability and planning accuracy due to shortened cycle time allowing for books to be closed faster.
Public Policy Responsiveness	• The outputs from the BPC system contribute to financial input used for regulatory agency reporting (e.g. OEB), government agency reporting (Ministry of Finance) and customer queries.
Financial Performance	• Improve financial performance and lower cost by reducing manual intervention.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management (such as training and job aids to the target user community wishing to access the new features), Project Management and Post Deployment. It includes vendor costs as well as direct LOB resource costs, and indirect costs of implementing the solution.

The cost estimate is based on a historical cost of enabling new functionality within the Consolidation Module of BPC. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One review process.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

Funding reduced to zero as the scope of work associated with this investment is now bundled as part of ISD-GP-17.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets			0.0	0.0		0.0
Less Removals						
Gross Investment Cost			0.0	0.0		0.0
Less Capital Contributions						
Net Investment Cost			**0.0**	**0.0**		**0.0**

Includes Overhead at Current Rates

GP-13 HR & Pay Related Technology Investments

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	8.7
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The Human Resources ("HR") Division is responsible for a range of functions in support various processes and activities such as employee time reporting, board and travel recruitment, payroll, Offer Letter Creation and Processing, master data management and search, information for employees and managers as well as reporting of employee-related issues.

The current HR and Payroll functions utilize native SAP ECC system features and transactions to fulfill above mentioned functions and processes. Currently, there's significant reliance on manual, fragmented and inefficient processes and tools.

The existing HR application framework poses numerous challenges and features many inefficiencies such as: Inadequate Knowledge Database for staff, inconsistencies and confusion around the multiple templates to be used, inadequate Knowledge Base Self Service for Managers and Employees, lack of a Case Management/Ticket-Tracking System, lack of an Automated Workflow for certain processes, reliance on a multitude of workarounds and customizations that are costly to sustain as well as insufficient HR metrics and analytics.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue to use the existing HR applications with their existing features.

This is not to Hydro One's advantage as there will be continued reliance on manual, fragmented and inefficient processes and tools. Also, this alternative would miss out on efficiencies and improved productivity opportunities.

Alternative 2: Implement Various System Enhancements (Recommended)

Hydro One would seek to leverage technology improvements and improve operational efficiency in the HR and Pay areas.

Hydro One will realize benefits such as a ticket tracking system for HR issues, a knowledge database for HR staff, managers & employees, automated letter creation & processing, an automated workflow for HR forms, mobility for HR applications, additional HR reports & analytics, online access to electronic pay advice and T4s, pay optimization, board & travel route optimization.

In addition, the intended enhancements will facilitate achieving the cultural change necessary to meet key strategic objectives.

Investment Description:

This investment is required to improve efficiency / productivity in the HR & Pay Area. This will be accomplished through 2 main initiatives.

<u>HR Process Optimization (start in 2018 & complete by 2019)</u>

This investment will address the following needs:

- Lack of a Case Management/ Ticket Tracking System for HR issues. In addition to improving the response time, this system will provide better insight into the types of issues coming to the HR Support Centre, which in turn allows HR to proactively respond to issues;
- Inadequate Knowledge Database for HR staff. By implementing a knowledge base comprised of answers to questions and solutions to problems from previous HR activities, this would reduce the amount of time spent by HR Assistants searching for information and thus improve response times;
- Inadequate Knowledge Base Self Service for Managers and Employees. This would provide quicker access to accurate HR information for employees and managers and minimize the time spent searching for information. Information will be more accurate and consistent;
- Manual Offer Letter Creation and Processing. This eliminates the requirement for multiple template letters to be drafted and maintained. It also reduces the amount of time involved in maintaining content for letters;

- Lack of an Automated Workflow for all HR forms/Smart Forms. A series of Smart Forms would improve efficiency and reduce errors in completing primarily by eliminating additional data input;
- Lack of Mobile Access to HR SAP applications. Mobile applications would provide HR Consultants, Managers and employees with more convenient access to information;
- Lack of Remote Recruitment Tool. Such a tool would reduce travel time for HR Consultants, Managers and employees; and
- Limited HR Metrics and Analytics. An analytics function would allow for improved reporting and analysis on HR issues to better inform decision making with clients.

<u>HR Pay - Phase 2 (start in 2018 & complete by 2019)</u>

Hydro One's payroll and master data management is managed using its SAP ECC system. Payroll business processes need to be further aligned with industry best practices and enhanced to fully utilize the available system capability for those processes which are currently administered through manual data entry. This investment is required to improve efficiency / productivity in the Pay and Time Reporting related processes by addressing the following needs:

- On-line Access to Electronic Pay Advice and T4s This would provide all employees an opportunity to access their pay advice and T4s online;
- Mobile/Remote Access for Time Reporting. This project would develop a mobile application that utilizes the Hydro One's SAP environment. The application will allow employees to access Time Self Serve (TSS) to input time via their smart phone or tablet and increase efficiency;
- Pay Optimization. HR would streamline current pay processes to utilize standard SAP functionality by removing workarounds and customizations that are costly to sustain; and
- Board & Travel Route Automation. This would allow the automatic creation of routes based on Google Maps. Routes are used to calculate amounts owing to Trades personnel to reimburse them for travel from home locations (or city centres) to assembly points.

Risk Mitigation:

<u>Solution Complexity</u>

HR and Pay Related Technology Enhancements are expected to be complex and finding the right skill set to support a successful implementation could be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and HR resources; all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to upgrade current HR and Payroll applications. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates. In addition, the project will be led by someone from the LOB who has deep expertise within the HR Process area.

Result:

This investment will yield operational efficiencies including enabling self-serve analytics and improved decision-making capabilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Improve HR performance by providing better insight to the types of issues coming to the HR Support Centre and better capabilities to address those issues. • Reduce travel time for HR Consultants, Managers and employees. • Allow for improved reporting and analysis on HR issues to better inform decision making with clients and with HR initiatives. • Allow for streamlined pay process & removal of work-arounds and customizations that are otherwise costly to maintain.
Public Policy Responsiveness	
Financial Performance	• Due to integrations in the system & better access to information, this translates to improved decision making abilities which in turn can lead to better financial performance.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as Hydro One direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex SAP changes. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

Investment was accelerated to align with the end date of current Hydro One's Outsourcing Agreement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.5	6.2	0.0	0.0	0.0	8.7
Less Removals						
Gross Investment Cost	2.5	6.2	0.0	0.0	0.0	8.7
Less Capital Contributions						
Net Investment Cost	**2.5**	**6.2**	**0.0**	**0.0**	**0.0**	**8.7**

Includes Overheads at Current Rates

GP-14 Warehouse Scanning Device Replacement

Start Date:		**Priority:**	Medium
In-Service Date:		**Plan Period Cost ($M):**	0.0
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

In order to effectively perform material and inventory handling operations, Hydro One has been using Bar Code technology at its warehouses since 2011. A barcode is an optical, machine-readable, representation of data. Using a scanning device (typically hand-held), the bar code is scanned and this provides information about the material such as type, quantity, price. As the information is automatically acquired through the barcode, it minimizes errors and increases speed compared to key entry. This makes operations at the warehouse more efficient.

By 2019, the current system will be at its end of life. As a result, there will either be limited or no vendor support for the scanning device and system that Hydro One uses. In addition, there have been many advances in bar coding technology that would make warehouse operations more efficient but the current system cannot take advantage of these improvements.

Alternative 1: Status Quo

This alternative continues to use the current equipment past its forecast end-of-life.

Maintaining the status quo leads to the business continuity risk of relying on a system and equipment that may no longer be supported by the vendor. Status quo is therefore not a recommended option.

Alternative 2: Upgrade Bar Code Technology (Recommended)

This alternative upgrades the bar coding equipment used at Hydro One warehouses.

By upgrading the bar code technology, Hydro One will be able to leverage improvements in technology in this area. It is anticipated that the technology will provide better tracking of inventory within Hydro One's Barrie Warehouse and Central Maintenance

Shop but also at the various remote field sites including offsite storage depots and construction project sites. This will bring about higher accuracy for tracking of available inventory.

Investment Description:

This investment will upgrade the bar coding devices used at the Barrie Warehouse & Central Maintenance with up-to-date mobile applications that sit atop the approved tablet infrastructure.

Risk Mitigation:

Solution Complexity

Upgrading the Bar Code Technology is expected to be complex and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Supply Chain resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities.

Change Management and User Adoption

The goal of this project is to upgrade or replace its current warehouse scanning device with a more current version. This could potentially pose both process and technology challenges to impacted staff particularly at the Barrie Warehouse, Central Maintenance as well as several other remote locations as they learn to use the technology.

Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

In addition, the project will be led by someone from the LOB who has deep expertise within the Supply Chain and Warehouse area.

The timing took into consideration that the last time the bar code technology was implemented at Hydro One was in 2011. Typical software lifespan is 5 – 7 years. By 2019, it would already be time for Hydro One to upgrade to a more current version or replace its current warehouse scanning device with a new technology or solution.

Result:

This investment will yield operational efficiencies. By proceeding with this investment, Hydro One will be able to monitor its inventory with better accuracy and speed, leading to greater efficiency.

Outcome Summary:

Customer Focus	• Improve customer experience by providing efficient material availability to the Business which will in turn improve the ability to deliver timely programs and projects that affect customer-related investments.
Operational Effectiveness	• Provide accurate inventory count within warehouses and in remote field depots and construction sites.
Public Policy Responsiveness	
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on historical estimate of when Hydro One last implemented bar coding technology. When the discovery phase is complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

This investment has been cancelled to reflect change in business priority.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.0	0.0	0.0	0.0	0.0	0.0
Less Removals						
Gross Investment Cost	0.0	0.0	0.0	0.0	0.0	0.0
Less Capital Contributions						
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Includes Overheads at current rates.

GP-15 SAP Treasury Implementation

Start Date:		**Priority:**	Medium
In-Service Date:		**Plan Period Cost ($M):**	0.0
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

Treasury Management includes management of enterprise's debt, cash and short-term investments, currency and derivatives exposures, with the ultimate goal of managing the Company's liquidity and mitigating its operational, financial and reputational risk. Common Treasury functions include cash flow forecasting, investment recording and settlements as well as financial reporting. Treasury functions support all lines of business at Hydro One.

Currently, the business operates on a Sungard Integrity v.8.2 platform while most of Hydro One's finance functions operate on the SAP platform. Vendor support for the current Treasury system (Sungard Integrity) ended in December 2016. The company needs to upgrade to Integrity v.8.5 by April 2017 in order to retain vendor support.

There are certain intercompany transactions generated by Treasury in Sungard Integrity that impact the general ledger in SAP. This interaction of data requires technical interfaces between the two different systems, increasing complexity and reducing processing time efficiency.

Alternative 1: Status Quo

This alternative would continue to use Sungard's Integrity application.

Integration between Integrity and SAP will continue to be via batch process rather than real-time. With real-time processing, data is processed immediately when it is received. As a result, data is more up-to-date and potentially more accurate as data can be accessed and corrected immediately by the user. Batch processing, on the other hand, takes time to process. If there are errors, these are typically not caught immediately.

Alternative 2: Implement SAP Treasury & Risk Management (Recommended)

This alternative proposes to replace Sungard Integrity with the implementation of a new SAP Treasury and Risk Management (TRM) module. The estimated cost for licensing is $1 million with an associated maintenance of $220,000 per year (22% of the license cost). Implementation costs were based (business case estimate) on a medium sized complex new SAP module.

The Licensing, implementation, and first year maintenance costs are considered to be a capital cost. Maintenance costs from year 2 onwards would be considered an OM&A cost.

This investment improves business performance through:

- Using standard SAP automated processes for cash and liquidity management, risk analysis and transaction management. Access to real time accounts receivable and accounts payable payment data in SAP will help improve cash flow forecasting and working capital management;
- Simplifying integration and movement of data with existing SAP core financial modules;
- Real time availability of data permits mitigation of issues and errors throughout the month rather than only at the end of the month. This will help Corporate Accounting meet aggressive deadlines;
- Reducing manual work by sending wire and EFT payments directly from SAP to the banks;
- Eliminating manual process in valuation of derivatives and managing exposures by direct feed of valuation data to SAP for financial reporting; and
- Timely update of bank transactions data in SAP for bank account reconciliations to identify any unusual transactions.

Investment Description:

The implementation of SAP Treasury & Risk Management includes the SAP modules: Cash and Liquidity Management; In House Banking; Bank Communication Management; Treasury and Risk; Hedge Management.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

The implementation of the SAP Treasury and Risk Management module is expected to be complex and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

<u>Change Management and User Adoption</u>

The goal of this project is to replace its existing treasury system with SAP. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities. The SAP Treasury and Risk Management module will provide the Treasury department with a functionally complete set of solutions to support Hydro One's business. Being an SAP integrated solution will promote the harmonization of the system landscape and application rationalization. In addition, integrations between Treasury and other SAP modules will move away from batch processing towards real-time processing, which improves productivity, processing efficiencies and decision-making abilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Simplify the application landscape and integrate more tightly with the existing core SAP solutions. • Increase efficiency through reduced interface requirements, real-time data availability and the leveraging of recent technology upgrades in the SAP stack.
Public Policy Responsiveness	
Financial Performance	• Reduce reliance on IT support by migrating to a common enterprise platform that allows direct access data. • Improve financial management of Hydro One's debt, cash, short term investments, currency and derivatives.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs, as well as Hydro One's direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex new SAP module. When discovery phases are complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are appropriate. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

Funding reduced to zero as the scope of work associated with this investment is now bundled as part of ISD-GP-17.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	0.0	0.0	-	-	0.0
Less Removals	-	-	-	-	-	-
Gross Investment Cost	-	0.0	0.0	-	-	0.0
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	-	**0.0**	**0.0**	-	-	**0.0**

Includes overheads at current rates.

GP-17 S4 HANA for Finance

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	15.4
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

IT Need

SAP has announced that they will stop improving the current enterprise BI platforms immediately and vendor support for the current platform altogether will end in 2025. SAP will shift development to their new SAP S/4 HANA platform. All business functions performed on the current platform will ultimately have to migrate to the new platform.

Business Need – Finance

Multiple systems are required to produce the monthly financial statements at Hydro One. They include SAP BI, SAP ECC, SAP BPC and MS Excel. This drives delay and complexity into the month end processes.

The company faces higher requirements for financial reporting and has a need for improved month end, quarterly and year-end financial reporting procedures and processes.

SAP has, over the past 3 decades, created a platform that can be configured to perform any one business function in multiple ways. While "best practice" has always been built into every SAP transaction, user interpretation of what data needs to input has led to inconsistent transaction processing and erroneous or missing data. SAP has re-architected the Enterprise Resource Planning (“ERP”) system, consolidated into ERP the financial functions that currently reside on the BI system, streamlined the financial consolidation processes and simplified the reporting functions. Business Planning has been moved from BW (business warehouse) and incorporated directly into the SAP ERP platform. This means that the impact of planning changes can be immediately reviewed.

More recently, further improvements have taken place in the continued simplification of processes that removes the need for data replication. This provides end users with faster access to data to generate real time reporting and ultimately reduce the time to close the books by 10 – 20% according to SAP estimates. Additionally, new systems provide the ability to facilitate predictive forecasts and dynamic simulations using real time data to provide greater reasonability to the numbers. Embedded predictive algorithms and simulation capabilities enable management to better monitor and forecast business needs.

Alternative 1: Status Quo

This alternative would continue to use the current BI and ECC platforms in conjunction with other applications to produce statements and reporting.

IT

The current SAP platform will reach end of life status, by 2025 at which time SAP will cease providing any support for the current platform.

Business

Continue to plan and manage and report financials in less than optimal manner.

Alternative 2: Replace SAP with an alternative software system

This alternative would replace the current SAP BI platform with competing ERP software and/or adopt a multi-vendor approach by replacing the various business functions with Commercial off-the-shelf (“COTS”) applications.

Not justifiable due to the investment Hydro One has made in SAP.

Alternative 3: Migrate to the S/4 HANA platform (Recommended)

IT Benefit

Migrating to S/4 HANA will ensure continued vendor support to reduce IT costs and ensure ongoing, timely performance.

Business Benefit General

Hydro One has significant investment and experience in implementing and maintaining SAP. Over the past 10 years, Hydro One has consolidated over 130 applications, and the functions they performed, into SAP leading to IT and business process savings.

S/4 HANA is proven to offer superior query performance, faster load times thus increasing performance in the numerous business areas that use the ECC platform.

S/4 HANA has a streamlined user interface which has been built upon the same design concept that most mobile applications use which is to present the user with exactly the data they require and limit input options. On the S4 HANA platform business functions or processes have been simplified resulting in less time required to perform the associated processes and improved data quality. The database structures have been greatly simplified. SAP has done away with the sub ledger/ledger construct thus increasing performance.

Business Benefit Finance

Over and above the general business benefits finance functions such as business planning, consolidation and disclosure, financial accounting and financial reporting have been consolidated on the S4. This will reduce the time required perform many of the finance processes.

Investment Description:

Planned investments include HANA which is SAP's new database technology; S4 which is SAP's new application software, SAP's new software configuration guides. This investment will also include, but is not limited to: integration with other enterprise systems; and data migration of financial data from the existing ECC to the new S4. With S4 Finance the business planning and consolidation (BPC) functions that used to be performed on SAP BW have been incorporated into S4 Finance. Data will have to be migrated to S4 from ECC and BPC. When complete all Finance functions can be performed in S4. The S4 version of BPC offers improved plan and forecast capabilities.

This investment will not be impacted by other investments such as SAP Treasury, Business Planning and Consolidation and others. However, it should be noted that anything added to SAP through some other investment will ultimately have to be migrated into SAP and implementation collisions must be managed.

Risk Mitigation:

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

The SAP HANA delivery is expected to be a complex implementation and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

Configuration guides will remove significant amounts of implementation inconsistency normally introduced by 3rd party implementers.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP, and Enterprise Architecture resources. All of these resources are integral to success of the project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Any combination of these risks could result in a project in-servicing delay. To minimize the risk, solid project governance will be applied taking into account the relevant lessons-learned from other similar projects.

Result:

This investment will yield operational efficiencies, improved decision-making through real time reporting, process simplification, better data driven by standard and consistently performed transactions, better user adoption due to a simpler and modern interface.

Outcome Summary:

Customer Focus	• Leverage out-of-the-box, customer functions that represent the full spectrum of utility customer interactions.
Operational Effectiveness	• Increase operational effectiveness through simplified user interfaces, superior performance and more consistent processes. • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting
Public Policy Responsiveness	• Improve capability to meet statutory reporting capabilities.
Financial Performance	• Reduce the inconsistencies in month end reporting through simpler user interfaces and consistent process execution.

Costs:

The underlying premise is that S/4 HANA will help us fine tune what we have today, not reinvent it. This will extend the investment in the current SAP ERP that was implemented in phases between 2008 and 2013. The cost estimate for this investment assumes the use of the standardised configuration and that the project will be based on migrating data from our existing ERP platform to the new S/4 HANA platform, without the need for lengthy business requirements gathering and interpretation. This is what commonly results in very expensive SAP implementations.

Hydro One will also launch an open competition so multiple vendors can submit their proposals and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

Funding increased to include the scope of work associated with ISD-GP-12 and ISD-GP-15 within this investment.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.5	1.0	3.8	3.7	6.3	15.4
Less Removals						
Gross Investment Cost	**0.5**	**1.0**	**3.8**	**3.7**	**6.3**	**15.4**
Less Capital Contributions						
Net Investment Cost	**0.5**	**1.0**	**3.8**	**3.7**	**6.3**	**15.4**

Includes overheads at current rates.

GP-18 Integrated System Operating Centre

Start Date:	Q1 2015	**Priority:**	High
In-Service Date:	Q3 2020	**Plan Period Cost ($M):**	61.3
Primary Trigger:	Asset Driven – Failure Risk & Capacity		
Secondary Trigger:	Regulatory		

Investment Need:

The Network Operating Divisions (“NOD”) Backup Control Centre (“BUCC”) facility was placed in-service in 1956, and is the means that regulatory, business and operational requirements are sustained for monitoring and control operations to North American Electricity Reliability Corporation (“NERC”) standards, Distribution and Transmission System Code (“DSC”) requirements and Hydro One standards respectively. The BUCC facility consists of the building, computer tools and systems that support Operations in the event of a partial or total loss of the primary Ontario Grid Control Centre.

A risk of future extended outages, inability to execute necessary upgrades /replacements and increase capacity to required computer systems and tools, could result in significant disruption to business continuity and Hydro One’s ability to meet customer’s service level expectations. The facility is currently at capacity in computing space, HVAC, power and due to the age of the structure, among other factors, remedial efforts are either not viable alternatives, cannot be mitigated or are cost prohibitive to execute. In addition, a prolonged activation would impede supporting Operations; i.e., Outage Planning, Operations studies and support due to a lack of back office support space. Current Operations support groups that are fundamental in daily Operations, are unable to occupy the BUCC during any event, and would require current staff at the Richview facility to be relocated, procurement and set up of required computer equipment and would take vital time to implement.

Alternative 1: Status Quo/ Use Offsite Leased Space

Hydro One Network Operating maintains the existing Control Room, and Security Operations maintain existing facilities. A new offsite leased Data Centre facility (to mirror capacity of OGCC data centre based on 20 year lease and initial setup costs) could be provisioned and additional office space would be required and furnished for prolonged activations. This alternative includes additional leased space for the Backup Integrated Telecommunications Management Centre’s (“BUITMC”) control room and compute needs.

The total cost of this option is estimated to be $78M, of which, the distribution portion will be 50.07%.

This alternative has been rejected as the current BUCC for Network Operating and the Backup ITMC do not meet operational requirements.

- The current facility imposes a high level of risk to both regulatory compliance and, Hydro One's reputation and customers, if any failures are experienced.
- This alternative fails to provide for the Security Operations Centre's ("SOC") need for an adequate primary control centre.
- Even with extensive investment in the existing facilities, this option does not adequately remediate all risk factors (e.g., basement flooding, power capacity constraints, electrical hazards due to proximity to TS).
- This alternative cannot accommodate current or projected growth, requiring further investment in leased facilities in the future.
- This alternative would require the relocation of the existing compute space and critical support infrastructure, currently housed at the BUCC, to a new leased BUITMC.
- This alternative cannot mitigate all known risks due to site conditions, size and location. In the event of a prolonged activation, some existing staff of the Richview facility would be asked to leave to make space for operating activities, and even if this arrangement can be made, there is not sufficient onsite parking, work space, or basic facility infrastructure for the overflow of staff.

Further information relating to the rejection of Alternative 1 is found on pages 22-24 of this Investment Summary Document.

Alternative 2: Build NOD Backup Control Centre and Data Centre exclusively.

This alternative was reviewed in light of the 2013 Toronto rainstorm and ensuing flooding that occurred in the GTA. This event required the ITMC to activate the BUITMC located in Kitchener Ontario. During this event, it was made apparent that a failure in the ITMC function or delays in Backup activation, created an inability to remediate, troubleshoot telecommunication outages, and had a significant impact on Network Operating's ability to monitor and control. Loss of communications had severe impacts on the Control Room's ability to monitor and control field assets and clearly showed that a new NOD Backup Control Centre and Data Centre would not remediate all risks currently identified. This alternative proved that a more robust BUITMC is required.

Due to the importance of the ITMC, the identified need for a new BUITMC and the economies that would be foregone with this alternative, this alternative was removed from further consideration. The estimate for this alternative is $104.8M, of which, the distribution portion will be 50.07%.

Alternative 3: Build Backup Control Centre's for Hydro One Networks and ITMC including shared critical infrastructure, back office support areas and an integrated Data Centre.

This alternative includes Control Rooms, an integrated Data Centre and shared back office support areas for prolonged activation and is considered the minimum requirement to address known operational risks that currently exist. This alternative also includes the purchase of the preferred site. This alternative is estimated at a cost of $124.7M, of which, the distribution portion will be 50.07%.

While this alternative meets Network Operating and the Integrated Telecommunications Management Centre's minimum requirements, it has been rejected as it fails to maximize investment utilization through synergistic lines of business occupancy as well as shared use of critical infrastructure. The incremental cost of the SOC inclusion is $ 6.5M. This also fails to take advantage of operation synergies for operational response to security threats, both physical and cyber.

Alternative 4: Acquire an existing facility that could be retrofitted / utilized to accommodate NOD Backup Control Centre, BUITMC and an integrated Date Centre.

A market assessment was completed that reviewed potential sites against identified requirements for size, location, travel times, power infrastructure, telecommunications and occupancy. This also included an internal assessment of Hydro One owned sites. At the completion of the assessment, it was determined that no suitable site was available in the market or within Hydro One's owned locations. As a result, this alternative was excluded from further consideration.

Retrofitting an existing facility was also considered. In order to suit the environments and critical support infrastructure required for Data Centre reliability, real time 24x7 Control Rooms, Security considerations including dual power supply and telecommunications expansions, extensive investment would be required. At the time of the assessment, no suitable site / facility was available and as such it was removed from further consideration. In addition, the total cost to retrofit was anticipated to be equal to or greater than greenfield construction and as such was removed from further consideration.

Alternative 5: Build ISOC with incremental capacity for a Primary NOD Control Centre, SOC Primary Centre, and BUITMC including an Integrated Data Centre, Shared critical support infrastructure and back office support space.

This option involves building the ISOC as described in alternative 6 and making the necessary arrangements to utilize the ISOC as the Primary Operating Control Centre from Day 1. The OGCC, which is the existing primary operating control centre, will then be converted to be the backup centre.

The additional cost for the building, site and the uplift / upgrades to current mission critical Operating systems and IT architecture to initiate the ISOC as a primary NOD Control Centre, from inception, was determined to be high when weighed against the initial benefits; therefore, this option was rejected. The total cost of this option is estimated to be $141.9M, of which, the distribution portion will be 50.07%.

A strategy to enable a “Dual Control” operational strategy was pursued in an effort to leverage current upgrade investments for their useful life. This alternative does not facilitate the Dual-Control strategy and, without costly upgrades, there will not allow the transition to occur in a more organic nature, representing less cost impacts and less disruption to the Operating functions and staff.

Alternative 6: (Recommended) Initiate Build of the Integrated System Operations Centre (ISOC).

This alternative provides for:

1. a Network Operating Control Centre;
2. a Backup Control Centre for the Integrated Telecommunications Management Centre; and
3. primary facilities for Security Operations.

This Alternative also includes the provision for a shared integrated Data Centre, all critical support infrastructures at the preferred site. This alternative will maximize Operational flexibility for Hydro One Networks and associated lines of business while eliminating the need to duplicate investments in multiple sites, and costly critical support infrastructure (emergency generators, uninterrupted power supplies, telecommunications etc.). The total distribution share of this option is estimated to be $69.3M, and the specific amount for this plan period would be $61.3M.

The ISOC strategy will enable a "Dual Primary" scenario where both Centres can be live as compared to the current live/passive (standby) model. Functionality required to facilitate this strategy is not expected until 2022 and will be implemented within current/future lifecycle schedules for the primary applications (i.e. ORMS, DMS, NMS etc.). This effectively negates the need to prematurely replace, re-architect and implement newer systems prior to their lifecycle expiration while providing the benefits and future flexibility of Primary Control ability.

Further details about the project are included in Appendix A.

A detailed option comparison is included in Appendix B.

Investment Description:

The Integrated System Operations Centre will house multiple lines of business through the provision of dedicated Control Centres: an integrated Data Centre and shared back office areas. This facility will be a hardened facility employing emergency preparedness criterion, industry best practices that meets physical and cyber security standards. This strategy provides flexibility for Hydro One Networks to enable future dual control through a systematic and cost effective approach with planned lifecycle upgrades. These facilities are essential in maintaining adequate redundancy for Operation of the Bulk Electric System, management of the Distribution network and associated customer responsiveness (i.e., outage and storm management). In addition, this will ensure Telecom Communication Network management and adherence to mandated North American Electricity Reliability Corporation (NERC) requirements for Emergency Operating Procedure 008-1 "Loss of Control Centre Functionality". It ensures achievement of reliability and availability targets commensurate with the criticality of these facilities. The ISOC will provide in house security operations, mitigating reliance on third party services and provides needed compute capacity for Security Event Monitoring (SEM).

The ISOC design provides the following:

Facility:

- Provide NOD with a new backup control centre including a control room, back office space and a shared data centre, employing the following strategies; provides the operating flexibility that allows Network Operating to duplicate the current OGCC functionality mitigating the current heightened risk profile with the current BUCC.

- Provides additional training synergies through the use of simulation technologies, allowing use of the facility while not required for backup activation (dual purpose).
- Enables future dual control potential, increasing the readiness and customer response times for any future event that may impact the Ontario Grid Control Centre and NODs ability to manage, monitor, control and dispatch on the distribution system.
- Ensures security requirements, both physical and cyber, including a hardened facility to guard against physical and environmental threats (i.e., tornadoes).
- Provides the ITMC with a new backup operations control centre including a control room, back office and integrated computing facilities mitigating the current risks at the BUITMC and the risks a failure of ITMC Operations poses on Network Operating.
- Provide the Security Event Management centre with needed integrated computing facilities.
- Provide Security Operations with a headquarter location including a control centre, office space, investigative rooms, emergency operations centre (room) and integrated computing facilities.
- Shared and redundant critical support infrastructure.

The total distribution portion cost of the construction build, including contingency and escalation, is estimated to be $51.7M.

Site:

Provides a 16.4 acre site in Orillia Ontario at a cost of $3.0M, and 50.07% of this is the total distribution portion cost. The site was selected based on an extensive Market Assessment in Q1 of 2015. The Orillia site met essential criteria, and included material advantages and associated cost savings in terms of; location, current site development activities completed, forgoing of water detention requirements, improved commute and activation times, and significant municipal development charge savings realized through the Industrial Development Charge Moratorium offered by the City of Orillia.

Architecture and IT design:

The detailed design is expected to be completed by the middle of 2017. The distribution portion of the total engineering and IT consultant costs, for the detailed design, is estimated at $4.9M.

Connectivity and Telecommunication:

Connectivity and SONET at the new ISOC facility allows the ISOC data center to communicate with the OGCC and the rest of the Hydro One telecommunication network. The distribution portion cost to establish this communication connectivity and SONET is estimated to be at $3.6M.

Network Infrastructure:

Lastly, an additional $7.6 million (distribution portion only) has been budgeted for IT infrastructure. This covers the cost associated with connecting each individual workstation console to the ISOC data hall.

Compliance

In order for Hydro One Network Operating to be compliant, there are many requirements, Regulatory Standards and internal Hydro One Standards that must be satisfied. In addition, industry best practices are respected to build on reliability and availability of critical system. The ISOC investment must adhere to; but not limited to the following:

1. North American Energy Reliability Corporation (NERC) –EOP-008 "Loss of Control Centre Functionality" necessitating backup activation to be equal to or less than two hours.
    a. In a related Federal Energy Regulatory Commission (FERC) order (Docket No. RD11-4-000 at 14) FERC signalled its concern that the two hour activation requirement is too long and that "it is imperative that full backup functionality occur as soon as possible after the loss of primary control functionality". FERC also noted that "…it may revisit this transition timeframe". This signalled that the new BUCC facility must take into consideration that activation timelines could be reduced in the future.
    b. NERC and FERC also require the Backup to be "capable of operating for a prolonged period and providing functionality sufficient to maintain compliance with all reliability standards that depend on primary control functionality."
2. Restoration Participant Attachment as required by the IESO administered 'Market Rules' for the Ontario Power System Restoration Plan (OPSRP).
    a. The BUCC is listed as one of the key facilities which comprise Hydro One's contribution to the Ontario Basic Minimum Power System.

3. Required as per EOP-005-2 NPCC-D8 (NPCC Directory 8) and IESO Market Rules & Manuals (Market Rules Chapter 5 – Power System Reliability, Market Manual 7: System Operations, Part 7.8: Ontario Power System Restoration Plan.
4. NERC Critical Infrastructure Protection (CIP) Requirements – ensuring assets are protected logically (electronic security perimeter) and physically (physical security perimeter).
5. Communications: NERC & IESO Market Rules:
   - NERC-COM-001-2;
   - Chapter 2, Appendix 2.2, Section 1.1.4- Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities;
   - Chapter 2, Appendix 2.2, Section 1.2.3 – Transmitter Submission to the Energy Management System;
   - Chapter 5, Section 12.1.1 – Voice Communications Methods;
   - Chapter 5, Section 12.1.6 & Section 12.2.12 – Alternatives During Loss of Communications;
   - Chapter 5, Section 12.2.3 – Required Voice Communication Facilities;
   - Chapter 5, Section 12.2.4 – Voice Communication Reliability;
   - Chapter 5, Section 12.2.11 - Voice Communication Monitoring and Testing; and
   - Chapter 5, Section 12.3.2 - Required Data Communication Facilities.

<u>Additional Design Criteria</u>

In addition to the above requirements, the following Industry Best Practices have been incorporated into the ISOC design:

- Designed for Dual Hot Centre's with Increased Security
  - Provides additional functionality that improves operational proficiency;
  - Improved system security and redundancy; and
  - Meets minimum provincial anti-terrorism standards (i.e., blast protection).
- Multifunctional Facility / Business Continuity
  - Increased building utilization (multipurpose, real time, simulation and future Dual Control);
  - Operational flexibility and scalability (modular expansion); and
  - Emergency Preparedness criteria – facility separation for common mode failure.
- High Availability / Reliability 99.95%
  - Employing an Uptime Institute guiding principles for a Tier III facility; and
  - Provides for redundancy in computing, communications, cooling and power.

- Emergency Preparedness risk considerations were factored into site selection and facility design, mitigating the current risk the BUCC is exposed to (i.e., not in a flight path, transformer station, etc.).

Risk Mitigation:

- Construction commencement is contingent on the required OEB approvals and if not planned accordingly, could pose project schedule risk. This has been mitigated through a schedule adjustment that will initiate commencement in alignment with OEB schedules.
- Municipal Approvals impose risk to the project schedule however during the current detailed design stage, the municipality has been consulted throughout the process mitigating the risk of future change requests or delay for approvals.
- Site development and environmental risk due to discovery of adverse subsoil conditions. This risk has been mitigated through several borehole assessments of subgrade soil conditions to determine: (a) foreign objects; (b) soil contaminants; and (c) suitability of soil cohesion for adequate foundation strength and no notable issues have been discovered.
- Construction risk due to change requests, lack of performance of proponent and increased costs have been mitigated through plans for Hydro One's and the external designer monitoring on site activities throughout construction ensuring issues are discovered and addressed early and that required contract quality is delivered to schedule.
- Alignment of dependent sub-projects has been identified as a potential risk as a delay in delivery of communication path connectivity to the control network would delay future in-service and commissioning activities. This risk is mitigated through early commencement of this activity to ensure adequate lead times.
- Factors affecting implementation timing and priority are those identified in the Investment need section which speak to the increased reliability risk for backup Operations. These factors have been reviewed and the priority has been set to "high" given the high cost for remedial efforts and the impacts on Operations and Hydro One customers if further failures are experienced.

Result:

The integrated strategy behind the ISOC facility maximizes investment utilization as well as value generated by eliminating the need for additional sites and facilities that would otherwise be required. By building one centralized site to house all stakeholders, economies of scale synergies will be realized. These come in the form of negating the need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment, limiting overall rate impacts.

All proposed tenants require critical support infrastructure to meet an availability target commensurate with the criticality of the systems and functions they support (99.95%). The requirements are prescribed by Hydro One internal reliability standards and guided by industry best practices (Uptime Institute Availability "Tier" levels). Critical support infrastructure and IT investment to achieve this objective represent significant investment. With the current ISOC strategy, critical support infrastructure is shared and represents incremental cost to achieve rather than replicating with several installations that would be required to support several sites across Ontario.

- Enhanced monitoring, control and coordinated Customer response (Operating, ITMC, Security and Emergency Preparedness);
- Examples include;
    - Coordinated response for all system vulnerabilities i.e. system events, telecommunication events, cyber events or physical threats through integrated communication within the ISOC facility.
    - Enables future dual active sites, removing activation timelines of backup Operations.
- Share enhanced building protection design and security (physical facility hardening to protect against severe weather or man made threats);
- Share redundant backup generator power supply and other emergency supplies;
- Enhanced site location for improved activation response, elimination of NOD's interim BUCC, adherence to emergency preparedness criteria, dual purpose use for training (negating need for additional training facilities) and other business operations; and
- Enhanced security with centralized operations, improved monitoring and analysis trending for proactive response, and situational awareness for coordinated resolution. An Emergency Operations Centre for Business Continuity and Emergency Preparedness will also be provisioned as part of the Security Operations Centre.

Outcome Summary:

Customer Focus	• Improve the reliability and availability of emergency activation, response and restoration in the event any failure is experienced in the Primary Control Centres. • Reduced rate impacts from a single integrated solution as compared to multiple standalone investments. • Retiring of the current interim NOD BUCC and removal of the risk of costly remedial efforts in the event further failures are experienced.
Operational Effectiveness	• Mitigates the critical risks (infrastructure failures, capacity constraints, location and activation timelines etc.) that exist at the Network Operating Backup Control Centre and the Backup Integrated Telecommunication Management Centre. • Monitoring and control reliability will be sustained under all system contingency scenarios improving Hydro One's compliance risk, customer responsiveness and Operational agility.
Public Policy Responsiveness	• Accommodate all regulatory requirements for physical protection, cyber security and activation timelines responsiveness. (See Appendix A and Compliance section of this document for further details).
Financial Performance	• Reduce the cost impact to Hydro One customers through the realization of economies of scale, mitigating the need to provide multiple sites, buildings and shared critical support infrastructure. • Negate the need to maintain an Interim NOD BUCC and reduce the risk of costly mitigation in the event additional failures are experienced at the main BUCC.

Costs:

Key considerations affecting the final cost of the project consist of the following:

- Availability and Reliability Standards including the need for redundancy in system and building architecture to maintain the existing target of 99.95%. The largest cost element revolves around the Data Center and critical support infrastructure, and the “Tier” or “Redundancy” level can weigh heavily on the investment required. Given the criticality of the Control Centre functions, with leading industry advice, a Tier III level was recommended and designed. This category includes the investment required in the SONET control telecommunications network required to connect the BUCC to field assets for monitoring and control.

- Security Requirements impose additional cost considerations ensuring the facility can withstand both natural and human events i.e. Tornado's, blast protections. Included in this consideration are prescribed regulatory requirements for six sided secure perimeters, cyber security (IT architecture), site access and monitoring of critical assets.
- Costs have been managed through an extensive and thorough assessment with various third party industry experts, internal subject matter experts as it relates to industry best practices, cost saving initiatives (i.e., free cooling), alternative option assessment for independent project elements (site selection, industry comparators), integration of solutions for various business units, functions and needs across Hydro One at a single site. An independent cost consultant has provided costing of the current stage of detail designs.

Variance due to refinement of the IT, Telecom, and construction engineering cost estimates as the engineering design had been finalized.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	22.0	36.3	3.1	-	-	61.3	69.3
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**22.0**	**36.3**	**3.1**	-	-	**61.3**	**69.3**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**22.0**	**36.3**	**3.1**	**0**	**0.0**	**61.3**	**69.3**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

APPENDIX A – DETAILED PROJECT DESCRIPTION

This investment, formerly known as the Backup Control Centre – New Facility Development, has expanded to include other operational synergistic lines of business that require facilities to perform similar functions (operating, monitoring, control and response functions) that are critical to support Network Operating and to secure Hydro One's assets. An integrated solution was sought to ensure costs are minimized, maximizing the effective utilization of critical infrastructure, office space and the site with the intent to maximize capital investments and reducing customer rate impacts. Below is a description of the Security Operations (SOC), Security Event Monitoring (SEM) and the Integrated Telecommunications Management Centre (ITMC) identified investment need.

The Backup Integrated Telecommunications Management Centre (BUITMC), in-serviced in 1950, requires extensive setup during activation and cannot accommodate back office support staff and regulatory security requirements for access control for critical computing equipment. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure. In the event the ITMC cannot meet its service objectives, and Hydro One experiences an issue with telecommunications paths, Network Operating will be unable to monitor or control the respective field assets. ITMC requires a new Backup Control Centre to alleviate the risk at the current location.

Security Event Monitoring (SEM) is accountable to provide cyber surveillance monitoring services and requires Data Centre capacity, (not a physical tenant) to support primary and backup operations. SEM monitors Network Operating's Compute Network to ensure threats are detected, assessed and remediated so that critical cyber assets are not negatively impacted. Loss of visibility, control or erroneous operations of equipment due to a cyber-vulnerability, poses a serious threat to Hydro One's Operating functions. The risk of cyber related events has increased rapidly due to the relative increase in the amount of IT critical cyber assets employed in Hydro One Networks.

A Security Operations Centre (SOC) and an Emergency Operating Centre are required to provide a primary site for operations, monitoring and coordinated response for physical security threats and are imperative for business continuity. Currently, Security Operations are dispersed across the province and is reliant on third party services. In the event the current vendor cannot meet service obligations, Hydro One will be unable to monitor its critical sites. An integrated security presence at the ISOC will ensure physical threats can be detected, assessed and appropriate response dispatched. If a physical threat goes undetected, catastrophic impacts can result, in the event critical assets are damaged, which has potential to result in sever impacts to the Transmission and Distribution system networks. In addition, a lack of detection has potential to expose Hydro One to safety and environment risk for staff and the general public.

The current ISOC investment has evolved through a significant collaborative effort with Hydro One Network Operating, ITMC, SEM, Security Operations, industry participants and external subject matter experts. Initiation of this investment was predicated on current asset driven deficiencies / requirements (documented safety hazards, capability constraints, Reliability/Performance Impacts and risks, failures, condition, age, obsolescence, and regulatory and/or Hydro One standards (as described above).

Below is a detailed description of the ISOC investment planning process and execution strategy, which has been developed with the aim to a) fully understand requirements and needs across Hydro One; b) gather leading industry best practices, lessons learned; c) develop detailed programmed space and sizing requirement and asses against industry benchmarks; d) project costing from leading industry experts; e) ensures cost controls and oversight.

Planning Needs Assessment: Phase One

Requests for Proposals (RFP) were issued to conduct a Market scan and a Planning Needs assessment. This provided a detailed assessment of sites available in the market that met a set of specific “essential location requirements” and to provide expertise into the conceptualization and documentation of business needs and requirements of Hydro One Networks, ITMC, SEM and Security operations. The main focus was balancing needs and costs against reliability requirements, industry best practices (including Industry participant’s feedback (New York ISO, New England ISO)) and lastly with lessons learned from the current Primary Ontario Grid Control Centre (OGCC). In addition, business requirements were translated into programmed space requirements based on Hydro One’s experience and at the advice of industry experts. A basis of design was developed, capturing the stated requirements and a cost estimate was provided by an external estimator (for building and support infrastructure) and internal Hydro One engineering groups (for Telecommunications and Dual Power and Power System IT).The final basis of design and cost estimate were utilized to initiate the subsequent Detailed Design Phase.

The sizing of the ISOC is predicated on duplicating the OGCC current functions for Backup Control, including parallel use for training simulation and controller / dispatcher training.

The training facilities at the OGCC are currently at capacity. This effectively reduced the size of the ISOC facility by negating the need to program space for training simulation and instead uses technology to use real-time operating space while not active (in backup mode). In the event the OGCC is rendered inoperable or uninhabitable, the new ISOC facility will be able to continue all day to day functions indefinitely with a limited transition period, expected to be one hour or less.

Security Operations sizing was predicated on defined needs of operators, support staff, an investigation room and an Emergency Operations Centre (which will utilize a shared conference rooms when required).

ITMCs Backup Control Centre duplicated the current Primary Centre exclusively, including Control Room space, Data Centre requirements and provisions a back office support compliment to ensure adequate facilities are available for prolonged activation redundancy and assurance of Operations.

SEMs compute needs were documented, forecasted and the incremental capacity was added to the Data Centre white tile space.

Future growth has been accommodated and captured in the detail design however not all space will be built in the initial ISOC build. Data Centre growth has been included up to and including 2035 due to the sensitivity of the equipment and the risk future construction would pose; however the support infrastructure will be purchased on an as needed basis. Future facility expansion will be enabled for future consideration by way of footings and ensuring construction can be achieved without impacting operations (designing connection points etc.) Future extension of the facility, when required will be included in future OEB rate cases.

Detailed Design: Phase Two

At the completion of the Planning Needs Assessment Phase, a Detailed Design phase commenced with the objective to provide all required documentation, designs and costing to tender the end state solution for construction. During this phase, all drawings, facility programing (space definition), IT architecture etc. will be completed, including site procurement (~$3M), Proof of Concept for IT architecture and a final estimation. This information will be packaged and ready for submission for RFP for the construction phase. It is expected to be completed in 2017.

Pending completion of the Detailed Engineering Design and receipt of required approvals, Hydro one will leverage its internal Supply Chain, an Open Market Construction Tender process in two phases.

Phase One: Request for Pre-Qualification ('RFPQ")

Hydro One will seek to pre-qualify a select number of vendors in an open market process, who demonstrate "required competencies" (e.g., proven large project construction experience, defined safety/environmental programs, change control process controls, demonstrated ability to deliver large construction projects on time and to budget, etc.) related to the construction of the ISOC and acceptance of HONI required market-based Terms and Conditions.

Phase Two: Request for Proposal ("RFP")

Hydro One will release to only the pre-qualified vendors a detailed RFP with a complete set of construction documents. Pre-qualified vendors will be required to review the construction documents, offer input with respect to area's which could result in increased costs if not addressed before construction and provide a "fixed" price proposal to a defined scope of work and schedule, linked to a delivery penalty.

Construction Phase: Phase Three

The successful proponent will commence construction and is planned for Q4 2017.

Post Construction award: Hydro One's external designer will monitor on site activities throughout the construction to ensure any issues are addressed early and that required contract quality is delivered. HONI and designates will participate in interactive Bi-weekly onsite construction process meetings to gauge progress to requirements and address concerns which may impact the process.

The ISOC investment has been identified and assessed as a high priority and was subsequently prioritized and planned due to risk and considerations described below.

Site location risks that will continue to be present as there are no viable remedial alternative to the following risks:

- The current site location, and required travel time, requires maintaining an interim backup facility to perform limited functions in the event the OGCC is rendered inoperable and staff have to transition to the BUCC. The ISOC will eliminate this requirement;

- Structure is landlocked, and no expansion potential exists as the facility is surrounded by a Transformer Station;
- Current emergency preparedness risks will remain:
  - In a flight paths (Pearson International Airport);
  - Between two major highways (Hwy 427 & Hwy 401) in the event of hazardous spills;
  - Gas pipe lines located underneath property;
  - Adjacent to transformer station (electrical, fire and asset failure hazard). In 2011, T7 and T8 transformers at Richview both failed catastrophically, resulting in loss of the station and a major fire. This removed the BUCC from use for an extended period of time;
  - Congested area in the event of wide spread emergencies i.e. Civil unrest, blackout, natural disaster, and commute;
  - Adjacent to public storage facilities.
- Facility risks that could render the Hydro One Networks Control Centre or critical equipment unavailable for an extended period of time, eliminating redundancy of critical monitoring and control of the Distribution system include:
  - Flooding in basement, roof and cable entrances, where computer rooms, power rooms, telecom rooms, switchgear, and SONET communications are currently located;
  - Failures of critical support infrastructure including; the fire panel, HVAC, emergency backup power (generator);
  - Inability for expansion and a high cost for retrofit / maintenance activities;
  - Relocation of the equipment located in the basement of the facility is not viable given the space required on the main floor (Computer rooms, telecommunication gear (SONET), Uninterrupted Power Supply units, switchgear etc.;
  - Competing demands for physical space, power, cooling from multiple tenants; and
  - Electric power system is undersized (Station Service).
- ITMC's current BUITMC has documented the following risk and constraints;
  - Located in a shared space with an inability to expand;
  - Requires extensive setup during activation as the facility cannot accommodate a permanent active installation;
  - Cannot accommodate current back office support requirements;
  - Cannot meet security requirements for access control for critical computing equipment;
  - The current HVAC is not adequate for net new occupancy or equipment;

- Lacks the necessary facilities should a prolonged activation be required; and
- ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure.

Hydro One's Security Operations are currently reliant on an external facility that is owned and operated by a third-party creating corporate and regulatory risks given that Hydro One lacks a contingency site that is capable of monitoring the physical security of its sites and assets. Should the facility or 3rd party services no longer be available to Hydro One due to factors outside of Hydro One's control, Hydro One will not be in a position to monitor the real-time security (including door alarms, motion sensors etc.) of its critical sites, creating both a security and public and employee safety risk. Such an occurrence would also lead to a regulatory non-compliance violation with NERC Standards and possible sanctions, financial penalties and risk to corporate reputation.

APPENDIX B – DETAILED ALTERNATIVE COMPARISON

Detailed Alternative Comparison

Alternative	**Description**	**Cost ($)**	**Size (Sq.Ft)**	**Site (Acres)**	**Cost / Sq.Ft**	**OM&A****	**Benefits / Risks**
Alternative One: Status Quo	Maintain existing facilities. (BUCC remediation activities, lease new data hall space and for BUITMC Requirements).	$78M*	18,921	N/A	N/A	N/A	No provision for SOC. BUCC existing location, space, and site constraint risk remains. Significant difficulties for prolonged activation. Includes a leased space for BUITMC, leased Data Centre space for NOD and remedial work to retrofit office space to better accommodate prolonged activation.
Alternative Two	Build NOD BUCC and Data Centre.	$104.8M*	95,420	10+	$1,098	$3.72M	Site, SONET, Dual Power and critical support infrastructure included.
Alternative Three	Build ISOC as BUCC, BUITMC with back office and Data Centre.	$124.7M*	99,716	16.41	$1,251	$4.0M	This includes the preferred site and all critical support infrastructures including but not limited to: SONET, Dual Power, redundant generation, UPS, cooling, shared office and common space. This excludes SOC from inclusion.

Alternative	Description	Cost ($)	Size (Sq.Ft)	Site (Acres)	Cost / Sq.Ft	OM&A**	Benefits / Risks
Alternative Four	Acquire an existing facility for BUCC and BUITMC and integrated Data Centre	Not available. Building specific market scan by Andrew Thompson and Associates (ATA) indicated no suitable site for consideration at time of assessment. Hydro One owned sites were reviewed internally; however also found that no suitable site or facility existed.					
Alternative Five	Build Primary NOD Control Centre, primary SOC, and BUITMC.	$141.9M*	126,200	16.41	$1124	$4.47M	This option assumes that the existing OGCC staff would be moved to the new ISOC and the current OGCC used a Backup. Additional compute / system investment required which is not included in total cost.
Alternative Six	Initiate Build of ISOC with future dual operating capabilities.	$138.4M*	126,200	16.41	$1,096	$4.47M	Provides a NOD BUCC, BUITMC, and Primary SOC including shared integrated Data Centre, and back office support. Current lifecycles for critical applications respected, alleviating addition IT requirements to enable Primary operability. Dual Primary enabled for future implementation.
Ontario Grid Control Centre (data for comparison purposes)		$144.9M	68,000	9.25	$2,131	N/A	Presented in 2016 dollars (originally $118M investment in 2003) Provided for comparison.

*The Distribution portion of this total is 50.07% of the total cost.

**The OM&A cost estimates are the full total cost, and these have not been adjusted to show the distribution portion only.

Data Centre Construction vs. Leased Data Centre

In addition to the above alternatives, a comparison between the option of construction versus a comparable colocation or leased data centre option was conducted by engineering firm Morrison Hershfield, to ensure the most cost effective means of providing needed Data Centre space. This is the largest cost consideration in the overall project total. This assessment was based on a 15 year term based on market prices in the Toronto area. The Toronto area was utilized for this study as it provided a much larger pool of lease options with the required reliability / Tier level standards. The results are shown below which indicated that the co-location/lease option ($122.1M), based on the current design criteria, far exceed the cost of the build option ($73.2M) ($30M in Capital + Incremental annual OMA at $2.5M escalated at 2% per year for 15 years, $43.2M).

	IT/POWER MRC*	**Annual Cost of Rent**
Year 1	$ 341,144.00	$ 4,093,728.00
Year 2	$ 372,529.25	$ 4,470,350.98
Year 3	$ 406,801.94	$ 4,881,623.27
Year 4	$ 444,227.72	$ 5,330,732.61
Year 5	$ 529,725.56	$ 6,356,706.73
Year 6	$ 529,725.56	$ 6,356,706.73
Year 7	$ 578,460.31	$ 6,941,523.75
Year 8	$ 631,678.66	$ 7,580,143.93
Year 9	$ 689,793.10	$ 8,277,517.17
Year 10	$ 753,254.06	$ 9,039,048.75
Year 11	$ 822,553.44	$ 9,870,641.24
Year 12	$ 898,228.35	$ 10,778,740.23
Year 13	$ 980,865.36	$ 11,770,384.33
Year 14	$ 1,071,104.97	$ 12,853,259.69
Year 15	$ 1,169,646.63	$ 14,035,759.58
	Total 15 Year Spend	$122,101,320.25
*MRC = Monthly Recurring Charges include IT load rent, estimated power charges and PUE of 1.6		

Other factors that affected this consideration are; a) no co-location facility provides NERC certified space which would require additional upfront capital cost in year one, b) many facilities have policies that dictate access, upgrade, expansion and security for the facility without renter input which exposed Hydro Ones critical equipment to further risks.

ISOC Breakdown	Est. Cost	Ft2	$ / ft^2	Report Findings of Morrison Hershfield on Build Comparisons
Building Shell Cost	$23M	120,534	$250	Includes shell and basic Mechanical Electrical Power services. This is considered at the bottom of the range of $250/ft2 -$1000/ft2 for hardened facilities of this type, which equals the cost per square foot for SaskPower's most recent facility design. Variance consisted of EF3 Tornado rate vs. EF4 for SaskPower with less office space and did not have Control Room space. Average generic office space range from $150 - 250/sq. ft. dependent on finish and furnishings.
Data Centre Cost	$30M	11,990*	$2502	SaskPower's estimates cost per sq. ft. for data centre space was $3,000 / sq. ft. and it is MH's conclusion that $2502 is within range of similar facilities. A similar telecom project in 2015 with a similar Tier level as HONI was $2575/sq.f.t.
ISOC Total	$138M**	126,200	$1096	This includes Building Shell, Outdoor Yard and Data Centre.

- **Included support galleries (cooling, power distribution).*
- ***Note: The Distribution portion of this total is 50.07% of the total cost.*

Comparisons to Similar Facilities at Other Utilities

Lastly, NOD reviewed a number of utilities investments in facilities and data centre development projects to ascertain the reasonableness of the ISOC scope as compared to the rest of the industry. Below is a table summarizing these findings; which show the ISOC is in line with the cost per square foot for comparable projects.

Industry Comparators	Description/Name	Cost ($M)	Size (Sq. ft.)	Year Built	Adj. Cost to 2016 $ (CPI)	Cost (2016 $) / Sq. ft.
New York Independent System Operator	NYISO Control Center	$59.4M	64,000	2014	$60.82M	$950
American Electric Power	Transmission Operations center	$57.2M	83,500	2007	$65.92M	$789
ISO-New England	Windsor Backup Control Centre	$50.7M	70,000	2014	$51.91M	$742
Pacific Gas & Electric	Distribution Control Center	$52.0M	37,674	2015	$52.57M	$1,395
	Distribution Control Center	$37.05M	24,000	2014	$37.97M	$1,582
	Distribution Control Center	$46.8M	50,000	2016	$46.8M	$936
First Energy	FirstEnergy Tx Control Centre	$58.5M	70,000	2013	$61.16M	$874
BC Transmission Corporation	System Control Modernization Project	$133M	113,022	2008	$148.07M	$1,310
	System Control Centre (building ONLY)	$40M	64,584	2008	$44.53M	$689
	Backup Control Centre (building ONLY)	$30M	48,438	2008	$33.4M	$690
Average Cost :				-	$60.3M	$996
Distribution Portion of ISOC.		$69.3M	63,188	2016	$69.3M	$1,096
Proposed ISOC Cost Comparison		$138.4M	126,200	2016	$138.4M	$1096

Converted from USD to CDN at an exchange of 1 USD to 1.3CDN

Note: The ISOC is comprised of Distribution, Transmission, ITMC and SOC.

Site Assessment

As the table below shows, sites south of Barrie were higher cost and the sites North of Barrie were considerably less expensive. Orillia, given its relative location compared to the Primary Centre, was optimal given the City size, access, lodging, development and emergency services, including the OPP headquarters. Communities further away were ranked lower due to distance, access to emergency services, development and lodging, winter driving hazards and relative site suitability among other factors.

Ranking	Community	# of Sites	Ave. Cost / Acre
1	City of Orillia	4	$114,935 - $181,200
2	Town of Bradford	3	$346,636
3	Town of Collingwood	3	$135,469
4	Town of Midland	6	$90,000
4	Town of Penetanguishene	3	$87,500
5	Town of Alliston (New Tecumseth)	3	$273,900
6	Town of Newmarket	2	$850,000
7	Town of Orangeville	1	$215,000
8	East Gwilliambury	6	$400,000
9	Angus	1	$80,000
10	Innisfill	0	$ -
11	Schomberg (King Township)	1	$475,000
12	Wasaga	0	$ -

Note: An assessment of internal Hydro One TS sites was reviewed against available acreage and emergency preparedness criteria and was determine that there was no existing Hydro One site that could accommodate the proposed facility. This represented a departure for previous assumptions with impacts of land purchase and support infrastructure that must be extended to the preferred site.

GP-19 Operating - Common Information Technology Infrastructure

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	10.6
Primary Trigger:	Asset Driven		
Secondary Trigger:	Reliability/Performance		

Investment Need:

The Common IT ("Information Technology") infrastructure is the shared IT backbone of Network Operating's critical enterprise systems. It is technically more efficient and maintains a lower total cost of ownership as compared to multiple discrete instances to support specific systems. This translates into less sustainment and total system component purchases. Common IT infrastructure is further defined into sub categories, which include:

- Data storage (devices that retain, retrieve and archive digital computer data "information");
- Compute servers (processors that fetch, decode, execute and write data in response to system processes and application inquiries);
- Computer consoles (microcomputers used by Operating Dispatchers, Operators and Managers to interface with applications);
- Information Technology networks (a series of communication paths interconnecting IT devices); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS.

Each sub category includes hundreds of individual assets, both hardware and software products. IT products have lifecycles for a number of reasons, for example market performance, and technology innovation and development, drive change in products or the product matures and is replaced by functionally richer technology. As new technologies are developed, support and the ability to purchase spares or replacements equivalent to in-serviced assets is more costly and difficult to achieve. Regardless of the reason for change, supporting products beyond their lifecycle poses increased risk to Operations.

If extended support agreements are made available, the costs are typically a minimum of two to three times that of current supported market products, which drives consumption to the latest offering. Furthermore, product replacement parts become scarce and inflated in price and run the risk of non-compatibility with other more current devices. These factors and others make the employment of products beyond their lifecycles untenable. As each device is interdependent and the future replacement technology attributes are almost always unknown, pacing and prioritizing is an ongoing effort. Vendors often announce lifecycle support conclusion dates with minimal notice. The continuous process of assessing device compatibility at its lifecycle conclusion requires careful architectural consideration to ensure system reliability and performance standards are constantly being met.

This investment is comprised of multiple asset groupings, and is required to maintain the viability of the common IT infrastructure for Operating's computer applications such as the Outage Response Management System, Network Outage Management System, Network Management System, and Distribution Management System. (Discrete application infrastructure is not included in this investment). These applications are leveraged by both Distribution and Transmission. However this investment represents the Distribution portion exclusively.

Alternative 1: Status Quo:

This alternative is to maintain status quo: do nothing and continue to use the existing IT infrastructure. As each device represents an important interconnected component of the common infrastructure, not proceeding with these lifecycle replacements could result in the following:

- Hydro One's diminished capacity to serve and respond to customers;
- Regulatory non-compliance with the potential for heavy fines;
- Potential loss of one or more mission critical applications;
- Significant increase in Operating maintenance costs;
- Loss of the original equipment manufacturer/vendor support;
- Increased probability of system failures;
- Inability to recover from system failures;
- Increased vulnerability of cyber terrorist attacks;
- Potential to strand future application upgrades and enhancements; and
- Risk of costly remedial efforts in the event of a failure.

Alternative 2: Maintain Supported IT Infrastructure (Recommended*)*:

Lifecycle management based on industry best practices and vendor support schedules ensures the viable operation of Operating IT infrastructure assets, including the enablement and continued reliability of critical application systems. The dynamic architectural model requires Operating to plan and replace devices with the appropriate current technology and is recommended as the only viable option. This option offers the following benefits:

- Continued compliance with availability and reliability standards;
- Current market product maintenance and support costs;
- Original Equipment Manufacturer ("OEM")/vendor provided updates and software patches;
- OEM/vendor available replacement parts at current market prices;
- System compatible infrastructure devices; and
- Improved ability to recover from random failures.

Through systematic replacement of common IT infrastructure Hydro One Networks can sustain business functions by ensuring the tools and systems used to support Operations are functioning as designed, are fully supported, and ensure any failure can be readily remediated. This provides the assurance to Hydro One customers that IT failures will be minimized and if a failure is experienced it will be returned to service in a timely fashion. This approach maintains Hydro One's commitment to customer satisfaction by ensuring responsiveness through system availability.

Investment Description:

These IT infrastructure investments include the following asset sub categories and are located at both the Ontario Grid Control Centre ("OGCC") and the Back-up Control Centre ("BUCC"). Servers, PCs and disc drive counts are always fluctuating depending on the current state of lifecycle management projects. Lifecycles of the various components are dynamic, and can at times be interdependent, influencing other components. The hardware is generally problem-free, however lifecycle management means keeping it in a supportable state as dictated by the vendor. Disc drives do fail but are replaced under service agreements. All devices would be current to the year they were "lifecycled" and there isn't a single "project" that replaces everything at once in a single year therefore the age distribution will always vary. Lifecycle planning forecasts in each category has leveraged historical trends, however careful consideration regarding the lifecycle replacement and transferability of the infrastructure will be provided as Operating relocates the BUCC into the Integrated System Operations Center beyond 2020 including:

- Data Storage (i.e., storage area network devices “SAN”; achieve data storage backups);
- Compute Servers (i.e., secure file transfer devices; monitoring systems; server operating systems);
- Computer Consoles (i.e., Windows operating systems; peripheral devices);
- IT Networks (i.e., remote access devices; satellite time clocks); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS. Oracle and SQL database applications.

A failure of a single component has the potential to cause cascading impacts including; a failure of a critical application and the business function it supports, removal of system redundancy, or worst case, render the OGCC and/or computer systems unavailable. The resulting impact on work execution and customers could be as follows:

- Cancellation or delay of outages requiring planned field work causing customer or Hydro One work to be delayed, requiring rescheduling, reprioritization and rework;
- Unresponsive distribution outage management and lack of communication with customers and staff posing work delays, safety risks and inability to respond to emergency events (i.e. if failure occurs during Storm event); and
- Backup activation which limits full business function and hinders critical response.

Risk Mitigation:

Replacing end of life infrastructure assets is recommended as “best practice” in order to maintain Network Operating’s current supported, compatible and redundant IT infrastructure and equipment. The ongoing dynamic processes to cost effectively assess, prioritize and stage each product in its respective category must remain in focus by Hydro One’s Power System IT architecture team and supporting management and staff at all times in order to achieve success now and in the future. The driving focus behind these processes is to maintain current reliability and service levels with the continued support of mission critical applications and their function is to serve Hydro One’s customers in the most cost effective manner possible.

Result:

These investments will provide cost conscious ongoing product support and dynamic lifecycle management for all common Operating IT infrastructure assets.

Outcome Summary:

Customer Focus	• Provides continued support to key customer applications such as the Outage Management System supporting emergency storm response, communication, and outage coordination. • Minimizes customer risk and associated impacts of outages of the system.
Operational Effectiveness	• Provides Operating IT infrastructure the required facilities to holistically support mission critical Operations applications, systems and their functions. • Decreases risk of reduced performance, or an inability to meet service levels in the event of a failure.
Public Policy Responsiveness	• Ensures mission critical Operations applications and systems are supported with the current, compatible and supported IT infrastructure to maintain reliability and availability targets and meet regulatory requirements with regards to cyber security, reliability (redundancy), etc.
Financial Performance	• Provides cost effective management of IT lifecycles with current and supported common “shared” IT infrastructure. • Reduce OM&A and negate the need for costly extended support. • Improved asset performance, and greater ability to recover from a failure. A single failure can impose significant costs from the disruption to business function, increased labour cost for emergency break fix needs and other remedial efforts.

Costs:

This group of investments is estimated based on historical cost, subject matter and industry experts input, assessments and will be adjusted for the project scope, local condition and market pricing at the time of the investment.

Controllable cost have been minimized through the continued use and shared costs of common platforms, maximizing space, storage, and networking; maintaining current versions / latest technologies to maintain or reduce OM&A costs; and bundling of work to minimize outages or impacts to Network Operating.

2018 budget postponed into 2019 for SAN project. Other minor reductions to budgets in 2021 and 2022.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.1	2.0	0.8	2.0	3.7	10.6
Operations, Maintenance & Administration Removals	-	-				-
Gross Investment Cost	**2.1**	**2.0**	**0.8**	**2.0**	**3.7**	**10.6**
Less Capital Contributions	-	-				-
Net Investment Cost	**2.1**	**2.0**	**0.8**	**2.0**	**3.7**	**10.6**

**Includes Overhead at current rates.*

GP-20 Network Outage Management System (NOMS) Refresh

Start Date:	Q3 2017	Priority:	High
In-Service Date:	Q4 2019	Plan Period Cost ($M):	2.3
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Reliability -Regulatory		

Investment Need:

The Network Operating Divisions (“NOD”) Network Outage Management System (“NOMS”) is Hydro One’s primary outage planning tool. The associated hardware and software is specific to NOMS and does not include any shared storage in the Common Information Technology infrastructure. As required by the Ontario Energy Board (“OEB”) Distribution System Code (“DSC”) and Hydro One’s Conditions of Service, NOMS provides essential coordination and scheduling of planned outages through integration with enterprise systems and the internal lines of business for reduced customer impact, optimized outage performance and improved communication amongst stakeholders (i.e., Local Distribution Companies, Large Distribution and Transmission customers, Hydro One work groups).

NOMS is an essential tool for planning, scheduling, assessing and executing distribution equipment outages. The viability of the tool is being reviewed and investigated for potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors being considered are availability, sustainment cost, system growth, the availability of new technologies, and compatibility with other critical Operations systems and applications, such as the Equinox Control Room Operations Window (“CROW”), Utility Work Protection Code, Electronic Log, and SAP applications. The system must be supported by the vendor or Original Equipment Manufacturer (OEM) as the risk of system downtime directly affects distribution operations and Hydro One customers.

The investment in a new NOMS tool must also satisfy regulatory requirements such as the OEB DSC Section 4, Operations; specifically Section 4.4.7 which requires a utility to provide as much advance notice as possible for the duration and frequency of a planned outage. This outage tool must also ensure compliance with Hydro One’s Conditions of Service policy, Section H, Outage Notifications Process with customers.

The current version of NOMS was placed in service in 2010 after an application software upgrade to version 2.0 (NOMS V2). The software upgrade did not include a hardware upgrade at that time. The NOMS system consists of application servers, primary database servers, reporting database servers and a backup disaster recovery database server. An investment is now needed to upgrade the NOMS application and hardware to address four inadequacies of the current system that pose operational risks to Hydro One:

- Vendor support has expired and extended support is no longer available on servers running Oracle's 10g software;
- Application and Database servers have reached end of life; and
- The Windows 2003 Operating System used for the NOMS application server is no longer supported and update patches are no longer available.

The results of these operational risks of running an unsupported application will only increase Hydro One's inability to recover outage planning systems in the event of a system failure. The impacts to Hydro One's business in the event of these failures would be loss of outage planning and coordination abilities, higher maintenance costs, failure to efficiently communicate outage planning efforts with stakeholders, and decreased safety for Hydro One employees.

Alternative 1: Status Quo:

The Status Quo alternative would maintain the existing NOMS unsupported software and end of life hardware. This alternative has been rejected for the following reasons:

- Continuing operations with end of life system hardware will increase the likelihood of a NOMS failure;
- Continuing operations on end of life hardware without vendor support will hinder Operations ability to recover systems in the event of a failure;
- Maintaining end of life hardware results in increased maintenance costs and workarounds; and
- The risk of increased frequency and duration of customer outages and reduced distribution system performance.

The risk and impact in the event of a failure of NOMS will be significant given the primary function of NOMS is to plan and coordinate all Hydro One work execution activities. This will have a significant effect on the operation of the Hydro One distribution system and its customers.

Alternative 2: Upgrade NOMS *(*Recommended*)*

This alternative would upgrade both hardware and software for the current NOMS application and address the unsupported software and the operational risks currently faced by Hydro One.

A new application, upgraded servers and operating systems will provide Hydro One with improved outage planning capabilities as part of the version upgrade and the ability to recover systems in the event of a failure that would otherwise not be possible with the Status Quo option. A reliable outage planning tool is a requirement of the OEB's Distribution System Code and Hydro One's Conditions of Service. It is prudent that a full NOMS upgrade is performed to maintain Hydro One's outage and work planning capabilities and to ensure the distribution system reliability and availability.

Investment Description:

Planned investments include a hardware refresh, operating system upgrade and the integration with other enterprise systems such as the Electronic Log, Utility Work Protection Code, SAP and the Outage Grouping and Assessment System Tool. These are either a part of the version upgrade or existing stand-alone systems that when integrated will enhance the flow and assimilation of information that will enhance the outage planning and reporting processes.

Risk Mitigation:

IT Infrastructure investments are complex and dependent on multiple technology factors including: application software, server capacity, physical constraints (i.e., cooling capacities), hardware compatibility and vendor support terms. Given these complexities, a development phase is being conducted as a part of the full NOMS upgrade to more effectively determine project costs and manage the risks and requirements associated with the project implementation. Additionally, an assessment of the enterprise systems; Electronic Log, Utility Work Protection Code, SAP, and the Outage Grouping tool will be performed to ensure value creation when merging the systems with NOMS.

Result:

This investment will result in the following accomplishments:

1. Increased stability of the NOMS system with upgraded hardware and software that has vendor support;
2. Reduced risk of a NOMS system failure;
3. Ensured regulatory compliance with the OEB Distribution System Code, IESO Market Rules and adherence to Hydro One's Conditions of Service;
4. Assessment and integration of internal and enterprise systems; and
5. Improved operational efficiencies and outage performance gained through the integration of enterprise systems and new technologies.

Outcome Summary:

Customer Focus	• Mitigate Customer impacts by providing as much advance notice as possible for the duration and frequency of a planned outage.
Operational Effectiveness	• Ensure reliability and availability of NOMS to ensure scheduling, coordinating and planning of Hydro One Distribution and Transmission System Outages. • Ensure operational efficiencies and process changes are fully leveraged by improving current workflow, coordination, grouping and execution of outage planning activities.
Public Policy Responsiveness	• Deliver outage management service obligations related to OEB Distribution System Code, Section 4, Operations, and IESO Market Rules part 7.3 Outage Management. • Maintain compliance with Hydro One's Conditions of Service.
Financial Performance	• Reduce extended support and maintenance costs associated with maintaining the system to mitigate failures.

Costs:

Costs are being controlled via an initial development phase, which will finalize scope, system architecture, and an execution strategy prior to full execution of this investment. In addition, several vendor products will be reviewed and assessed to determine which are the most cost effective and provide the most value. Lastly, through a full capital replacement, testing and commissioning activities will be completed simultaneously. This will negate the need for independent system component testing and allow the more efficient use of resources.

Spend was deferred due to delays in project start.**($ Millions)**	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs********
Capital* and Minor Fixed Assets	0.3	2.0	-	-	-	2.3	2.3
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	0.3	2.0	-	-	-	2.3	2.3
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**0.3**	**2.0**	**-**	**-**	**-**	**2.3**	**2.3**

**Includes overhead at current rates.*

*** Total Project includes amounts spent prior to 2018.*

GP-23 Integrated Voice Communications and Telephony Refresh

Start Date:	Q2 2021	**Priority:**	Demand
In-Service Date:	Q3 2023	**Plan Period Cost ($M):**	5.1
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Regulatory		

Investment Need:

The Integrated Voice Communications and Telephony System (“IVCT”) is a mission critical system that provides voice communication management between the control centre, the IESO, Hydro One field staff, connected customers, and emergency services. The IVCT system provides integrated access and intelligent call routing via multiple communication methods incorporating multiple technologies to adequately manage the hundreds of control room calls each day. The IVCT system runs on various software, operating system, and hardware with vendor support, software patching and service lifecycles. Based on the current vendor support schedules and hardware lifecycles the IVCT system will require replacement in 2021 to maintain support and reliability of the system and the ability to recover in the event that a failure is experienced. The IVCT system allows Hydro One to meet various compliance regulations (Distribution System Code, NERC, Market Rules) that require redundant voice communications, and emergency communications that ensure constant communications paths.

The loss of voice communication between the Control Room (the primary users of the IVCT system), Hydro One customers and field staff, will result in the cancellation of planned outages and work activities until communication has been re-established. Without effective communication, there is a heightened risk to worker and customer safety (cannot dispatch emergency services or field staff), and a lack of situational awareness of local activities or external system events. This can have dire impacts on the Distribution System.

Alternative 1: Status Quo

This alternative maintains the existing IVCT system at end of life. This will expose Hydro One to reliability and sustainment risk as the current IVCT system will no longer be supported by the vendor. In addition, the ability to recover from a system failure will be negatively impacted and the maintenance cost for extended repairs or replacement components (old technology at this time) will be higher and more difficult to procure.

The IVCT system is mission critical, as it handles all calls coming into and out of the Ontario Grid Control Centre (“OGCC”) and Back Up Control Centre (“BUCC”) control rooms. This includes communication with field staff, customers, and the IESO among others. A failure of the system would eliminate control room communication efforts, therefore impeding the operational effectiveness of the OGCC.

Alternative 2: “Off the Shelf” IP Phone

This alternative proposes the current system be replaced with generic IP phones utilized by back office staff, after the existing IVCT system reaches end of life. The generic IP phones do not have the same call handling functionalities or rolodex of frequent calls capabilities requiring additional tools and processes to ensure that control room staff efficiency is maintained and not subject to additional effort to complete the same tasks. These processes, which must be recreated for this Alternative, are more error prone and can impact employee and customer safety. Furthermore, the generic IP phones do not have any call recording capabilities to meet NERC compliance requirements. Lastly, the IVCT system includes the OGCC Interactive Voice Response (“IVR”) system which is used to direct incoming calls to the appropriate OGCC department and sort calls into queue(s) for processing. To ensure normal work flow can continue, integration with the IVR system is needed. Due to the aforementioned issues and concerns, and the inability to provide needed functionality, and integration with key elements, such as IVR, this alternative has been rejected from further consideration.

Alternative 3: IVCT System Refresh Project (Recommended)

It is recommended that Hydro One proceeds with the IVCT system replacement to ensure system reliability and sustainability. This alternative provisions the necessary replacement of the IVCT system in 2021, with a “like for like” system, taking advantage of productivity enhancements, and leveraging newer technologies when the existing IVCT system has reached end of life. This will maintain operational effectiveness and reliability of the control room by maintaining the communication channels utilized daily. This will also mitigate risk of control room downtime, work execution, planned outage cancellations, and the resulting impacts on Hydro One customers that these incidents cause. Control room staff utilizes the IVCT system when coordinating storm restoration, planned system maintenance outages, fulfilling IESO notification obligations, managing helicopter services, and, most importantly, emergency response assistance for field staff and Hydro One customers.

Investment Description:

Network Operating Division operates two Grid Control Centres. The IVCT system is used on a 24/7 basis at both control centres (OGCC & BUCC) and the Operating Planning department. The IVCT system is mission critical and provides effective voice communication management from both control centres with the IESO, interconnected utilities, Hydro One customers, emergency services and field staff. Due to the critical nature of the IVCT system, and the impact of a failure on Hydro One's work execution, customer outages, responsiveness, and inability to effectively dispatch for emergencies, this system is planned to be replaced based on recommended lifecycle schedules. The failure of the IVCT system would severely impair Hydro One's ability to monitor and mitigate system events.

This investment will replace or upgrade the application software, and associated hardware (dedicated servers) at the OGCC and BUCC (which is ultimately planned to be relocated to the Integrated System Operating Centre ("ISOC")).

This investment is scheduled based on historical IT life cycles for previous instalments of the IVCT system with consideration of software, operating system, and server hardware lifecycles. An asset condition assessment review may be made closer to the investment start date to determine how best to proceed.

Risk Mitigation:

To reduce project execution risk, a pilot IVCT system will be designed and tested prior to full deployment, including parallel system use prior to final cutover. Furthermore, an experienced system integrator vendor, with expertise in deploying similar IVCT systems, will be retained to oversee the project.

Productivity enhancements and new technologies, such as automated voice-to-text capabilities, will be individually evaluated through a cost-benefit analysis closer to the project start date to ensure value for the required investment. Timing of this activity is required prior to commencement, as technologies and improved functionality today may differ significantly in 2020/2021.

Result:

This investment will ensure reliability of the IVCT system and promote productivity in the control room while meeting all regulatory requirements. The IVCT is set with user friendly touchscreen interface, quick dial functionalities, and a customized Rolodex contact database to help controllers do their job more accurately, more efficiently, and faster. The IVCT helps Hydro One operations meets its obligations under the OEB Distribution System Code, IESO Market Rules, and NERC (see Public Policy Responsiveness section below for full details).

Outcome Summary:

Customer Focus	• Support customer reliability by maintaining low call handling time and fast storm restoration response. • Keep customers informed of outage status using Autodialer functions and therefore improving customer satisfaction.
Operational Effectiveness	• Allows Hydro One control room staff to more efficiently co-ordinate storm restoration, protection maintenance work, system events with field staff, other LDC, and end use customers. • Ensure effective response and minimizing outage times.
Public Policy Responsiveness	• Allow Hydro One to meet obligations under OEB Distribution System Code (Section 4) regarding operations requirements. • Allow Hydro One to meet obligations under IESO Market Rules (Part 7.3) regarding outage management procedures. • Allow Hydro One to meet event reporting and investigation obligations as specified in NERC standard EOP-004, and COM.
Financial Performance	• Effective communications ensure the quickest dispatch for faster restoration times which translates into less hours spent by field crews during unscheduled events, reducing field costs.

Costs:

This is a reoccurring investment and the budget cost has been determined based on estimates by the Power System Information Technology ("PSIT") division utilizing historical IVCT investments. Based on lessons learnt from previous IVCT projects, this proposed budget takes into consideration all relevant costs (including license fees, changes to interest/overhead charges) which may not be initially obvious. The ongoing sustainment upkeep cost of the new IVCT system will have to be submitted by prospective vendors as part of their solution proposal. The OM&A cost for the current IVCT system is approximately $1 million annually. Hydro One will strive for the new IVCT system to have OM&A cost equivalent to the current system or less. Final costs of the project are influenced by the change in technologies and costs associated with the infrastructure supporting it, including market pricing at that time. Technological uncertainties and obsolescence are always a challenge for capital projects that are expected to start four to five years later. Hydro One is continuously monitoring technological developments and industry best practices to ensure the most cost effective solution.

Given lessons learned from the last upgrade, funding was reshuffled and smoothed across three years to accommodate a longer project schedule.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	-	-	-	2.0	3.2	5.1	6.3
Operations, Maintenance & Administration Removals	-	-	-	-	-	-	-
Gross Investment Cost	-	-	-	2.0	3.2	5.1	6.3
Less Capital Contributions	-	-	-	-	-	-	-
Net Investment Cost	**-**	**-**	**-**	**2.0**	**3.2**	**5.1**	**6.3**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent after 2022.*

GP-35 Asset Analytics Risk Factor

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	3.3
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

Asset Analytics (AA) is a major investment planning decision support toolset. It is an SAP-powered application which represents an enterprise asset risk factor program that consistently measures and models Transmission and Distribution asset risks. The Business has been using the AA program since 2013.

The existing AA program collects asset related information from SAP and other non-SAP interfaces. The data received is used to calculate “Controls” such as Supporting Factors which in turn contribute to the calculation of Risk Factor scores that are used to assess the assets. These controls assist planners identify assets whose status indicates that replacement and/or repair is warranted.

Asset Managers leverage AA output information to make decisions regarding power delivery reliability and supply continuity. Consequently they initiate plans for future capital investments and work programs to improve delivery reliability, customer satisfaction and shareholder value.

Since existing calculations have remained unchanged since the initial deployment of AA, it has been identified by the Asset Managers that current Controls require remediation and extension to improve the quality of the asset risk model, and the granularity for decision making. Specifically required Risk Factor upgrades cover:

a. Adding two new Risk Factors, (Obsolescence and Health, Safety and Environment); and
b. Modifying current Risk Factors with improved data feeds, calculations and reporting.

Alternative 1: Maintaining the Status Quo

- With status quo option, Hydro One can continue to use the AA program with its existing features. This is not to Hydro One's advantage since some of the controls of the existing system require remediation and extension in order to be able to fully realize intended business value and operational efficiencies.

Alternative 2 (Recommended): Implement AA Risk Factor Upgrades

In addition to leveraging the capabilities of the existing AA program, this alternative will lead to realizing the needed business values and operational efficiencies including:

a. Adding two new Risk Factors: The Health, Safety and Environment Risk Factor will contribute to further improving decision data and reducing exposure to employee, public and environmental safety, negative regulatory and media attention. The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment; and
b. Modifying current Risk Factors: This will contribute to improving the quality of the asset risk model as well as the granularity for decision making.

Investment Description:

This investment is to upgrade the Asset Analytics Risk Factors which are used by Investment Planners to support asset maintenance programs and future capital investments planning. The high level scope of the project is expected to be as follows:

a) Add two new Risk Factors. These include:
    - Health, Safety & Environment (HS&E) will incorporate key initiatives around health or environment concerns, such as PCB levels in the insulating oil. Legislation has been enacted that PCB needs to be within certain levels to limit exposure of individuals to the health risk and this investment will support that initiative.
    - Obsolescence will assist with planning the asset useful service life including identification of corrective measure related to equipment defects and availability of spare parts.

b) Modify current Risk Factors with improved calculations and reporting. These include:
- Adding additional Supporting Factors_to algorithms or data feeds to improve the granularity and sensitivity of the Risk Factor scores leading to improved prioritization of assets for work and replacements.
- Adjusting the weighting of Supporting Factors in the algorithms to improve Risk Factor score sensitivity. If an algorithm was not correctly_designed and implemented the first time, correcting it improves the confidence in the Risk Factor scores.

c) Train end users on the operation of the changes in AA.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The Asset Analytics (AA) Tool a complex application and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Asset Management – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. In addition, follow up workshops will be conducted at appropriate project stage gates.

Result:

The delivery of the AA Risk Factor Upgrade project will lead to refining the existing risk factor calculations and will help improve quality of investment planning supporting data and in turn the decision quality and results.

The addition of the new Health Safety & Environmental Risk Factor will further improve this decision data and reduce risks to employee, public and environmental safety, and in turn investor confidence and negative regulatory and media attention.

The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing asset risk data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Upgrades to the AA Risk Factors will ultimately help improve electrical power delivery reliability, supply continuity, data quality, system efficiency and asset investment decision making.
Public Policy Responsiveness	• The outputs from the AA system feed into several information and reports frequently used for regulatory agency reporting (OEB, NERC, IESO, and NEB), government agency reporting (Min of Energy) and customer queries.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on the historical business case estimates of previous AA implementations. Detailed business requirements will be completed during the design phase of the project in order to determine final project costs. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One investment review and approval processes.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

Investment was advanced in recognition of its importance to planning.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	**1.3**	**-**	2.1	**-**	**-**	3.3
Less Removals	**-**	**-**		**-**	**-**	
Gross Investment Cost	**1.3**	**-**	**2.1**	**-**	**-**	**3.3**
Less Capital Contributions	**-**	**-**	-	**-**	**-**	
Net Investment Cost	**1.3**	**-**	**2.1**	**-**	**-**	**3.3**

** Overheads included at current rates.*

GP-36 Source-to-Order Transformation

Start Date:	Q2 2016	**Priority:**	High
In-Service Date:	Q2 2018	**Plan Period Cost ($M):**	1.4
Primary Trigger:	Enhancement		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One's existing Source-to-Order (S2O) process entails significant degree of manual and paper-based activities, which lead to longer-than-desired procurement cycle times and lost savings. In addition, the enabling SAP technology currently in use is outdated, has limited capabilities and approaching end-of-support time horizon.

Hydro One's Supply Chain is embarking on an overall business transformation journey, aimed at achieving its operating cost management efficiencies and service improvement targets. This S2O Transformation Project is aimed at delivering the technology enablers to support such business transformation, through the implementation of the SAP Ariba and Fieldglass systems.

Alternative 1: Status Quo

Status Quo is not considered as it will result in Hydro One continuing to operate an outdated technology platform that will not be able to achieve and maintain the projected full potential of productivity. In addition, any negotiated savings initiatives will continue to be at risk of non-realization due to existing off-contract spending practices across Hydro One, which are hard to track and control.

Alternative 2: Implement SAP Ariba and Fieldglass Systems (Recommended)

This alternative involves the implementation of the SAP Ariba and Fieldglass systems to enable re-engineering of Hydro One's source-to-order business processes to industry best practices. Four key areas of focus are following: (a) Sourcing & Contract Management; (b) Services & Contingent Staff Procurement; (c) Goods Requisition & Procurement; and (d) Category Management. This alternative will enable realization of benefits the following primary value levers: (a) Sourcing Savings; (b) Spend Compliance; (c) Process Efficiencies; and (d) IT Infrastructure Efficiencies.

Investment Description:

This alternative involves the implementation of the SAP Ariba and Fieldglass systems to enable re-engineering of Hydro One's source-to-order business processes to industry best practices, focusing on the following the following:

- Sourcing & Contract Management - The current SAP-based sourcing platform has limited functionality and will receive limited support from SAP going forward. No central repository exists, resulting in disparate systems and paper filing cabinets being used for managing contracts, making quick search and retrieval of purchasing documents extremely difficult. Implementation of SAP Ariba's Collaborative Sourcing tool will address this need.

- Services & Contingent Staff Procurement - Current procurement of services and staff augmentation process is inefficient, lengthy, manual intensive and lacks transparency. SAP Fieldglass will be leveraged to provide greater control over Hydro One's external workforce and introduce new tools to manage the Statement of Work engagements.

- Enhanced Requisitioning and Procurement - Requisitioning of goods and services is currently cumbersome and often difficult for users to find what they need. This investment will include the tools to support a streamlined and efficient requisitioning/procurement process resulting in shorter cycle-times, less error and positive user-experience through an Amazon.com-like shopping facility.

- Category Management Transformation - Supply Chain is embarking on a parallel Category Management Transformation initiative, which will have to be closely aligned with the Technology Transformation to ensure that the new Sourcing Strategy is well integrated with the processes, toolsets and templates being implemented.

Risk Mitigation:

The following are the key risks that the project plans to address and manage:

Change Management

There is a significant change impact in following areas – Hydro One Supply Chain, Inergi Supply Chain, the LOB Requisitioning community and the external vendors. To mitigate the risk, Hydro One Change Management is engaged early on and a robust change program will be part of the scope of the project. During the selection of the

Systems Integrator, change management program was highlighted as a critical requirement and appropriate project oversight will be in place to ensure appropriate training and change documentation is delivered.

Result:

Below are the key benefits for this investment:

- **Sourcing Cost Avoidance –** Unit pricing in categories where eAuctions are utilized can be expected. Further tactical savings will be achieved through increased competition via the automated spot quote process.

- **Spend Compliance –** Increased compliance as a result of the requirement to use preferred suppliers and contracts will drive avoidance of off-contract spend. Service processing through Fieldglass will improve service invoice accuracy, increase automation and reduce overpayment.

- **Supply Chain Organization Efficiencies –** Overall reduction in manual processes throughout the entire S2O lifecycle and promoting an increased self-service requisition model with less reliance on manual touch-points throughout the process.

- **IT Infrastructure Efficiencies** - The proposed solutions are cloud-based. As such, the existing physical requirements in terms of maintenance, hardware and upgrades are significantly reduced. Software upgrades will be done automatically quarterly with testing effort due to the limited customization and local configuration.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Process efficiencies, shorter cycle-times, reduced error and positive user-experience.
Public Policy Responsiveness	
Financial Performance	• Improved financial performance through cost avoidance as identified above.

Costs:

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.4	0.0	0.0	0.0	0.0	1.4	6.4
Less Removals	-	-	-	-	-	-	0.0
Gross Investment Cost	1.4	0.0	0.0	0.0	0.0	1.4	
Less Capital Contributions	-	-	-	-	-	-	0.0
Net Investment Cost	**1.4**	**0.0**	**0.0**	**0.0**	**0.0**	**1.4**	**6.4**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-37 Engineering Drawing Management

Start Date:	Q2 2016	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	2.7
Primary Trigger:	Enhancement		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

The existing processes and applications used to manage engineering drawings involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

This investment will increase productivity and efficiency in the areas of engineering design, project management and construction, to a level that is NERC compliant (i.e. <30 days). By transforming the methods and engineering design processes to modern and comprehensive solutions, Hydro One can more effectively deliver engineering projects. This is achieved through establishing better practices, leveraging new technologies, implementing best of breed in engineering design and data management, and by creating repeatable templates based on accepted standards and with intelligent integration. This project will reduce effort and deliver engineering drawings faster that cascades efficiency from conception to build. This increase in productivity will help in meeting our other strategic objectives and in particular, to achieving value for our customers and our shareholders. This investment will be used to consolidate applications that are redundant, replace applications with more effective technologies and streamline delivery processes that today are driven by legacy processes.

Alternative 1: Status Quo

This alternative was considered and rejected as a result of the following:

- significant, achievable productivity gains would not be realized;
- would continue to rely on manual and untimely paper processes; and
- the existing platform is no longer supported beyond April 2018 and is incompatible with Windows 10 which has a scheduled in-service date of 2018. This option would result in stranding a large user base from moving to a new corporate operating system as well would risk using unsupported software.

Alternative 2: Migrate to a single company platform (Autodesk's suite of products)

A complete Autodesk solution (an alternative document management system) is not currently available, creating a timing risk, and functionality remains uncertain. Autodesk proposed to reassess once the toolset is upgraded in 2018, however this does not mitigate current risks and uncertainties remain. Therefore, this alternative was rejected.

Alternative 3: Engineering Drawing Management (Recommended)

This alternative involves the implementation of new technologies to allow Hydro One to automate and streamline the vast majority of its manual drawing processes, the opportunity to forgo current sustainment costs as well as being Windows 10 compatible. In addition, current users are already familiar with the technology, upgrading within the family suite will facilitate deployment and minimize work disruptions.

This alternative will result in both quantitative and qualitative benefits.

Investment Description:

Through a competitive procurement process in 2017, the decision to standardize using Meridian's vault capabilities was made and a systems integrator was retained to help configure and deploy the solution.

This investment will streamline Hydro One drawing management processes and deliver an enhanced, integrated system, achieving productivity benefits within Engineering.

Risk Mitigation:

The new system will result in changes to underlying engineering work processes affecting 1,500 users, which could impact productivity in the short term. The project team will engage with Hydro One's change management team to develop a robust program that will ensure sufficient engagement, training and communication throughout the project.

Result:

This project will leverage new technologies to allow Hydro One to automate and streamline the vast majority of its manual drawing processes, the opportunity to forgo current sustainment costs as well as being Windows 10 compatible.

This project will also provide direct access and assignment of awarded work to 3rd party organizations, and eliminate the need to print and distribute drawings for approval and records purposes. Reducing manual steps and providing data validation at time of entry, will result in higher data quality and increased staff productivity.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Improve work processes by eliminating / automating as much of the manual & paper handling work activities as possible.
Public Policy Responsiveness	
Financial Performance	• Reduce one-time costs via decommissioning HOPP2 software. • Reduction of plotting hardcopy drawings. • Reduction of external engineering costs from automation of drawing transmittal

Costs:

The following costs are based on planned estimates.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.4	0.4	0.4	0.3	0.3	2.7	3.6
Less Removals	-	-	-	-	-	-	0.0
Gross Investment Cost	1.4	0.4	0.4	0.3	0.3	2.7	
Less Capital Contributions	-	-	-	-	-	-	0.0
Net Investment Cost	**1.4**	**0.4**	**0.4**	**0.3**	**0.3**	**2.7**	**3.6**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-38 SEM Consolidation

Start Date:	Q2 2017	Priority: High	
In-Service Date:	Multiple	Plan Period Cost ($M):	2.4
Primary Trigger:	Reliability		
Secondary Trigger:	Public Policy Responsiveness		

Investment Need:

Hydro One currently has two separate and distinct environments for monitoring and alerting on Security Events; one managed by Power Systems IT for any assets under their responsibility (such as stations), and the other managed by Hydro One Telecom on behalf of Hydro One Networks Inc. (HONI) Security Operations which monitors Hydro One Corporate systems. This investment will consolidate the two environments to enable centralized monitoring improving security awareness, knowledge and insight into security events happening across Hydro One and ensure NERC compliance.

The existing environments provide security monitoring primarily for TX assets. The consolidated environment will start to incorporate applicable DX assets. With this, the consolidated 24 x 7 security monitoring is designated as a common capital investment.

Alternative 1: Status Quo - Do Not implement a consolidated Security Monitoring application

Not recommended as current environment does not provide real-time visibility to the entire IT infrastructure (Power Systems IT and Corporate) for threat detection, putting the NERC assets at risk.

Alternative 2: Keep the two environments and consolidate monitoring resources

This strategy would not reduce the risk to Hydro One as the two environments do not have the ability to correlate security events across Power Systems IT and Corporate network. A security event could appear as a minor incident in one environment, however if that same event was occurring in both Power System IT and Corporate environment it would pose a significant threat. As such, this alternative was eliminated.

Alternative 3: Full Implementation (Recommended)

The recommended alternative is to implement a consolidated security monitoring with centralized 24 x7 monitoring.

Investment Description:

This investment is to implement a security information and event management system to provide real-time visibility to events that help detect and respond to cyber security threats across Hydro One networks. Security events, trends and patterns will be analyzed and investigated by a centralized outsourced team providing 24 x 7 monitoring and alerting to meet regulatory requirements. A security incident that results in risk or damage to assets or operations, or suspicious trends and patterns are reported to HONI Security Operations team.

Risk Mitigation:

There are no significant risks identified to the completion of this investment.

Result:

This investment will result in regulatory compliance with applicable NERC CIP standards, while ensuring grid reliability and resiliency against cyber security threats to Hydro One's Control Centers.

Benefits include:

- Proactive security monitoring, detection and response across Hydro One's network
- 24 x 7 security event monitoring in compliance with NERC
- Greater adherence to NERC regulatory compliance.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Consolidating the environments provides real-time monitoring across Hydro One.
Public Policy Responsiveness	• Compliance with policy guidelines set by NERC/CIP
Financial Performance	

Costs

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.3	0.0	0.2	0.7	0.2	2.4	3.5
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	1.3	0.0	0.2	0.7	0.2	0.0	3.5
Less Capital Contributions	-	-	-	-	-	-	0.0
Net Investment Cost	**1.3**	**0.0**	**0.2**	**0.7**	**0.2**	**2.4**	**3.5**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-39 Enterprise Analytics

Start Date:	Q12019	**Priority:**	Medium
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.4
Primary Trigger:	Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

Hydro One is consolidating its reporting and analytical tools onto a common platform that will support Tx/Dx system performance, customer service, reliability and work performance.

Today Hydro One uses disparate tools that require large, stand-alone data sets with multiple integration points. In the future Hydro One will be using a single common repository and data set which will enable the enterprise to accurately and efficiently consolidate and process the data required to enable proper analysis.

Alternative 1: Maintaining the Status Quo

Maintaining the status quo leads to continued difficulty in achieving maturity in the ways information processing and reporting activities are carried out. Hydro One has a host of applications ranging from spread sheets to SAP and most of which are not standardized nor integrated. As a result, the affected LOBs will continue to lack access to proper detailed analysis applications and supported processes.

Alternative 2 *(Recommended)*: Common analytical framework for reliability and business analytics

The benefits associated with this solution lie in the consolidation of multiple LOB data and reporting requirements into a common delivery framework of data consolidation, aggregation and analytics resulting in improved reliability reporting and customer service.

Specific benefits include:

- A single source of truth, data/information which will then be aggregated to appropriate levels to meet different organizational requirements;

- Migration from desktop/home grown application/databases to an integrated enterprise application/solution;
- Improved data quality gained via an integration of multiple source systems into a "single source of truth" and the elimination of the current need to query multiple disparate source data systems;
- Enhanced data mining capability that enables ad-hoc query request capability;
- Facilitating a cascading framework of reports that will enable coordination between the LOBs around identified issues and action plans.

Investment Description:

This project is to implement the Hydro One consolidated analytics solution, and implementation of appropriate analytics to facilitate reliability reporting. The project will also involve the migration of historic data, and leverage a number of enterprise data sources, capabilities, reporting and other tools. The recommended execution plan will take approximately 18 months to complete both the distribution and transmission reliability components by the fourth quarter of 2020.

Risk Mitigation:

Resources and Competing Priorities:

Hydro One has many demands on its IT infrastructure, SAP and Enterprise Architecture resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities.

Data Quality:

Early engagement and contact with the teams contributing to identifying data entities, data gathering, data conversion and data migration has to take place to monitor their progress and alignment to the Data Lake Delivery plan.

Solution Complexity:

The new tools will incorporate numerous, and in some cases complex data extraction and validation processes to derive the reliability and other Business performance metrics. A concern is that the build may result in components of such complexity as to make testing and error detection difficult. The project team has to engage with the Vendor to build the new tools such that testing of each and isolation of the source of issues is readily possible. The plan will include provision for this and will address both time and cost implications.

Result:

Improved data quality and reduced complexity to support the analytical and reporting needs of the enterprise.

Outcome Summary:

Customer Focus	• Improve customer service by providing data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability and customer satisfaction.
Operational Effectiveness	• Improved efficiency and accuracy of system reliability performance reporting and coordination.
Public Policy Responsiveness	• The Data Lake tools will support outputs and queries frequently needed for regulatory agency reporting (OEB & NERC & IESO & NEB), government agency reporting (Min of Energy), customer queries, and industry associations (CEA & NATF).
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the following application components and processes: Data Collection, Data Aggregation, Calculations and Reporting.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.0	1.7	0.7	0.0	0.0	2.4
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	0.0	1.7	0.0	0.0	0.0	2.4
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**1.7**	**0.7**	**0.0**	**0.0**	**2.4**

Includes Overheads at Current Rates

GP-40 Information Rights Management

Start Date:	Q2 2016	Priority:	High
In-Service Date:	Multiple	Plan Period Cost ($M):	2.7
Primary Trigger:	Reliability		
Secondary Trigger:	Public Policy Responsiveness		

Investment Need:

Information Rights Management is a technique used by organizations to reduce the corporate risk of intentional or unintentional disclosure of private/confidential information to internal or external users by managing, controlling and securing content to authorized personal.

This is achieved through Role-based access control (RBAC). RBAC is a method of regulating access to applications, systems or network based on the roles of individual users according to job competency, authority, and responsibility within an enterprise.

Role based access control manages Segregation of Duty controls to ensure no individual has the authority to execute two or more conflicting sensitive transactions with the potential to impact financial statements in accordance with C-SOX (previously Bill 198). Access is limited to specific tasks such as the ability to view, create, modify or approve.

Alternative 1: Status Quo - Do Not implement an Information Rights Management Solution

Not proceeding with this investment would result in increased security and reputational risk to Hydro One. Critical data would not be protected within the organization, and more importantly, when it leaves the organization.

Alternative 2: SAP Role cleanup

Not proceeding with this option. SAP role clean up primarily entails the removal of unnecessary access however does not fully address determining who should have access to sensitive functions and data, redesign of privilege access to reduce segregation of duties conflicts or applying the mitigating controls.

Alternative 3: Full Implementation (Recommended)

This will ensure that the data is protected by redesign of roles implementing best practices, controlling and monitoring access and applying the governance to maintain regulatory compliance. Given the high level of awareness to privacy and confidentiality by Hydro One's businesses and customers, this alternative was evaluated and deemed a necessity for protecting Hydro One data in a modern business environment. This is the preferred alternative.

Investment Description:

This investment is to implement role based access control focusing on SAP (ECC and CRM) role clean up eliminating duplicate and redundant roles, redesign of key roles, assess job function and required access, restrict sensitive access, apply segregation of duties controls and enable automated provisioning, continuous monitoring and governance to meet compliance requirements.

Streamline role assignment processes for on/off boarding, rotations, transfers and inter-company movement to ensure an employee has the right access at the right time based on job function and role.

Risk Mitigation:

Information Rights Management manages and controls access to systems, applications and networks based on job function, granting the appropriate level of access reducing the risk of segregation of duties conflict, unauthorized access and penalties due to non-compliance with NERC and C-SOX.

Result:

- Compliance with external policies such as NERC and C-SOX, which mandate Hydro One to protect critical data. Information Rights Management is a key part in this protection.
- Enforce corporate policies that govern the use and dissemination of content within the company (as cited in, "Information Classification and Handling Standard - SP 1324 R2" Policy).

- Reduced litigation risk through the prevention of sensitive data from being viewed by the wrong users or even leaving the organization unprotected and then easily passed on to other external parties.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Monitoring and control of access and simplified role access based on job function
Public Policy Responsiveness	• Compliance with policy guidelines set by NERC and C-SOX
Financial Performance	

Costs

The following costs are based on planned estimates.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	0.8	0.0	1.2	0.7	0.0	2.7	3.3
Less Removals	-	-	-	-	-	-	0.0
Gross Investment Cost	0.8	0.0	1.2	0.7	0.0	2.7	3.3
Less Capital Contributions	-	-	-	-	-	-	0.0
Net Investment Cost	**0.8**	**0.0**	**1.2**	**0.7**	**0.0**	**2.7**	**3.3**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

Vulnerable Energy Consumers Coalition Interrogatory # 24

Issue:

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

Reference:

B1-01-01 Section 3.2 Page: 9

Interrogatory:

a) Please explain the "lumpiness" in the General Plant spending in 2019.

b) The Board has articulated a policy of capital expenditure pacing. Please explain what programs could be delayed (or eliminated) in order for capital expenditures in 2019 through 2022 to continue on the same trend as general plant investment was between 2016 and 2018 (forecast).

Response:

Please see Exhibit I-29-Staff-167.

Vulnerable Energy Consumers Coalition Interrogatory # 25

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

Reference:
B1-01-01 Section 3.2

Interrogatory:
a) Hydro One proposes a significant increase in its system renewal capital expenditures in 2018 as compared to 2013 through 2018 (forecast). As compared to the last cost of service filing (EB-2013-0416) what new asset condition data has been gathered to support this large increase?

Response:
a) System renewal capital expenditure averaged $276.0M per year from 2013 to 2017 (actual/forecast). The 2018 forecast of $248.6M does not represent an increase over historical investment levels.

Vulnerable Energy Consumers Coalition Interrogatory # 26

Issue:

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

Reference:

B1-01-01 Section 1.4

Interrogatory:

a) Do any of Hydro One's DSP performance measures/metrics utilize reliability /outages by cause code?

b) Specifically does Hydro One have a metric which compares outages due to defective assets against the level of investment in those assets. If not why not?

c) What efforts has Hydro One made to develop a metric which ties capital investment to an understanding of how any particular investment improves reliability?

d) How are outcomes of capital investments linked to the rate making proposal for capital adjustments?

Response:

a) Yes.

b) No, Hydro One does not have a metric which compares outages due to defective assets against the level of investment in those assets. Changes in outage rates of major asset classes, such as poles, will lag changes in any investment in that asset type. For example, a change in the level of pole replacements in a given year will not materially impact the rate of pole failures in that year. Thus, the level of investment and outage rate must be analyzed independently to assess the impact of changes in investment level on outage rates. Hydro One does have several metrics which track outage rates of major asset classes which can be compared against the historical level of investment in those assets. This comparison allows Hydro One to assess the impact of investment on outage rates over time. The measures which track performance by asset are Number of Line Equipment Caused Interruptions, Number of Vegetation Caused Interruptions and Number of Substation Caused Interruptions.

c) Please refer to b), above.

d) Hydro one has identified a number of investments which will enable the company to achieve its business objectives and OEB performance outcomes; a summary of these material investments is included in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4, p.1946.

Vulnerable Energy Consumers Coalition Interrogatory # 27

Issue:

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

Reference:

B1-01-01 Section 1.4

Interrogatory:

a) The leading causes of outages are (in order of magnitude) Tree Contacts, Defective Equipment, and Schedule Outages. Taken together in 2016 these factors were approximately 80% of the duration of all outages. What quantitative evidence has Hydro One provided in this Application that its capital program will address these 3 factors sufficiently to either maintain or reduce outage duration?

b) Does Hydro One consider outage data (by cause code) to be a lagging, current or leading indicator of capital investments?

c) Whichever indicator type it is does Hydro One believe it possible to model capital investment with outage data so as to better understand the effectiveness of capital program? Specifically has Hydro One attempted to regress capital investment spending against lagged outage (by cause code) data to see if there are significant correlations? If not please explain why not?

d) Has Hydro One done an environmental scan to see if other utilities (including those not electric) or their regulators do this type of modelling? If yes what was the result of those enquiries?

Response:

a) Tree caused outages are primarily impacted through the OM&A program. See Exhibit Q, Tab 1, Schedule 1, s.2.1 for the quantitative evidence on how Hydro One expects to address Tree Contacts to improve tree related outages by 20-40%. Defective Equipment outages will be primarily addressed through system renewal investments, distribution automation and worst performing feeder improvements documented in Exhibit B1, Tab 1, Schedule 1 and Exhibit I-23-Staff-085, part a), to reduce the impact of defective equipment outages by about 20%. Scheduled outages through ongoing process and work practices improvements to bundle work and minimize impact to customers will not be reduced through the capital expenditures in this rate application.

b) Please refer to Exhibit I-29-VECC-026, part b), interrogatory response for an explanation of the relationship between capital investment and outages by asset class.

c) Hydro One has not attempted to regress capital investment spending against lagged outages because there are many factors (e.g. weather, environment, geography, length of supply, voltage level, age and condition of assets, customer density, tree density, species etc.) that impact the historical outage performance and the capital expenditures required to sustain, develop and manage an aging distribution system consistent with customer and regulatory requirements

d) No. Hydro One is not aware of any utilities or their regulators doing this type of modelling.

OEB Staff Interrogatory # 174

Issue:

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

B1-01-01 Section 1.1 Page: 31
Distribution System Plan Overview, Section 1.1.1 (5.2.1 A) KEY ELEMENTS OF THE DSP

Interrogatory:

"General Plant investment costs are generally expected to decline modestly until the end of the forecast period in 2022 except for the spending associated with the planned new Integrated System Operations Centre (ISD GP-18). This will replace the existing backup power system control and telecommunications management centers and accommodate a new security operations centre to meet business and regulatory requirements."

a) Please explain what 'business requirements' are not being met by the current Operations Centre.

b) Could these business requirements be met without constructing a new Integrated System Operations Centre?

c) Please explain what 'regulatory requirements' are not being met by the current Operations Centre.

d) Could these regulatory requirements be met without constructing a new Integrated System Operations Centre?

e) Please provide the expected benefits of this facility for the distribution system and the cost allocation calculation.

f) Please provide scope of work for the recommended alternative complete with detailed cost estimates and project schedules.

Response:

a) Hydro One's Backup Control Centre ("BUCC") is currently meeting existing business requirements. The BUCC however, remains at high risk for critical failures which can result in significant disruptions in the event that further extended outages are experienced and cannot be adequately remediated or remediated in a timely fashion. The business justifications and risk mitigation associated with the proposed ISOC are as follows:

1. Risk avoidance, due to the current facility deficiencies:
   i. Flooding in basement where computer rooms, power rooms, telecom rooms, switchgear, SONET communications, etc. are currently located.
   ii. Facility roof and building cable entry leakage.
   iii. Generator failures – No redundancy in emergency generator power.
   iv. Fire panel failures.
   v. HVAC failures, capacity limitations and system constraints as the facility is limited due to age and design of infrastructure.
   vi. High cost for retrofit / maintenance activities.
   vii. Competing demands for physical space from multiple lines of business.
   viii. Electric power capacity will not meet future requirements.
   ix. Structure is landlocked, and no expansion potential exists as the facility is surrounded by Richview TS.
   x. The BUITMC requires extensive setup during activation and cannot accommodate back office support, growth, and regulatory security requirements for access control for critical computing equipment. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and is providing first level support in the event of any communications failure. ITMC requires a new Backup Control Centre to alleviate the heightened risk at the current location.
   xi. The current site location requires maintaining an interim backup facility to perform limited functions in the event the OGCC is rendered inoperable and staff have to transition to the Richview BUCC due to activation timelines. The ISOC will eliminate this requirement.
   xii. The Security Event Monitoring (SEM) is accountable to provide cyber surveillance monitoring services and requires Data Centre capacity (not a physical tenant) to support primary operations.

xiii. Security Operations Centre and Emergency Operating Centre required to provide a primary site for operations monitoring and coordinated response for security threats to ensure business continuity.

2. Emergency Preparedness risk considerations:
   i. In a flight path (Pearson International Airport)
   ii. Between two major highways (Hwy 427 & Hwy 401)
   iii. Gas pipe lines located underneath property
   iv. Adjacent to transformer station (electrical, fire and asset failure hazard)
   v. Congested area in the event of wide spread emergencies i.e. Civil unrest, blackout, natural disaster.
   vi. Adjacent to public storage facilities

b) Construction of a new ISOC is the most viable option. Please refer to pages 1 to 5 of ISD GP-18 for alternatives considered, and rationale for rejecting the respective alternatives.

c) Hydro One's BUCC is currently in compliance with applicable regulatory requirements. The BUCC however, remains at high risk for critical failures which can result in future non-compliance in the event further extended outages are experienced and cannot be adequately remediated or remediated in a timely fashion. In the event this investment does not proceed or is delayed, key risks are described on page 16 to 18 of ISD GP-18.

For a control centre to be compliant, the required regulatory standards are outlined on page 7 and 8 of ISD GP-18.

d) Please refer to answer (b) above.

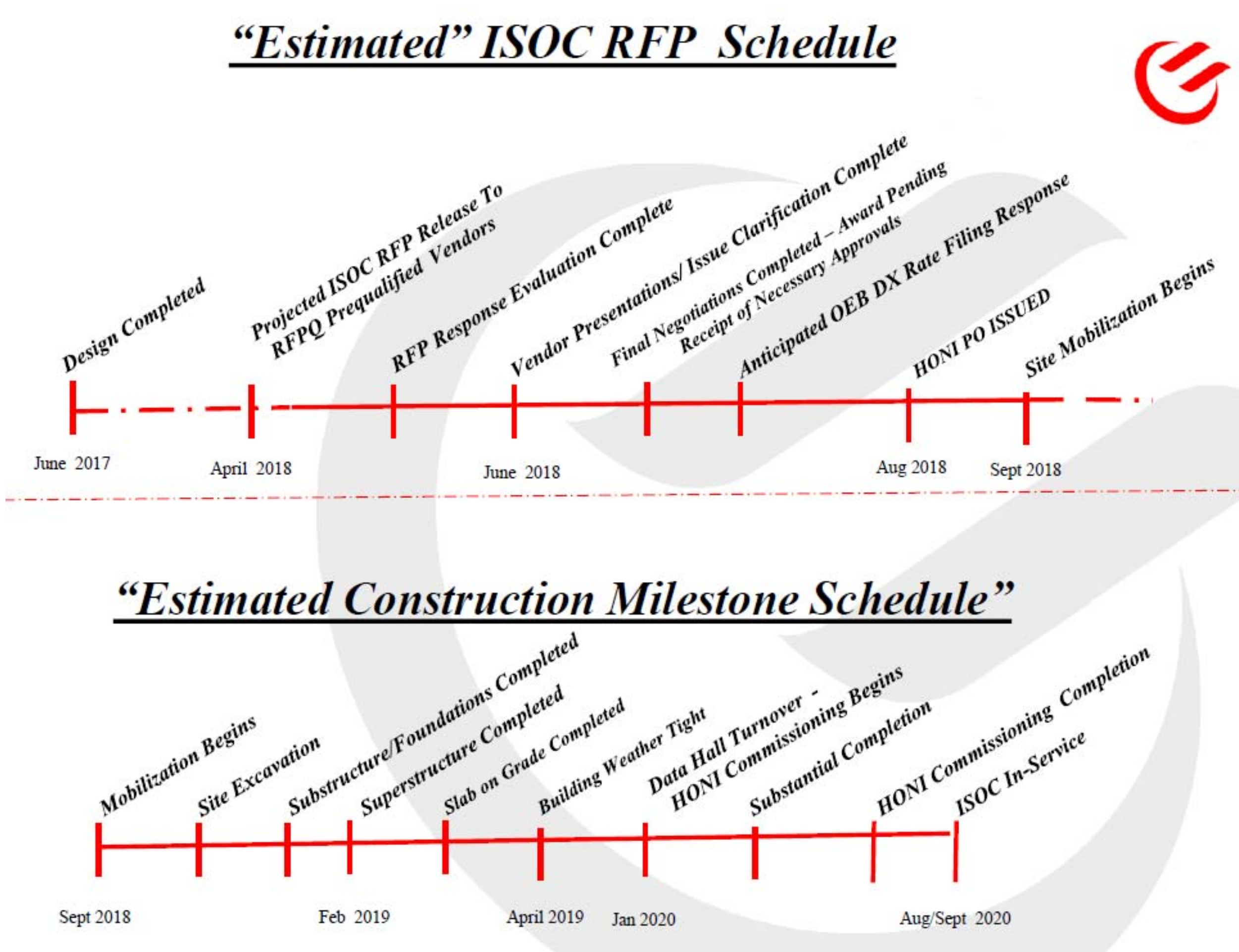
e) For expected benefits, please refer to page 9 and 10 of ISD GP-18. For cost allocation calculation, please refer to Exhibit I-24-Staff-117.

f) Pages 14 to 16 of ISD GP-18 provide a breakdown of scope of work covered in each of the phases in this investment. Cost is described in page 6 and 7 of ISD GP-18 and are summarized in the table below:

	Distribution portion only ($M)*
Land	1.5
Architecture and IT design	4.9
Construction Build (includes contingency and escalation)	51.7
Connectivity and Telecommunication	3.6
Network Infrastructure	7.6
Total:	**69.3**

*Based on Exhibit Q

Presented below is an estimated schedule for the remaining key milestones in this investment:



OEB Staff Interrogatory # 175

Issue:

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

B1-01-01 Section 3.8 Page: 2662
(5.4.5.2) Attachments: Material Investments, ISD: SS-02 System Upgrades Driven by Load Growth
EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-02 System Upgrades Driven by Load Growth

Interrogatory:

"Investment Need:
Over time, new customers connect to the system, and load growth occurs as a result. This also occurs due to increased loading at some existing customers who may increase their service sizes. This places additional stress on the elements of the distribution system. Increases in distribution station and feeder loading can lead to system elements operating at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load."

a) Please provide in Excel format a list of projects from EB-2013-0416 D-02 System Upgrades Driven by Load Growth completed in the last three years. This list should include the project name, forecast project cost, actual project cost, and explanation for material cost variances.

b) Is a business case available for each of the projects listed in ISD SS-02? If no, please provide an explanation as to why not. If yes, please provide the business case(s). It is expected the business case(s) will address the following items:

- List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
- Reliability metrics for stations and feeders involved in each project
- Station and feeder capacity
- Number of customers affected
- Proposed options, including scope of work, benefits, costs, and expected efficiency savings.

c) There are several projects that are listed in EB-2013-0416 D-02 System Upgrades Driven by Load Growth for the years 2015-2017 that seem to be repeated in SS-02 System Upgrades Driven by Load Growth. Please explain why the repeat projects were not completed in the approved year and provide an explanation on where the approved capital was spent in place of these projects.

d) For each project identified in (c) please provide the business case(s) used in EB-2013-0416 with the same information requested in (b).

Response:

a) Please refer to Attachment 1 of this Exhibit for a list of projects from EB-2013-0416 D-02 System Upgrades Driven by Load Growth completed in the last three years.

b) No. A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. At this point in time, most of the SS-02 System Upgrades Driven by Load Growth projects are planned to be in service at a future date beyond which necessitates the production of a Business Case for the purpose of authorizing the expenditure of funds for execution. Business Cases that are available can be found in Attachment 2 of this Exhibit.

c) These projects were not completed as capital was redirected to other higher priority capital investments through Hydro One’s Investment Planning Process. DSP Section 2.1 explains Hydro One’s Investment Planning Process in detail. As described in DSP Section 2.1 this process occurs on an annual basis, “Hydro One’s planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board’s filing requirement of a consolidated five-year capital plan. All investments follow this same process.” The redirected capital for these projects funded part of Hydro One’s total 2015 and 2016 actual and 2017 forecast capital expenditures. DSP Section 3.6 summarizes the result of implementing the cyclical investment planning process. DSP Section 3.6.1 summarizes the variances between forecast and historical budgets by OEB Investment Category.

d) A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. There are no Business Cases available for the projects identified in part c) as they were reprioritized and did not require authorization for the expenditure of funds for execution between 2015 and 2017.

In Reference to Exhibit EB-2013-D2-2-3 Ref#D-02			**Current Project Status**		
Project Description	**Year**	**Cost Estimate ($M)**	**Status**	**Cost ($M)**	**Cost Variance**
Brown Hill TS New Feeder Development, Queensville, East Gwillimbury	2015	3.5	Completed 2017	Note 1	NA
Clark TS M2 Feeder Reinforcement, Ilderton	2015	2.1	Completed	1.5	Scope was reduced based on more detailed engineering analysis.
Commerce Way TS M3 Feeder Reinforcement, Woodstock Surrounding Area	2015	2.1	Completed	2.6	More detailed cost estimate was developed.
Courtice DS Upgrades, Courtice, Clarington Township	2015	3	Completed	3.8 Note 2	More detailed cost estimate was developed.
Courtice DS Voltage Conversion, Courtice, Clarington Township	2015	1.8	Completed		
Nobleton DS Upgrade, Nobleton, King Township	2015	3	Completed 2017	Note 1	NA
Owen Sound TS M28 Feeder Reinforcement, Northern Bruce Pennisula	2015	1	Completed 2017	Note 1	NA
Allanburg TS M7 Feeder Reinforcement, Thorold	2016	1	Need met by another project	N/A	Need met through another project. Tie made to M6 to offload M7
Beckwith DS Upgrades, South of Carleton Place (Mississippi Mills)	2016	2.2	Complete	2.7	More detailed cost estimate was developed.
Brown Hill TS M4 Feeder Reinforcement, Georgina Township	2016	1.9	Completed 2017	Note 1	NA
Massey DS F3 Feeder Reinforcement, North Shore Algoma	2016	1	Completed	1.5	More detailed cost estimate was developed.

Note 1: 2017 actuals not available.
Note 2: Combined project cost for both Courtice DS Upgrades and Courtice DS Voltage Conversion.

Leamington TS Feeder Construction - Phase 2 Approval

Overview of Recommended Alternative:

Approval for $33.7M is requested to complete Leamington transformer station distribution line construction, thus enabling completion of the Supply to Essex County Transmission Reinforcement project. This total includes $13.6M, approved in 2016 to prepare detailed distribution line estimates, and to order materials and complete construction for phase 1 of the distribution line work.

Investment Details:

In-service: June 30, 2019

Hydro One's Board of Directors approved the Supply to Essex County Transmission Reinforcement project on May 6, 2016, which comprises the construction of Leamington Transformer Station, and a 13km 230kV transmission line. When the Board of Directors approved the Transmission business case, it was disclosed that there was a need for a separate project, to build new and modify existing distribution assets, to complete the transmission project.

Approval for the distribution system modifications will be undertaken in two dependent phases:

- Phase 1 ($13.6M) was approved in 2016 to relocate a distribution line to make way for the new transmission line and station, and some additional feeder work near the station.
- Approval is sought for Phase 2 ($20.1M), which involves installation of additional distribution poles to accommodate 8 new distribution lines from Leamington Transformer Station. Approximately 30km of distribution poles, and 50km of conductor will be installed during phase 2, which enables the removal of 2 regulating stations, and partial conversion of a distribution station.

The $33.7M cost of completing the Leamington transformer station distribution work is substantially higher than the originally anticipated $19.3M, primarily due to the unforeseen need to enhance the system with larger distribution poles to enable the expected 300MW of new load. Furthermore, the new distribution line lengths and routes have been revised since the 2014 plan, based upon completion of the investment planner's area study. The variance was further compounded by an estimating error related to the application of overhead, interest and contingency in the original estimate.

Separate approval will be sought in the future for additional transmission and distribution investments to facilitate future anticipated customer demands.

Benefits:

This investment will complete required distribution work for the Supply to Essex County Transmission Reinforcement project, and provides the following additional benefits:

- Enabling the connection of customers, with requested incremental load of 200MW
- Enhancing the distribution system to simplify the future connection of incremental load of 100MW

- Removal of two regulating stations which will no longer be required in the reconfigured distribution system, and partial conversion of two distribution stations which would have otherwise required refurbishment in the next 10 years, which will reduce future maintenance costs

Estimated Costs & In-service:

This is a multi-year project, with partial in-service additions throughout the project lifecycle.

The cost breakdown is as follows:

Category	Cost ($M)
Previous Approvals	$13.6 M
Construction of new overhead distribution lines	$8.4 M
Smart tie switches for DMS integration and DG relocation costs	$0.7 M
Construction of Duct Bank for 12 feeder egresses	$1.7 M
Phase 2 Contingency	$2.6 M
Phase 2 Interest/Overhead	$3.6 M
Phase 2 Removals	$3.1 M
Total Expenditure	$33.7 M

Construction costs are based on estimates from Provincial Lines and Engineering Services, with an accuracy of +/- 15%.

This investment is included in the 2017-2022 Business Plan, with total gross funding of $18.3M, and net funding of $10.5M. Additional funding required in 2017 will be met through deferred spending on other distribution projects. The additional budget and in-service additions outside of the current year will be included in the 2018-2022 business plan to be developed later this year.

Other Alternatives Considered

Status Quo or Do nothing Alternative
The status quo option was not considered further, as it would impact the ability of Hydro One to complete the Ontario Energy Board approved Supply to Essex County Transmission Reinforcement project, and to simplify connection of 300MW of load to the distribution system.

Regulatory Considerations

During the S.92 Leave to Construction hearing for the Supply to Essex Country Transmission Reinforcement project, the Ontario Energy Board was advised of the scope and need for this type of distribution work at a forecast cost of $19.3M.

Hydro One's next distribution rate application for years 2018 to 2022 has been filed with the Ontario Energy Board in 2017. Approval of this investment will result in an in-service additions variance of $18.7M compared to the filed rate application, and may raise the interest of the Ontario Energy Board and interveners which Hydro One may be required to defend during the hearing.

Hydro One has proposed as part of the Supply to Essex County Transmission Reinforcement Project section 92 to the Ontario Energy Board that a modified distribution cost allocation methodology will be applied. This cost allocation methodology will be finalized by the Ontario Energy Board's generic Cost Allocation hearing to decide which customers' ultimately bear the costs of the new line. Using the proposed methodology, it is forecasted that $0.3M in capital contributions will be recovered from embedded distributors.

Overall, Hydro One considers the risk of non-recovery of these expenditures to be low because this investment is required to accommodate the construction of the Supply to Essex Country Transmission Reinforcement project given S.92 approval from the Ontario Energy Board.

In-service additions approved in this Business Case may be deferred as a result of an ongoing initiative to balance in-service additions with respect to our approved Dx rates.

Risks and Mitigation

No major risks are anticipated relating to this approval.

This Approval ($): $20.1M	**Previous Approval ($):** $13.6M	**Total Approval ($):** $33.7M
Signature Block:		
Approved by: Darlene Bradley Darlene Bradley	**Title:** VP, Planning	**Date:** May 24, 2017
Approved by: Chris Lopez	**Title:** SVP, Finance	**Date:** May 24, 2017
Approved by: Gregory Kiraly Greg Kiraly	**Title:** Chief Operating Officer	**Date:** 5/24/17
Approved by: Mayo Schmidt MS	**Title:** President & Chief Executive Officer	**Date:** 5/26/17

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
Capital* and MFA	7.0	13.3	8.4	0.8	29.5
OM&A and Removals	0.7	2.0	1.3	0.2	4.2
Gross Investment Cost*	7.7	15.3	9.7	1.0	33.7
Recoverable		0.2	0.1		0.3
Net Investment Cost	7.7	15.1	9.6	1.0	33.4

*Includes capitalized interest and overhead at current rates

Rate base additions

	2016($M)	2017($M)	2018 ($M)	2019 ($M)	Total ($M)
In-Service $ Additions from estimate	-	-	25.8	3.4	29.2
In-Service $ Additions included in Business Plan	-	-	-	10.5	10.5
Variance	-	-	25.8	(7.1)	18.7

In-service Date:	June 30, 2019
Business Case Summary #:	51001418
Appropriation Request #:	23304
Subject ID #	81080
Investment Driver:	N.D.C.2.02
Productivity Cards?	No
Director	Lyla Garzouzi
Planner	Alexander Hamlyn

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

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

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

Building Owners and Managers Association Toronto Interrogatory # 22

Issue:

Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

Reference:

A-03-01 Page: 23

Interrogatory:

Please provide the 2017 forecast actuals to June 30, 2017 and most recent forecast to year end for Table 7. Please provide the approved 2017 forecast rates, and forecast 2018 rate base. What components, accounting for what percentage of the 23% are you speaking of?

Response:

The 2017 column within Table 7 in Exhibit A, Tab 3, Schedule 1 represents OEB approved revenue requirement for 2017. Hydro One does not forecast changes to its approved 2017 revenue requirement.

2017 forecast for Rate Base is provided in Table 14, Exhibit A, Tab 3, Schedule 1.

For the 2018 test year rate base, please refer to Table 7 in Exhibit Q, Tab 1, Schedule 1.

Hydro One is unsure what the question "What components, accounting for what percentage of the 23% are you speaking of?" is referring to.

Building Owners and Managers Association Toronto Interrogatory # 28

Issue:

Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

Reference:

A-03-01 Page: 30 Table 13

Interrogatory:

Very large, and increasing over the 2017 vs 2012 appeal.

a) Please explain the components of the forecast $158.3 million in forecast versus Board-approved 2017 rate base.

b) Please explain total spending on trouble calls, OM&A and capital, and how that becomes part of rate base. Please provide storm damage repairs (capitalized) relative to the last several years. What level of storm damage repair is included in each of 2018 through 2022?

Response:

a) The components contributing to the quoted $158.3 million in forecast versus Board-approved 2017 rate base are described below the referenced table. Please refer to Exhibit A, Tab 3, Schedule 1, Page 31, lines 5-10.

b) Please refer to Exhibit I-40-EnergyProbe-58 for explanation on capital and OM&A components for trouble calls.

   Please refer to Exhibit I-33-VECC-29 for Actuals/Forecast and OEB Approved In-service additions for Trouble Calls and Storm Damage.

   Please refer to Exhibit C1, Tab 1, Schedule 2, page 14 for a description of the Trouble call OM&A work program.

   Please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8, ISD SR-07 for Capital spending related to Distribution Lines Trouble Call and Storm Damage Response Program.

Building Owners and Managers Association Toronto Interrogatory # 29

Issue:
Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

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

Reference:
A-03-01 Page: 31

Interrogatory:
a) Why did cash working capital increase by 54.5 (15%) forecast versus approved in 2017?

b) Please provide details or the very large increase in rate base from 2018 to 2022 of $320 million in 2018 ($482 million above Board-approved 2017 rate base) of $378 million in 2019, $430 million in 2020, $559 million in 2021, and $500 million in 2022.

Response:
a) Please refer to Exhibit D1, Tab 1, Schedule 3 which outlines the methodology used to determine the net cash working capital requirement based on the Navigant study that was accepted by the OEB and updated as part of this filing. For a detailed analysis of the changes relative to the prior OEB approved study, please refer to Navigant's "Working Capital Requirements of Hydro One Networks – Distribution Business", which can be found on page 16 in Exhibit D1, Tab 1, Schedule 3, Attachment 1.

b) Rate base growth is driven by in-service additions. For a comprehensive analysis of how in-service additions impact rate base, please refer to Exhibit D1, Tab 1, Schedule 1. Please refer to Exhibit D1, Tab 1, Schedule 2 for a comprehensive analysis of in-service additions. Please note, that in-service additions were updated and are reflected in Exhibit Q, filed with the OEB on December 21, 2017. Please refer to page 9 of Exhibit Q, Tab 1, Schedule 1.

Building Owners and Managers Association Toronto Interrogatory # 145

Issue:
Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

Reference:
A-03-02 Page: 6

Interrogatory:
a) What is the percentage and increase in the rate base in each year, over the previous year, beginning in 2018 (over 2017) and until 2022, and in each of the capital expenditures, depreciation, return on equity, and income taxes over the same period?

b) What would the comparable numbers be if capex was, each year from 2018 to 2022, held to the rate of inflation?

c) Please confirm that, unlike the incremental capital module, that can be used in conjunction with the price cap IRM is an ICM without a materiality factor.

d) Please provide a version of Table 1 which incorporates a materiality factor in the determination of the "capital factor" accordion to the Board's formula, set out in EB-2014-0219.

Response:
a) The information requested is in the table below.

	2017 OEB Approved	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	Reference
Rate Base	$ 7,189.9	$ 7,666.4	$ 8,026.9	$ 8,430.5	$ 8,960.1	$ 9,326.5	Table 7, Q-1-1 Table 1, D1,1,1
% Change (year-over-year)		6.6%	4.7%	5.0%	6.3%	4.1%	
CapEx	$ 661.4	$ 628.1	$ 736.4	$ 699.3	$ 711.0	$ 796.5	Table 4, Q-1-1
% Change (year-over-year)		-5.0%	17.2%	-5.0%	1.7%	12.0%	
Return on Equity	$ 252.5	$ 276.0	$ 289.0	$ 303.5	$ 322.4	$ 335.6	Table 2, Q-1-1 Table 1, E1,1,1
% Change (year-over-year)		9.3%	4.7%	5.0%	6.2%	4.1%	
Income Taxes	$ 48.7	$ 65.5	$ 69.0	$ 71.5	$ 78.9	$ 79.5	Table 2, Q-1-1 Table 1, E1-1-1
% Change (year-over-year)		34.5%	5.3%	3.6%	10.3%	0.8%	

b) The table below provides the information requested assuming that CapEx is increased at the rate of inflation from 2018-2022. The OEB's 2018 inflation factor of 1.2% is used to adjust CapEx in each year.

	2017 OEB Approved	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast**	2022 Forecast**
Rate Base*	$ 7,189.9	$ 7,686.6	$ 8,037.6	$ 8,405.2	$ 8,925.3	$ 9,247.8
% Change (year-over-year)		6.9%	4.6%	4.6%	6.2%	3.6%
CapEx	$ 661.4	$ 669.3	$ 677.4	$ 685.5	$ 693.7	$ 702.0
% Change year-over-year)		1.2%	1.2%	1.2%	1.2%	1.2%
Return on Equity	$ 252.5	$ 276.7	$ 289.4	$ 302.6	$ 315.3	$ 326.7
% Change (year-over-year)		9.6%	4.6%	4.6%	4.2%	3.6%
Income Taxes	$ 48.7	$ 64.9	$ 69.2	$ 72.4	$ 78.7	$ 80.1
% Change (year-over-year)		33.3%	6.5%	4.6%	8.8%	1.7%

* Analysis assumes a $1 change in CapEx results in a $1 change in ISA.
** Includes the incremental rate base associated with the acquired utilities.

c) An ICM is a mechanism to provide funding for unanticipated, discrete, material capital investments that is unavailable to Custom IR applicants, such as Hydro One.

d) The materiality threshold referenced by BOMA is in reference to the OEB's policy for ACM and ICM recovery. As noted on page 18 of the report, "the ACM and ICM are only available to electricity distributors opting for Price Cap IR." As Hydro One has filed a Custom IR application, the materiality threshold calculation is not relevant to this proceeding. The proposed capital factor is consistent with approaches approved by the OEB in prior Custom IR proceedings (e.g. EB-2014-0016).

Building Owners and Managers Association Toronto Interrogatory # 153

Issue:

Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

Reference:

Financial Statements

Interrogatory:

a) Please provide copies of HONI's first quarter and second quarter financial statements, and when available (likely around November 7, 2017), its third quarter financial statements, including the MDAs and press releases.

b) The June 30, 2017 statement shows that assets placed in service by June 30, 2017 were $310 million. What is the most recent estimate (with date) of 2017 year end assets in service? The same document shows first half capex at $289 million. What is the most recent estimate (to date) of 2017 year end capex?

c) In the second quarter (p1), p1 states that security deposits were returned to customers with positive payment history. How many customers in each rate class received return of security deposits? What was the total dollar amount of deposits returned? Were the security deposits held in trust or otherwise separated from cash on hand?

Response:

a) Hydro One Networks does not have quarterly financial statements. The Hydro One Limited and Hydro One Inc. first, second and third quarter financial statements, MD&A and press release are provided.

b) The 2017 year end assets in service and capex will be available once the 2017 annual Hydro One Limited and Hydro One Inc. MD&A and financial statements are released.

c) Hydro One returned all security deposits for residential customers regardless of payment history, amounting to $1.7 million. Furthermore, Hydro One no longer requires a security deposit for residential customers. For general service customers, Hydro One returned security deposits to any customer with good payment history in the last 12 months. This amounted to $10.7 million. The security deposits were held in Hydro One's account. The security deposits were not held-in-trust or in a segregated account.

Hydro One Reports First Quarter Results and Increases Shareholder Dividend

Successful launch of enhanced operational efficiency platforms and online customer service solutions

Toronto, May 4, 2017 – Hydro One Limited, Ontario's largest electricity transmission and distribution company, today announced its financial and operating results for the first quarter ended March 31, 2017.

- Earnings per share of $0.28, compared to $0.35 last year, reflecting milder weather, interest rate driven reduction in allowed ROE, and favourable prior year bad debt comparisons.
- Placed $228 million of capital investments into service to improve the reliability and performance of Ontario's electric grid.
- Distribution segment five-year rate application filed under incentive regulatory framework.
- Tens of thousands of customers enrolled in enhanced paperless billing and usage alert features.
- New wireless field force automation platform launched to drive customer and operating efficiencies.
- Customer billing accuracy reaches all-time high, consistently exceeding 99%.
- Announced expansion of Hydro One Telecom's fiber-optic network to additional data centres and the launch of comprehensive cloud-based backup solutions.
- Fair Hydro Plan to be implemented later in 2017 to reduce customer electricity bills.
- Quarterly dividend increased 5% to $0.22 per share, payable June 30, 2017.

"Our enhanced executional capabilities and sharpened focus on customer service were clear during the quarter as we went live with advanced new mobile operational capabilities and enhanced customer service features," said Mayo Schmidt, President and Chief Executive Officer, Hydro One. "Our advocacy on behalf of our customers was also evident as the Province of Ontario announced its new Fair Hydro Plan which will bring significant savings to electric utility customers across Ontario starting this month."

Selected Consolidated Financial and Operating Highlights

	Three months ended March 31,	
(amounts throughout in millions of Canadian dollars, except as otherwise noted)	2017	2016
Revenues	1,658	1,686
Revenues, net of purchased power	769	790
Net income attributable to common shareholders	167	208
Basic earnings per common share (EPS)	$0.28	$0.35
Diluted EPS	$0.28	$0.35
Net cash from operating activities	471	368
Capital investments	350	379
Assets placed in-service	228	161
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,795	20,555
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,967	7,045

Key Financial Highlights

Revenues, net of power costs, for the first quarter were lower than last year by 2.7% primarily reflecting a lower average Ontario transmission peak demand and lower distribution customer energy consumption due to milder weather in the first quarter of 2017. Transmission and distribution revenues were also negatively impacted by a reduction in the 2017 allowed return on equity from 9.19% to 8.78%.

In addition to the items impacting revenue noted above, the comparability of first quarter earnings was affected by significantly lower bad debt expense in the first quarter of 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system and increased financing charges primarily due to increased weighted average long-term debt outstanding during the first quarter in 2017, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

Hydro One continues to invest to improve the reliability and performance of Ontario's electricity transmission and distribution systems, address aging power system infrastructure, facilitate connectivity to new generation sources, and improve service to customers. The Company made capital investments of $350 million during the first quarter, and placed $228 million of new assets in-service.

Common Share Dividends

Following the conclusion of the first quarter, on May 3, 2017, the Company declared a quarterly cash dividend to common shareholders of $0.22 per share to be paid on June 30, 2017 to shareholders of record on June 13, 2017. This represents a dividend increase of 5% and is the first increase since the Company instituted a post-IPO common share dividend of $0.21 per share in February 2016. The increase reflects the Company's expectation of continued long-term earnings growth.

Selected Operating Highlights

In March, the Company filed a five-year rate application with the Ontario Energy Board for 2018 to 2022 distribution rates under the OEB's incentive-based regulatory framework. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels, together with cost controls and efficiency savings to minimize the effect on customer bills.

Since launching the Company's enhanced paperless billing service earlier this year, tens of thousands of residential and small business customers have already enrolled, with many also opting to receive customized usage alert and billing arrival notifications. In addition, Hydro One's new enhanced web portal offers customers the ability to set personal preferences and receive detailed insights into their energy usage with the online Home Energy Assessment tool which provides a detailed breakdown of energy use and conservation recommendations.

The Company's new wireless field force automation platform is now launched across all operating zones. Approximately 1,800 field employees are now equipped with wireless tablets connecting them to the Company's core operating systems, including customer service programs and records. The new system is being used to process hundreds of field operations work orders every day with an expectation of better efficiency and data accuracy. Online access in the field to system mapping, site and service records, and meter bar code scanning capabilities is enabling a reduction in the number of individual service calls, improved scheduling efficiencies and enhanced workforce communications.

Customer billing accuracy has continued to improve to record levels. A combination of continued enhancements to the Company's systems, processes and quality assurance controls along every step in the meter-to-bill process, combined with ongoing fine tuning of its smart meter network to improve reliability of remote meter reading capabilities, led to time-of-use billing accuracy exceeding 99.4% for every month in the first quarter of 2017.

Hydro One Telecom announced the expansion of its broadband fiber-optic network to over 30 data centres across Ontario and Quebec, with plans to connect to 13 additional locations over the coming months. Hydro One Telecom also added comprehensive, cloud-based solutions to its portfolio to meet the growing needs of clients looking for a single, consolidated repository that simplifies backup, protection and recovery of critical data that is stored, while providing a real-time, enterprise-wide dashboard view of its status across all protected data sources.

In March, the Province announced its Fair Hydro Plan which will substantially reduce the price of electric power to our customers while improving the allocation of delivery charges across the rural and urban geographies of the province. These changes will provide significant relief to customers, particularly for those who need it the most – fixed-income, rural and Northern customers and small businesses. These initiatives were developed by the Province following extensive consultations with Hydro One and other industry participants, underscoring the Company's ongoing advocacy on behalf of its customers and is another way Hydro One is demonstrating that the Company is changing the way it does business by making every effort to lower costs and by putting customers first.

Supplemental Segment Information

(millions of Canadian dollars)	Three months ended March 31, 2017	2016
Revenues		
Transmission	367	386
Distribution	1,279	1,286
Other	12	14
Total revenues	**1,658**	**1,686**
Revenues, net of purchased power		
Transmission	367	386
Distribution	390	390
Other	12	14
Total revenues, net of purchased power	**769**	**790**
Income (loss) before financing charges and taxes		
Transmission	164	195
Distribution	153	156
Other	(14)	(7)
Total income before financing charges and taxes	**303**	**344**
Capital investments		
Transmission	209	235
Distribution	138	143
Other	3	1
Total capital investments	**350**	**379**
Assets placed in-service		
Transmission	82	51
Distribution	146	107
Other	–	3
Total assets placed in-service	**228**	**161**

This press release should be read in conjunction with the Company's first quarter 2017 Consolidated Financial Statements and Management's Discussion and Analysis (MD&A). These statements and MD&A together with additional information about Hydro One, including the full year 2016 Consolidated Financial Statements and Management's Discussion and Analysis, can be accessed at www.HydroOne.com/Investors and www.sedar.com.

Quarterly Investment Community Teleconference

The Company's first quarter 2017 results teleconference with the investment community will be held on May 4, 2017 at 8:00 a.m. Eastern Time, a webcast of which will be available at www.HydroOne.com/Investors. Members of the financial community wishing to ask questions during the call should dial 1-855-716-2690 prior to the scheduled start time and request access to Hydro One's first quarter 2017 results call, conference ID 79536095 (international callers may dial 1-440-996-5689). Media and other interested parties are welcome to participate on a listen-only basis. A webcast of the teleconference will be available at the same link following the call. Additionally, investors should note that from time to time Hydro One management presents at brokerage sponsored investor conferences. Most often, but not always, these conferences are webcast by the hosting brokerage firm, and when they are webcast, links are made available on Hydro One's website at www.HydroOne.com/Investors and are posted generally at least two days before the conference.

About Hydro One Limited

We are Ontario's largest electricity transmission and distribution provider with more than 1.3 million valued customers, $25 billion in assets and annual revenues of over $6.5 billion. Our team of 5,500 skilled and dedicated employees proudly and safely serves suburban, rural and remote communities across Ontario through our 30,000 circuit km high-voltage transmission and 123,000 circuit km primary distribution networks. Hydro One is committed to the communities we serve, and has been rated as the top utility in Canada for its corporate citizenship, sustainability, and diversity initiatives. We are one of only four utility companies in Canada to achieve the Sustainable Energy Company designation from the Canadian Electrical Association. We also provide advanced broadband telecommunications services on a wholesale basis utilizing our extensive fibre optic network. Hydro One Limited's common shares are listed on the Toronto Stock Exchange (TSX: H).

For More Information

For more information about everything Hydro One, please visit www.HydroOne.com where you can find additional information including links to securities filings, historical financial reports, and information about our governance practices, corporate social responsibility, customer solutions, and further information about our business.

Forward-Looking Statements and Information

This press release may contain "forward-looking information" within the meaning of applicable securities laws. Such information includes, but is not limited to, statements related to: growth, service, performance, reliability, efficiencies, operations, ongoing and planned investments, rate filings, dividends, the Hydro One Telecom network expansion, and the Fair Hydro Plan. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance or actions and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One's filings with the securities regulatory authorities in Canada, which are available on SEDAR at www.sedar.com. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking information, except as required by law.

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The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (the Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the three months ended March 31, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the three months ended March 31, 2017, based on information available to management as of May 3, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Three months ended March 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Revenues	1,658	1,686	(1.7%)
Purchased power	889	896	(0.8%)
Revenues, net of purchased power	769	790	(2.7%)
Operation, maintenance and administration costs	271	256	5.9%
Depreciation and amortization	195	190	2.6%
Financing charges	103	96	7.3%
Income tax expense	27	33	(18.2%)
Net income attributable to common shareholders of Hydro One	**167**	**208**	**(19.7%)**
Basic earnings per common share (EPS)	$0.28	$0.35	(19.7%)
Diluted EPS	$0.28	$0.35	(19.7%)
Net cash from operating activities	471	368	28.0%
Funds from operations (FFO)[1]	389	382	1.8%
Capital investments	350	379	(7.7%)
Assets placed in-service	228	161	41.6%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,795	20,555	(3.7%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,967	7,045	(1.1%)

	March 31, 2017	December 31, 2016
Debt to capitalization ratio[2]	52.5%	52.6%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

For the three months ended March 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	48%	51%	1%

At March 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	52%	37%	11%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the quarter ended March 31, 2017 of $167 million is a decrease of $41 million or 19.7% from the prior year. Significant influences on net income included:

- milder weather in the first quarter of 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand, and a decrease in distribution revenues, as energy consumption declined. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher operation, maintenance and administration (OM&A) costs primarily resulting from lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- increased financing charges primarily due to increased weighted average long-term debt outstanding during the first quarter of 2017 compared to the first quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

EPS

EPS was $0.28 in the first quarter of 2017, compared to EPS of $0.35 in the first quarter of 2016. The decrease in EPS was driven by lower net income in the first quarter of 2017, as discussed above.

Revenues

Three months ended March 31 *(millions of dollars, except as otherwise noted)*	**2017**	**2016**	**Change**
Transmission	367	386	(4.9%)
Distribution	1,279	1,286	(0.5%)
Other	12	14	(14.3%)
	1,658	1,686	(1.7%)
Transmission volumes:			
Average monthly Ontario 60-minute peak demand *(MW)*	19,795	20,555	(3.7%)
Distribution volumes:			
Electricity distributed to Hydro One customers *(GWh)*	6,967	7,045	(1.1%)

Transmission Revenues

Transmission revenues decreased by 4.9% for the first quarter primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased Ontario Energy Board (OEB)-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; partially offset by
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

Distribution Revenues

Distribution revenues decreased by 0.5% for the first quarter primarily due to the following:

- lower power costs from generators that are passed on to customers; and
- lower energy consumption resulting from milder weather in 2017; partially offset by
- increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**	**Change**
Transmission	102	96	6.3%
Distribution	145	141	2.8%
Other	24	19	26.3%
	271	256	5.9%

Transmission OM&A Costs

The increase of 6.3% in transmission OM&A costs for the quarter ended March 31, 2017 was primarily due to higher consulting costs related to efficiency studies, and additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

Distribution OM&A Costs

The increase of 2.8% in distribution OM&A costs for the quarter ended March 31, 2017 was primarily due to the following:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- higher consulting costs related to customer initiatives; partially offset by
- lower emergency power and storm restoration costs in 2017 as last year's costs were elevated by an ice storm in March 2016.

Other OM&A Costs

The increase in other OM&A costs for the quarter ended March 31, 2017 was primarily due to higher consulting costs related to strategy development and higher corporate management costs.

Financing Charges

The increase of $7 million or 7.3% in financing charges for the quarter ended March 31, 2017 was primarily due to an increase in interest expense on long-term debt driven by an increase in the weighted average long-term debt balance outstanding during the first quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016. This was partially offset by a decrease in the weighted average interest rate for long-term debt.

Income Tax Expense

The effective tax rate for the three months ended March 31, 2017 was 13.5% compared to 13.3% for the three months ended March 31, 2016. The decrease in income tax expense of $6 million for the quarter ended March 31, 2017 was primarily due to lower income before taxes, partially offset by changes in temporary differences included in the rate setting process such as capital cost allowance in excess of depreciation and pension contributions in excess of pension expense.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	**Record Date**	**Payment Date**	**Amount per Share**	**Total Amount** (millions of dollars)
February 9, 2017	March 14, 2016	March 31, 2017	$0.21	125

Following the conclusion of the first quarter of 2017, the Company declared a cash dividend to common shareholders reflecting an increase of 5% as follows:

Date Declared	**Record Date**	**Payment Date**	**Amount per Share**	**Total Amount** (millions of dollars)
May 3, 2017	June 13, 2017	June 30, 2017	$0.22	131

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS)*	**Mar. 31, 2017**	**Dec. 31, 2016**	**Sep. 30, 2016**	**Jun. 30, 2016**	**Mar. 31, 2016**	**Dec. 31, 2015**	**Sep. 30, 2015**	**Jun. 30, 2015**
Revenues	1,658	1,614	1,706	1,546	1,686	1,522	1,645	1,563
Purchased power	889	858	870	803	896	786	856	838
Revenues, net of purchased power	769	756	836	743	790	736	789	725
Net income to common shareholders	167	128	233	152	208	143	188	131
Basic EPS	$0.28	$0.22	$0.39	$0.26	$0.35	$0.26	$0.39	$0.27
Diluted EPS	$0.28	$0.21	$0.39	$0.25	$0.35	$0.26	$0.39	$0.27
Basic Adjusted EPS[1]	$0.28	$0.22	$0.39	$0.26	$0.35	$0.24	$0.32	$0.22
Diluted Adjusted EPS[1]	$0.28	$0.21	$0.39	$0.25	$0.35	$0.24	$0.32	$0.22

[1] See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

The following table presents Hydro One's assets placed in-service during the three months ended March 31, 2017 and 2016:

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**	**Change**
Transmission	82	51	60.8%
Distribution	146	107	36.4%
Other	–	3	(100.0%)
Total assets placed in-service	**228**	**161**	**41.6%**

Transmission assets placed in-service increased by $31 million or 60.8% during the first quarter of 2017 primarily due to the timing of a larger number of sustainment investments that were placed in-service early in 2017, including the station refurbishment projects at Richview, Nepean, Hinchinbrooke, Bruce A, and Strathroy transmission stations.

Distribution assets placed in-service increased by $39 million or 36.4% during the first quarter of 2017 primarily due to the following:

- the completion of an operation center in Bolton in February 2017;
- timing of distribution station refurbishments and spare transformer purchases as work and vendor deliveries were deferred from 2016; and
- higher volume of trouble calls and power restoration work.

The following table presents Hydro One's capital investments during the three months ended March 31, 2017 and 2016:

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**	**Change**
Transmission			
Sustaining	162	181	(10.5%)
Development	37	40	(7.5%)
Other	10	14	(28.6%)
	209	235	(11.1%)
Distribution			
Sustaining	72	86	(16.3%)
Development	47	39	20.5%
Other	19	18	5.6%
	138	143	(3.5%)
Other	3	1	200.0%
Total capital investments	**350**	**379**	**(7.7%)**

Transmission Capital Investments

Transmission capital investments decreased by $26 million or 11.1% during the first quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of sustainment project work;
- timing of work related to the Clarington Transmission Station project;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; and
- completion of the Guelph Area Transmission Refurbishment project; partially offset by
- continued work on major local area supply network development projects, such as the Holland Transmission Station and the Hawthorne Transmission Station.

Distribution Capital Investments

Distribution capital investments decreased by $5 million or 3.5% during the first quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of wood pole replacements;
- lower volume of work within station refurbishment programs; and
- decreased storm restoration work compared to prior year mainly as a result of the ice storm in March 2016; partially offset by
- higher volume of work in new connections and upgrades due to increased demand; and
- higher volume of emergency power restorations.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at March 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$16 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$203 million
East-West Tie Station Expansion	Northern Ontario	Station expansion	2020	$166 million	–
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	–
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$90 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$102 million	$72 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2020	$95 million	$25 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$35 million

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**
Cash provided by operating activities	471	368
Cash provided by (used in) financing activities	(148)	147
Cash used in investing activities	(350)	(356)
Increase (decrease) in cash and cash equivalents	**(27)**	159

Cash provided by operating activities

The increase in cash provided by operating activities is primarily due to decreased energy-related receivables as a result of lower revenues in the first quarter of 2017 primarily reflecting a lower average Ontario peak demand and lower energy consumption due to milder weather in the first quarter of 2017.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the first quarter of 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $572 million from issuance of short-term notes in the first quarter of 2017, compared to $731 million received in the first quarter of 2016.

Uses of cash

- Dividends paid in the first quarter of 2017 were $130 million, consisting of $125 million common share dividends and $5 million preferred share dividends, compared to $208 million paid in the prior year, consisting of $202 million common share dividends and $6 million preferred share dividends. Common share dividends paid in the first quarter of 2016 included $77 million for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $125 million for the quarter ended March 31, 2016.
- The Company repaid $590 million of short-term notes, compared to $1,267 million repaid in the first quarter of 2016.
- The Company repaid no long-term debt in the first quarter of 2017 compared to $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $22 million lower in the first quarter of 2017, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At March 31, 2017, Hydro One Inc. had $451 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company and Hydro One Inc. have revolving bank credit facilities totalling $2,550 million maturing in 2021. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At March 31, 2017, the Company's long-term debt in the principal amount of $10,671 million included $10,523 million long-term debt issued under Hydro One Inc.'s Medium Term Note (MTN) Program and long-term debt in the principal amount of $148 million held by Hydro One Sault Ste. Marie. At March 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at March 31, 2017, had an average term to maturity of approximately 15.6 years and a weighted average coupon rate of 4.3%.

In addition, at March 31, 2017, Hydro One had $6,030 million available under its universal short form base shelf prospectus (Universal Base Shelf Prospectus) filed in March 2016, which allows Hydro One to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018.

At March 31, 2017, the Company and Hydro One Inc. were in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

March 31, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,671	602	1,484	1,756	6,829
Long-term debt – interest payments	8,058	456	826	749	6,027
Short-term notes payable	451	451	–	–	–
Pension contributions[1]	188	103	85	–	–
Environmental and asset retirement obligations	228	28	52	66	82
Outsourcing agreements	327	152	163	6	6
Operating lease commitments	49	12	19	14	4
Long-term software/meter agreement	68	16	34	14	4
Total contractual obligations	20,040	1,820	2,663	2,605	12,952
Other commercial commitments *(by year of expiry)*					
Credit facilities	2,550	–	–	2,550	–
Letters of credit[2]	169	169	–	–	–
Guarantees[3]	325	325	–	–	–
Total other commercial commitments	3,044	494	–	2,550	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017 and 2018 minimum pension contributions are based on an actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

[2] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $12 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[3] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision pending
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Cost-of-service	OEB decision pending
Mergers Acquisitions Amalgamations and Divestitures			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,554 million	Filed in May 2016	To be filed in 2017 Q2
	2018	8.78% (F)	$11,226 million	Filed in May 2016	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Filed in December 2016
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Filed in December 2016	Filed in December 2016
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017	To be filed in 2017 Q4
	2019	8.78% (F)	$8,049 million	Filed in March 2017	To be filed in 2018 Q4
	2020	8.78% (F)	$8,477 million	Filed in March 2017	To be filed in 2019 Q4
	2021	8.78% (F)	$9,035 million	Filed in March 2017	To be filed in 2020 Q4
	2022	8.78% (F)	$9,435 million	Filed in March 2017	To be filed in 2021 Q4

Hydro One Networks

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in the first half of 2018, and that new rates will be effective on January 1, 2018.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced its Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Company's recommendation to provide a credit on the delivery charge for on-reserve First Nations customers is expected to be implemented. The Province of Ontario (Province) also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements are also planned to the existing Ontario Electricity Support Program.

Starting in the summer of 2017, a reduction of 25% is expected to be introduced on electricity bills for typical Ontario residents. This reduction is expected to include the 8% rebate from the *Ontario Rebate for Electricity Consumers Act, 2016*. The RRRP and First Nations Rate Assistance program delivery charge credit is expected to be funded from Provincial revenues, reducing regulatory charges for Ontario ratepayers. Funding for the Ontario Electricity Support Program is expected to be increased by 50%, and it is expected that the changes to the RRRP will result in distribution cost reductions of about 10% for an average low-density and medium-density Hydro One customer, consuming 1,150 kWh and 900 kWh, respectively. These changes, once implemented, are not expected to have an impact on the net revenues of the Company.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**
Net cash from operating activities	471	368
Changes in non-cash balances related to operations	(77)	23
Preferred share dividends	(5)	(6)
Distributions to noncontrolling interest	–	(3)
FFO	**389**	**382**

Adjusted EPS

The basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the quarters presented. Adjusted EPS has been used internally by management subsequent to the IPO of the Company's common shares in November 2015 to assess the Company's performance and is considered useful because it eliminates the impact of a different and non-comparable number of shares outstanding and held by the Province prior to the IPO. EPS is considered an important measure and management believes that presenting it consistently for all periods based on the number of outstanding shares on, and subsequent to, the IPO provided users with a comparative basis to evaluate the operations of the Company.

FFO and basic and diluted Adjusted EPS are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

The Province is the majority shareholder of Hydro One with approximately 70.1% ownership at March 31, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc. and subsequent to the acquisition by Alectra Inc. is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three months ended March 31, 2017 and 2016:

		Three months ended March 31	
		2017	**2016**
Related Party	**Transaction**	*(millions of dollars)*	
Province	Dividends paid	92	176
IESO	Power purchased	651	710
	Revenues for transmission services	369	376
	Amounts related to electricity rebates	77	–
	Distribution revenues related to rural rate protection	61	31
	Distribution revenues related to the supply of electricity to remote northern communities	8	8
	Funding received related to Conservation and Demand Management programs	16	7
OPG	Power purchased	4	2
	Revenues related to provision of construction and equipment maintenance services	–	1
	Costs expensed related to the purchase of services	–	1
OEFC	Power purchased from power contracts administered by the OEFC	1	–
OEB	OEB fees	2	4
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	–	1

INTERNAL CONTROLS OVER FINANCIAL REPORTING

There have been no changes in Hydro One's internal controls over financial reporting during the three months ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05	May 2014 – February 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is underway and will continue through to the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting rates and expected timing of decisions; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; future pension contributions and valuations; dividends; non-GAAP measures; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; and the Company's acquisitions, including Orillia Power Distribution Corporation. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31 *(millions of Canadian dollars, except per share amounts)*	**2017**	**2016**
Revenues		
Distribution (includes $69 related party revenues; 2016 – $40) *(Note 19)*	1,279	1,286
Transmission (includes $369 related party revenues; 2016 – $377) *(Note 19)*	367	386
Other	12	14
	1,658	1,686
Costs		
Purchased power (includes $656 related party costs; 2016 – $712) *(Note 19)*	889	896
Operation, maintenance and administration *(Note 19)*	271	256
Depreciation and amortization *(Note 4)*	195	190
	1,355	1,342
Income before financing charges and income taxes	303	344
Financing charges	103	96
Income before income taxes	200	248
Income taxes *(Note 5)*	27	33
Net income	**173**	**215**
Other comprehensive income	1	–
Comprehensive income	**174**	**215**
Net income attributable to:		
Noncontrolling interest	1	1
Preferred shareholders	5	6
Common shareholders	167	208
	173	**215**
Comprehensive income attributable to:		
Noncontrolling interest	1	1
Preferred shareholders	5	6
Common shareholders	168	208
	174	**215**
Earnings per common share *(Note 17)*		
Basic	$0.28	$0.35
Diluted	$0.28	$0.35
Dividends per common share declared *(Note 16)*	$0.21	$0.34

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At March 31, 2017 and December 31, 2016

(millions of Canadian dollars)	**March 31, 2017**	**December 31, 2016**
Assets		
Current assets:		
Cash and cash equivalents	23	50
Accounts receivable *(Note 6)*	740	838
Due from related parties	203	158
Other current assets *(Note 7)*	99	102
	1,065	1,148
Property, plant and equipment *(Note 8)*	19,324	19,140
Other long-term assets:		
Regulatory assets	3,154	3,145
Deferred income tax assets	1,180	1,235
Intangible assets (net of accumulated amortization – $344; 2016 – $330)	347	349
Goodwill	327	327
Other assets	8	7
	5,016	5,063
Total assets	**25,405**	**25,351**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 11)*	451	469
Long-term debt payable within one year *(Notes 11, 12)*	602	602
Accounts payable and other current liabilities *(Note 9)*	984	945
Due to related parties	111	147
	2,148	2,163
Long-term liabilities:		
Long-term debt (includes $549 measured at fair value; 2016 – $548) *(Notes 11, 12)*	10,080	10,078
Regulatory liabilities	211	209
Deferred income tax liabilities	61	60
Other long-term liabilities *(Note 10)*	2,766	2,752
	13,118	13,099
Total liabilities	**15,266**	**15,262**
Contingencies and Commitments (Notes 21, 22)		
Subsequent Events (Note 24)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 15)*	5,623	5,623
Preferred shares *(Note 15)*	418	418
Additional paid-in capital	40	34
Retained earnings	3,992	3,950
Accumulated other comprehensive loss	(7)	(8)
Hydro One shareholders' equity	10,066	10,017
Noncontrolling interest	51	50
Total equity	**10,117**	**10,067**
	25,405	**25,351**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31, 2017 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	–	–	–	172	–	172	1	173
Other comprehensive income	–	–	–	–	1	1	–	1
Dividends on preferred shares	–	–	–	(5)	–	(5)	–	(5)
Dividends on common shares	–	–	–	(125)	–	(125)	–	(125)
Stock-based compensation	–	–	6	–	–	6	–	6
March 31, 2017	**5,623**	**418**	**40**	**3,992**	**(7)**	**10,066**	**51**	**10,117**

Three months ended March 31, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	–	–	–	214	–	214	1	215
Distributions to noncontrolling interest	–	–	–	–	–	–	(2)	(2)
Dividends on preferred shares	–	–	–	(6)	–	(6)	–	(6)
Dividends on common shares	–	–	–	(202)	–	(202)	–	(202)
Stock-based compensation	–	–	5	–	–	5	–	5
March 31, 2016	**5,623**	**418**	**15**	**3,812**	**(8)**	**9,860**	**51**	**9,911**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31 *(millions of Canadian dollars)*	**2017**	**2016**
Operating activities		
Net income	173	215
Environmental expenditures	(4)	(3)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	174	166
Regulatory assets and liabilities	31	(10)
Deferred income taxes	20	21
Other	–	2
Changes in non-cash balances related to operations *(Note 20)*	77	(23)
Net cash from operating activities	471	368
Financing activities		
Long-term debt issued	–	1,350
Long-term debt repaid	–	(450)
Short-term notes issued	572	731
Short-term notes repaid	(590)	(1,267)
Dividends paid	(130)	(208)
Distributions paid to noncontrolling interest	–	(3)
Other	–	(6)
Net cash from (used in) financing activities	(148)	147
Investing activities		
Capital expenditures *(Note 20)*		
Property, plant and equipment	(335)	(358)
Intangible assets	(14)	(13)
Capital contributions received	7	15
Other	(8)	–
Net cash used in investing activities	(350)	(356)
Net change in cash and cash equivalents	(27)	159
Cash and cash equivalents, beginning of period	50	94
Cash and cash equivalents, end of period	**23**	**253**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). At March 31, 2017, the Province of Ontario (Province) held approximately 70.1% (December 31, 2016 – 70.1%) of the common shares of Hydro One.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05	May 2014 – February 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is underway and will continue through to the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. DEPRECIATION AND AMORTIZATION

Three months ended March 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	155	150
Asset removal costs	21	24
Amortization of intangible assets	15	13
Amortization of regulatory assets	4	3
	195	190

5. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Three months ended March 31 *(millions of dollars)*	2017	2016
Income taxes at statutory rate	53	66
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(11)	(14)
Pension contributions in excess of pension expense	(5)	(7)
Overheads capitalized for accounting but deducted for tax purposes	(4)	(4)
Interest capitalized for accounting but deducted for tax purposes	(4)	(5)
Environmental expenditures	(3)	(2)
Other	–	(1)
Net temporary differences	(27)	(33)
Net permanent differences	1	–
Total income taxes	27	33
Effective income tax rate	13.5%	13.3%

6. ACCOUNTS RECEIVABLE

(millions of dollars)	March 31, 2017	December 31, 2016
Accounts receivable – billed	437	431
Accounts receivable – unbilled	338	442
Accounts receivable, gross	775	873
Allowance for doubtful accounts	(35)	(35)
Accounts receivable, net	740	838

The following table shows the movements in the allowance for doubtful accounts for the three months ended March 31, 2017 and the year ended December 31, 2016:

(millions of dollars)	Three months ended March 31, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	6	37
Additions to allowance for doubtful accounts	(6)	(11)
Allowance for doubtful accounts – ending	(35)	(35)

7. OTHER CURRENT ASSETS

(millions of dollars)	March 31, 2017	December 31, 2016
Regulatory assets	35	37
Materials and supplies	19	19
Prepaid expenses and other assets	45	46
	99	102

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	March 31, 2017	December 31, 2016
Property, plant and equipment	27,907	27,687
Less: accumulated depreciation	(10,090)	(9,935)
	17,817	17,752
Construction in progress	1,345	1,234
Future use land, components and spares	162	154
	19,324	19,140

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	March 31, 2017	December 31, 2016
Accounts payable	171	181
Accrued liabilities	680	659
Accrued interest	130	105
Regulatory liabilities	3	–
	984	945

10. OTHER LONG-TERM LIABILITIES

(millions of dollars)	March 31, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,664	1,641
Pension benefit liability	894	900
Environmental liabilities *(Note 14)*	173	177
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	26	25
	2,766	2,752

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At March 31, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million included Hydro One's credit facilities of $250 million and Hydro One Inc.'s credit facilities of $2.3 billion.

Long-Term Debt

At March 31, 2017, $10,523 million long-term debt was outstanding under Hydro One Inc.'s Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At March 31, 2017, $1.2 billion remained available for issuance until January 2018. In addition, at March 31, 2017, the Company had long-term debt of $184 million held by Hydro One Sault Ste. Marie.

The following table presents long-term debt outstanding at March 31, 2017 and December 31, 2016:

(millions of dollars)	March 31, 2017	December 31, 2016
Notes and debentures	10,707	10,707
Add: Net unamortized debt premiums	15	15
Add: Unrealized mark-to-market gain[1]	(1)	(2)
Less: Deferred debt issuance costs	(39)	(40)
Total long-term debt	10,682	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,080	10,078

[1] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $1 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

During the three months ended March 31, 2017, Hydro One did not issue (2016 – $1,350 million) long-term debt under the MTN Program, and made no repayments (2016 – $450 million) of long-term debt.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.4
3 years	503	1.5
4 years	1,153	2.5
5 years	603	3.2
	3,842	2.9
6 – 10 years	634	3.5
Over 10 years	6,195	5.2
	10,671	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
Remainder of 2017	369
2018	425
2019	402
2020	384
2021	370
	1,950
2022-2026	1,703
2027+	4,405
	8,058

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At March 31, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at March 31, 2017 and December 31, 2016 are as follows:

	March 31, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current portion				
$50 million of MTN Series 33 notes	50	50	50	50
$500 million MTN Series 37 notes	499	499	498	498
Other notes and debentures	10,133	11,556	10,132	11,462
	10,682	12,105	10,680	12,010

Fair Value Measurements of Derivative Instruments

At March 31, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At March 31, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At March 31, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at March 31, 2017 and December 31, 2016 is as follows:

March 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	23	23	23	–	–
	23	23	23	–	–
Liabilities:					
Short-term notes payable	451	451	451	–	–
Long-term debt, including current portion	10,682	12,105	–	12,105	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	1	–	–
	11,134	12,557	452	12,105	–

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	–	–
	50	50	50	–	–
Liabilities:					
Short-term notes payable	469	469	469	–	–
Long-term debt, including current portion	10,680	12,010	–	12,010	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	–	–
	11,151	12,481	471	12,010	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the three months ended March 31, 2017 or year ended December 31, 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three months ended March 31, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three months ended March 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At March 31, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At March 31, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At March 31, 2017, the Company's provision for bad debts was $35 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At March 31, 2017, approximately 6% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At March 31, 2017 and December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At March 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings. Employer contributions made during the three months ended March 31, 2017 were $28 million (2016 – $46 million).

The following table provides the components of the net periodic benefit costs for the three months ended March 31, 2017 and 2016:

Three months ended March 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Current service cost	36	36	12	11
Interest cost	76	77	17	17
Expected return on plan assets, net of expenses[1]	(110)	(109)	–	–
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	28	31	30
Charged to results of operations[2]	13	22	14	13

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three months ended March 31, 2017, pension costs of $30 million (2016 – $50 million) were attributed to labour, of which $13 million (2016 – $22 million) was charged to operations and $17 million (2016 – $28 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

14. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the three months ended March 31, 2017 and the year ended December 31, 2016:

(millions of dollars)	Three months ended March 31, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	2	8
Expenditures	(4)	(20)
Revaluation adjustment	–	9
Environmental liabilities – ending	202	204
Less: current portion	29	27
	173	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	March 31, 2017	December 31, 2016
Undiscounted environmental liabilities	219	224
Less: discounting accumulated liabilities to present value	17	20
Discounted environmental liabilities	202	204

Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At March 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017[1]	22
2018	26
2019	25
2020	29
2021	36
Thereafter	81
	219

[1] The amounts disclosed represent amounts for the period from April 1, 2017 to December 31, 2017.

15. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At March 31, 2017 and December 31, 2016, the Company had 595 million common shares issued and outstanding.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At March 31, 2017 and December 31, 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At March 31, 2017 and December 31, 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

16. DIVIDENDS

During the three months ended March 31, 2017, preferred share dividends in the amount of $5 million (2016 – $6 million) and common share dividends in the amount of $125 million (2016 – $202 million) were declared and paid.

17. EARNINGS PER SHARE

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the Long-term Incentive Plan, which are calculated using the treasury stock method.

Three months ended March 31	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	167	208
Weighted average number of shares		
Basic	595,000,000	595,000,000
Effect of dilutive stock-based compensation plans	2,239,305	1,131,071
Diluted	597,239,305	596,131,071
EPS		
Basic	$0.28	$0.35
Diluted	$0.28	$0.35

18. STOCK-BASED COMPENSATION

Management Deferred Share Units (DSU) Plan

Under the Company’s Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One’s Board of Directors.

Three months ended March 31 *(number of DSUs)*	2017	2016
DSUs outstanding – January 1	–	–
DSUs granted	66,952	–
DSUs outstanding – March 31	66,952	–

At March 31, 2017, a liability of $2 million (December 31, 2016 – $nil), related to outstanding DSUs has been recorded at the closing price of the Company’s common shares of $24.25 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three months ended March 31, 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled, as follows:

Three months ended March 31, 2017	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2017	230,600	254,150
Units granted	267,450	218,950
Units forfeited	(14,435)	(15,885)
Units outstanding – March 31, 2017	483,615	457,215

Three months ended March 31, 2016	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2016	–	–
Units granted	124,120	149,120
Units outstanding – March 31, 2016	124,120	149,120

The grant date total fair value of the awards granted during the three months ended March 31, 2017 was $12 million (2016 – $7 million). The compensation expense recognized by the Company relating to LTIP awards during the three months ended March 31, 2017 was $1 million (2016 – $nil).

19. RELATED PARTY TRANSACTIONS

The Province is the majority shareholder of Hydro One. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

		Three months ended March 31	
		2017	2016
Related Party	Transaction	*(millions of dollars)*	
Province	Dividends paid	92	176
IESO	Power purchased	651	710
	Revenues for transmission services	369	376
	Amounts related to electricity rebates	77	–
	Distribution revenues related to rural rate protection	61	31
	Distribution revenues related to the supply of electricity to remote northern communities	8	8
	Funding received related to Conservation and Demand Management programs	16	7
OPG	Power purchased	4	2
	Revenues related to provision of construction and equipment maintenance services	–	1
	Costs expensed related to the purchase of services	–	1
OEFC	Power purchased from power contracts administered by the OEFC	1	–
OEB	OEB fees	2	4
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	–	1

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Three months ended March 31 *(millions of dollars)*	2017	2016
Accounts receivable	91	(80)
Due from related parties	(45)	21
Materials and supplies	–	1
Prepaid expenses and other assets	–	(6)
Accounts payable	(3)	6
Accrued liabilities	20	(7)
Due to related parties	(36)	(2)
Accrued interest	25	24
Long-term accounts payable and other liabilities	2	–
Post-retirement and post-employment benefit liability	23	20
	77	(23)

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Three months ended March 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(337)	(367)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	2	9
Capital expenditures – property, plant and equipment	(335)	(358)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Three months ended March 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(13)	(12)
Net change in accruals included in capital investments in intangible assets	(1)	(1)
Capital expenditures – intangible assets	(14)	(13)

Supplementary Information

Three months ended March 31 *(millions of dollars)*	2017	2016
Net interest paid	88	80
Income taxes paid	4	9

21. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

22. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

March 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	152	93	70	2	4	6
Long-term software/meter agreement	16	17	17	13	1	4
Operating lease commitments	12	11	8	10	4	4

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

March 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	–	–	–	–	2,550	–
Letters of credit[1]	169	–	–	–	–	–
Guarantees[2]	325	–	–	–	–	–

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $12 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended March 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	367	1,279	12	1,658
Purchased power	–	889	–	889
Operation, maintenance and administration	102	145	24	271
Depreciation and amortization	101	92	2	195
Income (loss) before financing charges and income taxes	164	153	(14)	303
Capital investments	209	138	3	350

Three months ended March 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	386	1,286	14	1,686
Purchased power	–	896	–	896
Operation, maintenance and administration	96	141	19	256
Depreciation and amortization	95	93	2	190
Income (loss) before financing charges and income taxes	195	156	(7)	344
Capital investments	235	143	1	379

Total Assets by Segment:

(millions of dollars)	March 31, 2017	December 31, 2016
Transmission	13,178	13,071
Distribution	9,384	9,379
Other	2,843	2,901
Total assets	25,405	25,351

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. SUBSEQUENT EVENTS

Dividends

On May 3, 2017, preferred share dividends in the amount of $4 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

Share Grant Plans

On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

hydro One

Hydro One Reports Second Quarter Results

Service enhancements, operational improvements and efficiency gains continue to gain traction while revenues reflect unseasonably mild weather and the pending decision on the transmission rate filing

Toronto, August 8, 2017 - Hydro One Limited, the parent company of Ontario's largest electricity transmission and distribution utility, today announced its financial and operating results for the second quarter ended June 30, 2017.

- Earnings per share of $0.20, compared to $0.26 last year, reflecting milder weather, delay in receipt of transmission rate decision and interest rate driven reduction in allowed ROE.
- Quarterly dividend increased 5% on May 4, 2017 to $0.22 per share.
- Announced $6.7 billion acquisition of regulated U.S. utility Avista Corporation.
- Province executed secondary share offering bringing its ownership of Hydro One below 50%.
- Capital investments of $406 million made during the quarter to improve the reliability and performance of Ontario's electric grid.
- Customer enrollment in enhanced paperless billing and usage alert features accelerates while billing accuracy continues to trend at all-time high levels, having reached 99.4%.
- Satisfaction levels enhanced as security deposits are returned to customers with positive payment histories. Winter relief program is extended by an additional month, while receivable levels continue to trend positively.
- Fair Hydro Plan fully implemented on time; rural residential customers will see average savings of 31% on their electricity bills.

"We continued to deliver on enhancing customer satisfaction and value while implementing operational improvements and efficiency gains across the organization, despite unseasonably mild weather during the second quarter," said Mayo Schmidt, President and Chief Executive Officer, Hydro One. "We recently announced the acquisition of Avista Corporation, a high quality, strategic transaction that will enable us to further enhance customer and shareholder value as we go forward together. In addition, Hydro One's full and timely implementation of Ontario's Fair Hydro Plan in early July will deliver significant savings and greater certainty for our customers."

Selected Consolidated Financial and Operating Highlights

	Three months ended June 30,		Six months ended June 30,	
(amounts throughout in millions of Canadian dollars, except as otherwise noted)	2017	2016	2017	2016
Revenues	1,371	1,546	3,029	3,232
Revenues, net of purchased power	722	743	1,491	1,533
Net income attributable to common shareholders	117	152	284	360
Basic earnings per common share (EPS)	$0.20	$0.26	$0.48	$0.61
Diluted EPS	$0.20	$0.25	$0.48	$0.60
Net cash from operating activities	280	304	751	672
Capital investments	406	417	756	796
Assets placed in-service	337	362	565	523
Transmission: Average monthly Ontario 60-minute peak demand (MW)	18,752	19,799	19,273	20,177
Distribution: Electricity distributed to Hydro One customers (GWh)	5,842	6,118	12,820	13,163

Key Financial Highlights

For the three months ended June 30, 2017, the Company reported net income attributable to common shareholders of $117 million and earnings per share of $0.20, a 23.0% reduction from last year.

Revenues, net of purchased power, for the second quarter were lower than last year by 2.8% primarily reflecting a lower average Ontario peak demand due to milder weather. Transmission and distribution revenues were also impacted by a change in the 2017 allowed return on equity from 9.19% to 8.78%.

Additionally, the comparability of second quarter earnings was affected by higher storm restoration costs as a result of multiple storms in the second quarter of 2017, higher depreciation expense due to an increase in rate base, and increased financing charges primarily due to a higher weighted average long-term debt portfolio during the second quarter in 2017, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

On a year-to-date basis, net income was $284 million and earnings per share were $0.48, a 21.1% reduction from last year. In addition to factors noted above, year-to-date net income was also impacted by milder weather in the first quarter of 2017, resulting in lower energy consumption and distribution revenues, lower bad debt expense in the first quarter of 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, higher consulting costs primarily related to the acquisition of Avista Corporation, and lower emergency power and storm restoration costs as last year was affected by an ice storm in March 2016.

The pending decision on our 2017-2018 transmission rate filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of the decision at that time.

Hydro One continues to invest to improve the reliability and performance of Ontario's electricity transmission and distribution systems, address aging power system infrastructure, facilitate connectivity to new generation sources, and improve service to customers. The Company made capital investments of $406 million during the second quarter, and placed $337 million of new assets in-service.

Selected Operating Highlights

As part of Hydro One's ongoing commitment to its customers, the Company extended its winter relief program by an additional month. This program, which has transitioned certain customers in difficult financial positions to payment plans they can afford, has both increased customer satisfaction and created savings for the Company by reducing call center and collections costs. In addition, under Hydro One's new security deposit policy effective in April 2017, it has returned 5,600 security deposits totaling $12 million back to consumer and small business customers across Ontario with consistent credit payment histories and has effectively minimized the collection and return of unnecessary security deposits while enhancing customer perceptions of Hydro One. These initiatives are creating incremental improvements in customer satisfaction, and have had positive impacts on accounts receivable levels.

Hydro One also fully implemented Ontario's Fair Hydro Plan on schedule, meeting the aggressive deadlines set by the Province. As a result of this successful and timely implementation, starting July 1, 2017, Hydro One was able to start bringing savings to its distribution customers, with an average savings of 31% for rural residential customers.

The Company's enhanced paperless eBilling service has continued to attract increasing numbers of residential and small business customers, with approximately 60,000 customers enrolled in the enhanced electronic billing service to-date. It is anticipated that over 150,000 customers will enroll by year end, thereby further improving customer satisfaction and resulting in postage and other savings for the Company. At the same time, customer billing accuracy has been maintained at record levels, remaining above 99% throughout the second quarter.

Hydro One expanded its "Get Local" effort, opening three new regional offices for customers to speak in person with Hydro One customer care specialists. The three offices are located across the province, and the same services are now also provided in the traveling Electricity Discovery Centre. Hydro One has also continued its outreach into First Nation Communities, with Company representatives recently visiting 11 different communities and assisting approximately 1,000 customers. This program has resulted in a reduction in accounts receivable levels.

Hydro One’s effort to enhance the design of its customer bill took a significant step forward with an agreement reached between Hydro One and Ontario's Ministry of Energy, allowing the Company the flexibility to materially enhance the design, readability, and clarity of its monthly customer bill, resulting in a more customer-friendly bill. The new customer bill design is expected to be launched across Hydro One’s service territory by the end of 2017.

During the second quarter, Hydro One and the members of the Canadian Union of Skilled Workers (CUSW) successfully ratified a productive new five-year labor contract which became effective on May 1, 2017. The success of these negotiations demonstrates Hydro One’s commitment to maintaining strong and productive relationships with its labour force.

Mergers and Acquisitions Update

Subsequent to the end of the quarter on July 19, 2017, Hydro one announced the $6.7 billion enterprise value acquisition of Avista Corporation, a market-leading integrated electric and gas regulated utility in the Pacific Northwestern U.S. with remarkably similar cultures and values. Hydro One and Avista combined will create a growing regulated utility leader with $31.2 billion in enterprise value and one of the top 20 largest utilities in North America focused on regulated transmission as well as electricity and natural gas local distribution. The transaction, which is expected to be accretive to Hydro One’s earnings by at least the mid-single digits in the first full year after completion, expands Hydro One into complementary and diversified regulated assets, inclusive of natural gas local distribution, as well as into five growing markets across the Pacific Northwest where it will safely and reliably serve more than two million consumer, small business and industrial customers on a combined basis. The transaction enables Hydro One’s expansion into new jurisdictions outside of Ontario, including Washington, Oregon, Montana, Idaho and Alaska, allowing higher returns on equity and experiencing customer growth. The combination of the two highly similar and complementary companies with more than 230 years of collective operational experience also provides numerous opportunities for efficiencies through enhanced scale, innovation sharing, rationalization of IT systems and increased purchasing power, resulting in cost savings and service improvements for the benefit of customers and shareholders.

Common Share Dividends

On May 4, 2017, the Company announced that it had increased its quarterly common share dividend by 5% to $0.22 per share reflecting the expectation of continued long-term earnings growth. This is the first increase since the Company instituted a post-IPO common share dividend in 2016. Following the conclusion of the second quarter, on August 8, 2017, the Company declared the second quarterly cash dividend to common shareholders at the increased rate of $0.22 per share to be paid on September 29, 2017 to shareholders of record on September 12, 2017.

Supplemental Segment Information

(millions of dollars)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Revenues				
Transmission	361	381	728	767
Distribution	998	1,152	2,277	2,438
Other	12	13	24	27
Total revenues	**1,371**	**1,546**	**3,029**	**3,232**
Revenues, net of purchased power				
Transmission	361	381	728	767
Distribution	349	349	739	739
Other	12	13	24	27
Total revenues, net of purchased power	**722**	**743**	**1,491**	**1,533**
Income (loss) before financing charges and taxes				
Transmission	159	195	323	390
Distribution	102	108	255	264
Other	(12)	(15)	(26)	(22)
Total income before financing charges and taxes	**249**	**288**	**552**	**632**
Capital investments				
Transmission	252	238	461	473
Distribution	151	178	289	321
Other	3	1	6	2
Total capital investments	**406**	**417**	**756**	**796**
Assets placed in-service				
Transmission	165	174	247	225
Distribution	164	186	310	293
Other	8	2	8	5
Total assets placed in-service	**337**	**362**	**565**	**523**

This press release should be read in conjunction with the Company's second quarter 2017 Consolidated Financial Statements and Management's Discussion and Analysis (MD&A). These statements and MD&A together with additional information about Hydro One, including the full year 2016 Consolidated Financial Statements and Management's Discussion and Analysis, can be accessed at www.HydroOne.com/Investors and www.sedar.com.

Quarterly Investment Community Teleconference

The Company's second quarter 2017 results teleconference with the investment community will be held on August 8, 2017 at 8:30 a.m. Eastern Time, a webcast of which will be available at www.HydroOne.com/Investors. Members of the financial community wishing to ask questions during the call should dial 1-855-716-2690 prior to the scheduled start time and request access to Hydro One's second quarter 2017 results call, conference ID 23370954 (international callers may dial 1-440-996-5689). Media and other interested parties are welcome to participate on a listen-only basis. A webcast of the teleconference will be available at the same link following the call. Additionally, investors should note that from time to time Hydro One management presents at brokerage sponsored investor conferences. Most often, but not always, these conferences are webcast by the hosting brokerage firm, and when they are webcast, links are made available on Hydro One's website at www.HydroOne.com/Investors and are posted generally at least two days before the conference.

About Hydro One Limited

We are Ontario's largest electricity transmission and distribution provider with more than 1.3 million valued customers, $25 billion in assets and annual revenues of over $6.5 billion. Our team of 5,500 skilled and dedicated employees proudly and safely serves suburban, rural and remote communities across Ontario through our 30,000 circuit km high-voltage transmission and 123,000 circuit km primary distribution networks. Hydro One is committed to the communities we serve, and has been rated as the top utility in Canada for its corporate citizenship, sustainability, and diversity initiatives. We are one of only four utility companies in Canada to achieve the Sustainable Energy Company designation from the Canadian Electrical Association. We also provide advanced broadband telecommunications services on a wholesale basis utilizing our extensive fibre optic network. Hydro One Limited's common shares are listed on the Toronto Stock Exchange (TSX: H).

For More Information

For more information about everything Hydro One, please visit www.HydroOne.com where you can find additional information including links to securities filings, historical financial reports, and information about our governance practices, corporate social responsibility, customer solutions, and further information about our business.

Forward-Looking Statements and Information

This press release may contain "forward-looking information" within the meaning of applicable securities laws. Such information includes, but is not limited to, statements related to: growth, customer service and satisfaction, performance, reliability, efficiencies, operational improvements, ongoing and planned investments, the Company's transmission rates filing and its anticipated timing and impacts, dividends, the Company's eBilling service and anticipated impacts, new customer bill design, collective agreements, the Fair Hydro Plan, and the acquisition of Avista Corporation. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance or actions and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One's filings with the securities regulatory authorities in Canada, which are available on SEDAR at www.sedar.com. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking information, except as required by law.

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The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (the Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the three and six months ended June 30, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the three and six months ended June 30, 2017, based on information available to management up to August 8, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

	Three months ended June 30			Six months ended June 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Revenues	1,371	1,546	(11.3%)	3,029	3,232	(6.3%)
Purchased power	649	803	(19.2%)	1,538	1,699	(9.5%)
Revenues, net of purchased power[1]	722	743	(2.8%)	1,491	1,533	(2.7%)
Operation, maintenance and administration costs	274	262	4.6%	545	518	5.2%
Depreciation and amortization	199	193	3.1%	394	383	2.9%
Financing charges	103	98	5.1%	206	194	6.2%
Income tax expense	23	33	(30.3%)	50	66	(24.2%)
Net income attributable to common shareholders of Hydro One	**117**	**152**	**(23.0%)**	**284**	**360**	**(21.1%)**
Basic earnings per common share (EPS)	$0.20	$0.26	(23.0%)	$0.48	$0.61	(21.1%)
Diluted EPS	$0.20	$0.25	(20.0%)	$0.48	$0.60	(20.0%)
Net cash from operating activities	280	304	(7.9%)	751	672	11.8%
Funds from operations (FFO)[1]	403	337	19.6%	792	719	10.2%
Capital investments	406	417	(2.6%)	756	796	(5.0%)
Assets placed in-service	337	362	(6.9%)	565	523	8.0%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	18,752	19,799	(5.3%)	19,273	20,177	(4.5%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	5,842	6,118	(4.5%)	12,820	13,163	(2.6%)

	June 30, 2017	December 31, 2016
Debt to capitalization ratio[2]	53.0%	52.6%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

For the six months ended June 30, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	49%	49%	2%

At June 30, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	52%	37%	11%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the quarter ended June 30, 2017 of $117 million is a decrease of $35 million or 23.0% from the prior year. Significant influences on net income included:

- milder weather in the second quarter of 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher operation, maintenance and administration (OM&A) costs primarily resulting from higher storm restoration costs as a result of multiple storms in the second quarter of 2017;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during the second quarter of 2017 compared to the second quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

Net income attributable to common shareholders for the six months ended June 30, 2017 of $284 million is a decrease of $76 million or 21.1% from the prior year. In addition to factors noted above, net income for the six months ended June 30, 2017 was also impacted by the following:

- decrease in distribution revenues, due to lower energy consumption mainly resulting from milder weather in the first quarter of 2017;
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system (excluding this adjustment in 2016, the bad debt expense was relatively flat year-over-year);
- higher consulting costs primarily related to the acquisition of Avista Corporation; and
- higher storm restoration costs as a result of multiple storms in the second quarter of 2017, offset by lower emergency power and storm restoration costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016.

A delay in approval of the 2017-2018 transmission rates filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of the decision at that time.

EPS

EPS was $0.20 and $0.48 in the three and six months ended June 30, 2017, respectively, compared to EPS of $0.26 and $0.61 in the comparable periods last year. The decreases in EPS were driven by lower net income for the three and six months ended June 30, 2017, as discussed above.

Revenues

	Three months ended June 30			Six months ended June 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Transmission	361	381	(5.2%)	728	767	(5.1%)
Distribution	998	1,152	(13.4%)	2,277	2,438	(6.6%)
Other	12	13	(7.7%)	24	27	(11.1%)
Total revenues	1,371	1,546	(11.3%)	3,029	3,232	(6.3%)
Transmission	361	381	(5.2%)	728	767	(5.1%)
Distribution, net of purchased power	349	349	—%	739	739	—%
Other	12	13	(7.7%)	24	27	(11.1%)
Total revenues, net of purchased power	722	743	(2.8%)	1,491	1,533	(2.7%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	18,752	19,799	(5.3%)	19,273	20,177	(4.5%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	5,842	6,118	(4.5%)	12,820	13,163	(2.6%)

Transmission Revenues

Transmission revenues decreased by 5.2% for the second quarter primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased Ontario Energy Board (OEB)-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; partially offset by
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

The decrease in transmission revenues for the six months ended June 30, 2017 of 5.1% was mainly the result of similar factors as noted above.

A delay in approval of the 2017-2018 transmission rates filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of the decision at that time.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, for the second quarter and six months ended June 30, 2017 were consistent with prior year. During the second quarter and year-to-date, lower energy consumption resulting from a milder winter in 2017 was offset by increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	99	92	7.6%	201	188	6.9%
Distribution	153	144	6.3%	298	285	4.6%
Other	22	26	(15.4%)	46	45	2.2%
	274	262	4.6%	545	518	5.2%

Transmission OM&A Costs

The increase of 7.6% in transmission OM&A costs for the quarter ended June 30, 2017 was primarily due to higher volume of environmental management program work; and additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

The increase of 6.9% in transmission OM&A costs for the six months ended June 30, 2017 was primarily due to factors noted above.

Distribution OM&A Costs

The increase of 6.3% in distribution OM&A costs for the quarter ended June 30, 2017 was primarily due higher storm restoration costs as a result of multiple storms in the second quarter of 2017.

The increase of 4.6% in distribution OM&A costs for the six months ended June 30, 2017 was impacted by:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- higher storm restoration costs as a result of multiple storms in the second quarter of 2017, offset by lower emergency power and storm restoration costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016.

Other OM&A Costs

The decrease in other OM&A costs for the quarter ended June 30, 2017 was primarily due to lower costs incurred by Hydro One Telecom Inc. (Hydro One Telecom).

Other OM&A costs for the six months ended June 30, 2017 increased slightly compared to the prior year, as higher consulting costs primarily related to the acquisition of Avista Corporation in the first quarter of 2017 were offset by lower costs incurred by Hydro One Telecom.

Financing Charges

The increase of $5 million or 5.1% in financing charges for the second quarter of 2017 was primarily due to an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during the second quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016. This was partially offset by a decrease in the weighted average interest rate for long-term debt.

The increase of $12 million or 6.2% in financing charges for the six months ended June 30, 2017 was the result of similar factors as noted above.

Income Tax Expense

The effective tax rate for the three and six months ended June 30, 2017 was 15.8% and 14.5%, respectively, compared to 17.4% and 15.1% for the three and six months ended June 30, 2016, respectively.

The decreases in income tax expense of $10 million and $16 million for the three and six months ended June 30, 2017, respectively, were primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 9, 2017	March 14, 2017	March 31, 2017	$0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$0.22	131
				256

Following the conclusion of the second quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
August 8, 2017	September 12, 2017	September 29, 2017	$0.22	131

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS)*	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015
Revenues	1,371	1,658	1,614	1,706	1,546	1,686	1,522	1,645
Purchased power	649	889	858	870	803	896	786	856
Revenues, net of purchased power	722	769	756	836	743	790	736	789
Net income to common shareholders	117	167	128	233	152	208	143	188
Basic EPS	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35	$0.26	$0.39
Diluted EPS	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35	$0.26	$0.39
Basic Adjusted EPS[1]	n/a	$0.28	$0.22	$0.39	$0.26	$0.35	$0.24	$0.32
Diluted Adjusted EPS[1]	n/a	$0.28	$0.21	$0.39	$0.25	$0.35	$0.24	$0.32

[1] See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-service

The following table presents Hydro One's assets placed in-service during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	165	174	(5.2%)	247	225	9.8%
Distribution	164	186	(11.8%)	310	293	5.8%
Other	8	2	300.0%	8	5	60.0%
Total assets placed in-service	337	362	(6.9%)	565	523	8.0%

Transmission Assets Placed In-service

Transmission assets placed in-service decreased by $9 million or 5.2% during the second quarter of 2017 primarily due to the following:

- two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in the second quarter of 2016; partially offset by
- a larger number of cumulative sustainment investments that were placed in-service in the second quarter of 2017, including the asset replacement project at Aylmer transmission station and the station reconfiguration project at Goderich transmission station; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Transmission assets placed in-service increased by $22 million or 9.8% during the six months ended June 30, 2017 primarily due to the timing of a larger number of sustainment investments that were placed in-service in the first quarter of 2017, including the station refurbishment projects at Richview, Nepean, Hinchinbrooke, Bruce A, and Strathroy transmission stations, that more than offset the decrease in transmission assets placed-in service in the second quarter of 2017 as noted above.

Distribution Assets Placed In-service

Distribution assets placed in-service decreased by $22 million or 11.8% during the second quarter of 2017 primarily due to the following:

- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service in the second quarter of 2016;
- lower volume of fleet and work equipment purchases; partially offset by
- the completion of the Move-to-Mobile project in June 2017.

Distribution assets placed in-service increased by $17 million or 5.8% during the six months ended June 30, 2017 primarily due to the completion of an operation center in Bolton in February 2017 and timing of distribution station refurbishment and spare transformer purchases in the first quarter of 2017 as work and vendor deliveries were deferred from 2016, that more than offset the decrease in distribution assets placed-in service in the second quarter of 2017 as noted above.

Capital Investments

The following table presents Hydro One's capital investments during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission						
Sustaining	197	181	8.8%	359	362	(0.8%)
Development	39	39	—%	76	79	(3.8%)
Other	16	18	(11.1%)	26	32	(18.8%)
	252	238	5.9%	461	473	(2.5%)
Distribution						
Sustaining	80	105	(23.8%)	152	195	(22.1%)
Development	62	49	26.5%	109	90	21.1%
Other	9	24	(62.5%)	28	36	(22.2%)
	151	178	(15.2%)	289	321	(10.0%)
Other	3	1	200.0%	6	2	200.0%
Total capital investments	406	417	(2.6%)	756	796	(5.0%)

Transmission Capital Investments

Transmission capital investments increased by $14 million or 5.9% during the second quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- work on the Leamington Transmission Station project to address the electricity needs in Windsor and Essex County;
- higher volume of overhead lines and component refurbishments and replacements; and
- higher volume of demand work associated with equipment failures; partially offset by
- timing of work related to the Clarington Transmission Station project; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects.

Transmission capital investments decreased by $12 million or 2.5% during the six months ended June 30, 2017. Principal impacts on the levels of capital investments included:

- substantial completion of the construction work on Clarington Transmission Station;
- lower volume of sustainment project work;
- substantial completion of the Guelph Area Transmission Refurbishment project; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- continued work on major development projects, such as the Holland, Hawthorne, and Leamington transmission stations;
- higher volume of demand work associated with equipment failures and higher volumes of spare transformer equipment purchases to ensure readiness for unplanned replacements; and
- higher volume of overhead lines and component refurbishments and replacements.

Distribution Capital Investments

Distribution capital investments decreased by $27 million or 15.2% during the second quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of wood pole replacements;
- lower volume of distribution lines sustainment work;
- lower volume of work within station refurbishment programs; and
- lower volume of fleet and work equipment purchases; partially offset by
- higher volume of storm restoration work as a result of multiple storms in the second quarter of 2017; and
- higher volume of work in new connections and upgrades due to increased demand.

Distribution capital investments decreased by $32 million or 10.0% during the six months ended June 30, 2017 primarily due to factors noted above, and were also impacted by lower storm costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016, and timing of work on the Advanced Distribution System project.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at June 30, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$35 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$210 million
East-West Tie Station Expansion	Northern Ontario	Station expansion	2021	$157 million	$5 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	—
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$95 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$75 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$43 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$33 million

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Cash provided by operating activities	280	304	751	672
Cash provided by (used in) financing activities	125	(137)	(23)	10
Cash used in investing activities	(395)	(414)	(745)	(770)
Increase (decrease) in cash and cash equivalents	10	(247)	(17)	(88)

Cash provided by operating activities

Cash from Operating Activities decreased by $24 million during the second quarter of 2017 primarily due to lower net income and changes in accrual balances, partly offset by changes in regulatory variance accounts that impact revenue.

Cash from Operating Activities increased by $79 million year-to-date primarily due to factors noted above, as well as decreased energy-related receivables as a result of lower revenues in 2017 primarily reflecting lower commodity and global adjustment prices initiated by the Province's Fair Hydro Plan and lower consumption reflecting mild weather.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the three or six months ended June 30, 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $1,006 million and $1,578 million from issuance of short-term notes in the three and six months ended June 30, 2017, respectively, compared to $764 million and $1,495 million received in the three and six months ended June 30, 2016, respectively.

Uses of cash

- Dividends paid in the three and six months ended June 30, 2017 were $135 million and $265 million, respectively, compared to dividends of $129 million and $337 million paid in the three and six months ended June 30, 2016.
- The Company repaid $742 million and $1,332 million of short-term notes in the three and six months ended June 30, 2017, respectively, compared to $771 million and $2,038 million repaid in the three and six months ended June 30, 2016, respectively.

- The Company repaid $1 million of long-term debt in the three and six months ended June 30, 2017, compared to long-term debt of $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $17 million and $39 million lower in the second quarter and year-to-date 2017, respectively, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At June 30, 2017, Hydro One Inc. had $715 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company and Hydro One Inc. have revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At June 30, 2017, the Company's long-term debt in the principal amount of $10,670 million included $10,523 million of long-term debt issued under Hydro One Inc.'s Medium Term Note (MTN) Program and long-term debt in the principal amount of $147 million held by Hydro One Sault Ste. Marie. At June 30, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at June 30, 2017, had an average term to maturity of approximately 15.4 years and a weighted average coupon rate of 4.3%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province of Ontario (Province). See "Other Developments - Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

At June 30, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

On July 19, 2017, Standard & Poor's Rating Services (S&P) revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

On July 19, 2017, S&P and Moody's Investors Service revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

June 30, 2017 (millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,670	602	2,134	1,106	6,828
Long-term debt – interest payments	7,916	437	815	739	5,925
Short-term notes payable	715	715	—	—	—
Pension contributions[1]	192	77	115	—	—
Environmental and asset retirement obligations	230	27	52	69	82
Outsourcing agreements	286	134	140	6	6
Operating lease commitments	47	12	18	13	4
Long-term software/meter agreement	64	16	34	11	3
Total contractual obligations	20,120	2,020	3,308	1,944	12,848
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,550	—	—	2,550	—
Letters of credit[3]	162	162	—	—	—
Guarantees[4]	325	325	—	—	—
Total other commercial commitments	3,037	487	—	2,550	—

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017, 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[2] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

[3] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $5 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision pending
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Cost-of-service	OEB decision pending
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,554 million	Filed in May 2016	To be filed in 2017 Q3
	2018	8.78% (F)	$11,226 million	Filed in May 2016	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Filed in December 2016	Filed in December 2016
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017[1]	To be filed in 2018 Q2
	2019	8.78% (F)	$8,050 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	8.78% (F)	$8,478 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	8.78% (F)	$9,037 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	8.78% (F)	$9,437 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7, 2017, Hydro One Networks filed an update to the application reflecting recent financial results and other adjustments.

Hydro One Networks

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application). The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in the first half of 2018, and that new rates will be effective January 1, 2018.

B2M LP

On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. Hydro One intends to file a Notice of Motion no later than August 16, 2017, requesting the OEB to review and to cancel or vary the Procedural Order.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan and First Nations Rate Assistance Program came into effect on July 1, 2017. The Company's recommendation to provide a credit on the delivery charge for on-reserve First Nations customers was implemented. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Effective July 1, 2017, a reduction of 25% was introduced on electricity bills for typical Ontario residents. This reduction includes the 8% rebate from the *Ontario Rebate for Electricity Consumers Act, 2016*, and a reduction of the RRRP charge from $0.0021/kWh to $0.0003/kWh for Ontario ratepayers. The OESP charge was removed from customer bills as of May 1, 2017.

Hydro One customers will see the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to ensure the required applications are submitted to receive the benefits associated with the First Nations Rate Assistance Program, and to receive the credit on the delivery charge.

<u>OEB Pension and Other Post-Employment Benefits (OPEB) Costs</u>

On May 18, 2017, the OEB issued a Regulatory Treatment of Pension and OPEB Costs Report (Report) that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential. Comments on implementation matters were submitted to the OEB in June 2017.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $900 million as at December 31, 2016) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Common Share Offering

On May 17, 2017, Hydro One announced the closing of a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly holds approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Pension Plan

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and projected levels of pensionable earnings, the estimated total employer annual pension contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million and $71 million, respectively. The estimated 2017 annual employer contributions have decreased by approximately $17 million from $105 million based on improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. The updated actuarial valuation resulted in a $4 million decrease in OM&A costs, which will be refunded to ratepayers through the pension cost variance deferral account in future rate applications. Subsequent to approval of the 2017-2018 transmission cost-of-service application, the decrease in OM&A costs would correspond with a decrease in revenues.

Collective Agreement

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Exemptive Relief

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under

Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation for approximately $6.7 billion (Merger). Avista Corporation is an energy company primarily involved in transmission, distribution and generation of energy, headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger, which is expected to occur by the second half of 2018, is subject to Avista Corporation common shareholder and certain regulatory and government approvals, and the satisfaction of customary closing conditions.

Convertible Debenture Offering

On July 19, 2017, in connection with the acquisition of Avista Corporation, Hydro One and its wholly-owned subsidiary, 2587264 Ontario Inc., entered into an agreement under which a syndicate of underwriters agreed to buy, on a bought deal basis, $1.4 billion aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Debentures) of Hydro One Limited (Debenture Offering). On August 1, 2017, Hydro One filed a final short form prospectus with securities regulatory authorities in Canada for the Debenture Offering. On August 2, 2017, the underwriters gave notice of the exercise in full of the over-allotment option to acquire $140 million aggregate principal amount of additional convertible debentures. The closing date for the Debentures and the over-allotment is expected to be August 9, 2017.

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Net cash from operating activities	280	304	751	672
Changes in non-cash balances related to operations	130	38	53	61
Preferred share dividends	(4)	(4)	(9)	(10)
Distributions to noncontrolling interest	(3)	(1)	(3)	(4)
FFO	403	337	792	719

Adjusted EPS

The basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the quarters presented. Adjusted EPS has been used internally by management subsequent to the IPO of the Company's common shares in November 2015 to assess the Company's performance and is considered useful because it eliminates the impact of a different and non-comparable number of shares outstanding and held by the Province prior to the IPO. EPS is considered an important measure and management believes that presenting it consistently for all periods based on the number of outstanding shares on, and subsequent to, the IPO provided users with a comparative basis to evaluate the operations of the Company.

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Revenues	1,371	1,546	3,029	3,232
Less: Purchased power	649	803	1,538	1,699
Revenues, net of purchased power	722	743	1,491	1,533

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Distribution revenues	998	1,152	2,277	2,438
Less: Purchased power	649	803	1,538	1,699
Distribution revenues, net of purchased power	349	349	739	739

FFO, basic and diluted Adjusted EPS, and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 49.9% ownership at June 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three and six months ended June 30, 2017 and 2016:

(millions of dollars)		Three months ended June 30		Six months ended June 30	
Related Party	**Transaction**	2017	2016	2017	2016
Province	Dividends paid	70	92	162	268
IESO	Power purchased	242	335	893	1,045
	Revenues for transmission services	365	375	734	751
	Amounts related to electricity rebates	63	—	140	—
	Distribution revenues related to rural rate protection	63	32	124	63
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	16	16
	Funding received related to Conservation and Demand Management programs	10	17	26	24
OPG	Power purchased	1	1	5	3
	Revenues related to provision of construction and equipment maintenance services	1	1	1	2
	Costs expensed related to the purchase of services	1	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	1	1	1
OEB	OEB fees	2	3	4	7
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	1	—	2

RISK FACTORS

Risk Factors Relating to the Merger

Hydro One may fail to complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated (including with respect to the consideration to be paid in respect of the common stock of Avista Corporation) or at all. The completion of the Merger is subject to receipt of Avista Corporation shareholder approval and satisfaction of other approval conditions, including certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US $103 million.

The purchase price could increase

Avista Corporation is a public company and its directors owe fiduciary duties to Avista Corporation shareholders, which may require them to consider competing offers to purchase the common stock of Avista Corporation as alternatives to the Merger. The Merger Agreement preserves the ability of the directors of Avista Corporation to accept an alternative or competing offer in certain circumstances if such offer constitutes a superior proposal. If a superior proposal to acquire Avista Corporation is made, and if the superior proposal results in Avista Corporation's board of directors making a recommendation change to Avista Corporation's shareholders which is adverse to Hydro One, Avista Corporation is required to negotiate in good faith with Hydro One regarding any revisions to the Merger Agreement, which could result in an increase to the purchase price of the Merger or changes to other terms and conditions of the Merger.

Length of time required to complete the Merger is unknown

As described above under "Hydro One Limited may fail to complete the Merger", the closing of the Merger is subject to the receipt of required Avista Corporation shareholder approval and certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Company's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavorable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Company could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required Avista Corporation shareholder approval and regulatory approvals and satisfying the other required closing conditions.

Foreign exchange risk

The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a significant portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional demands will be placed on Hydro One as a result of the Merger

As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of funding that would be used to fund the Merger may not be available

Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company.

There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates that could affect the underlying cost of any financing may affect the expected accretion of the Merger.

Hydro One expects to incur significant Merger-related expenses

Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approval. Additional unanticipated costs may be incurred.

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will substantially increase its amount of indebtedness following the Merger

After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US $1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a *pro forma* basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (assuming no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One will substantially increase its amount of indebtedness following the Merger and such increased indebtedness may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering could result in a downgrade of Hydro One's credit ratings

The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Reputational and Public Opinion Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the Company's 2016 annual MD&A.

Together, disclosure controls and procedures and internal control over financial reporting make up the systems that provide internal control over reporting and disclosure. These systems include policies and procedures designed to enable the reliability and timeliness of information disclosed by the Company. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior finance executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until a new Chief Financial Officer is appointed. There have been no other significant changes in the design of the Company's internal control over financial reporting during the six months ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10	May 2014 – May 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed by the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting rates and expected timing of decisions; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; collective agreements; future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEB costs; dividends; credit ratings; non-GAAP measures; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Debentures and the over-allotment option; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the risk that the Company may fail to complete the Merger; the risk that the purchase price of Avista Corporation could increase; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; and reputational and public opinion risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three and six months ended June 30, 2017 and 2016

(millions of Canadian dollars, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues				
Distribution (includes related party revenues of $71 (2016 – $41) and $140 (2016 – $81) for the three and six months ended June 30, respectively) *(Note 19)*	998	1,152	2,277	2,438
Transmission (includes related party revenues of $366 (2016 – $375) and $735 (2016 – $752) for the three and six months ended June 30, respectively) *(Note 19)*	361	381	728	767
Other	12	13	24	27
	1,371	1,546	3,029	3,232
Costs				
Purchased power (includes related party costs of $243 (2016 – $337) and $899 (2016 – $1,049) for the three and six months ended June 30, respectively) *(Note 19)*	649	803	1,538	1,699
Operation, maintenance and administration *(Note 19)*	274	262	545	518
Depreciation and amortization *(Note 4)*	199	193	394	383
	1,122	1,258	2,477	2,600
Income before financing charges and income taxes	249	288	552	632
Financing charges	103	98	206	194
Income before income taxes	146	190	346	438
Income taxes *(Note 5)*	23	33	50	66
Net income	**123**	**157**	**296**	**372**
Other comprehensive income	—	—	1	—
Comprehensive income	**123**	**157**	**297**	**372**
Net income attributable to:				
Noncontrolling interest	2	1	3	2
Preferred shareholders	4	4	9	10
Common shareholders	117	152	284	360
	123	**157**	**296**	**372**
Comprehensive income attributable to:				
Noncontrolling interest	2	1	3	2
Preferred shareholders	4	4	9	10
Common shareholders	117	152	285	360
	123	**157**	**297**	**372**
Earnings per common share *(Note 17)*				
Basic	$0.20	$0.26	$0.48	$0.61
Diluted	$0.20	$0.25	$0.48	$0.60
Dividends per common share declared *(Note 16)*	$0.22	$0.21	$0.43	$0.55

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At June 30, 2017 and December 31, 2016

(millions of Canadian dollars)	June 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	33	50
Accounts receivable *(Note 6)*	640	838
Due from related parties	256	158
Other current assets *(Note 7)*	101	102
	1,030	1,148
Property, plant and equipment *(Note 8)*	19,550	19,140
Other long-term assets:		
Regulatory assets	3,103	3,145
Deferred income tax assets	1,142	1,235
Intangible assets (net of accumulated amortization – $359; 2016 – $330)	349	349
Goodwill	327	327
Other assets	5	7
	4,926	5,063
Total assets	**25,506**	**25,351**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 11)*	715	469
Long-term debt payable within one year *(Notes 11, 12)*	602	602
Accounts payable and other current liabilities *(Note 9)*	902	945
Due to related parties	4	147
	2,223	2,163
Long-term liabilities:		
Long-term debt (includes $546 measured at fair value; 2016 – $548) *(Notes 11, 12)*	10,072	10,078
Regulatory liabilities	223	209
Deferred income tax liabilities	63	60
Other long-term liabilities *(Note 10)*	2,795	2,752
	13,153	13,099
Total liabilities	**15,376**	**15,262**
Contingencies and Commitments (Notes 21, 22)		
Subsequent Events (Note 24)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 15)*	5,631	5,623
Preferred shares *(Note 15)*	418	418
Additional paid-in capital	38	34
Retained earnings	3,978	3,950
Accumulated other comprehensive loss	(7)	(8)
Hydro One shareholders' equity	10,058	10,017
Noncontrolling interest	50	50
Total equity	**10,108**	**10,067**
	25,506	**25,351**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the six months ended June 30, 2017 and 2016

Six months ended June 30, 2017 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	—	—	—	293	—	293	2	295
Other comprehensive income	—	—	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	(2)	(2)
Dividends on preferred shares	—	—	—	(9)	—	(9)	—	(9)
Dividends on common shares	—	—	—	(256)	—	(256)	—	(256)
Common shares issued	8	—	(8)	—	—	—	—	—
Stock-based compensation	—	—	12	—	—	12	—	12
June 30, 2017	**5,631**	**418**	**38**	**3,978**	**(7)**	**10,058**	**50**	**10,108**

Six months ended June 30, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	370	—	370	1	371
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(3)	(3)
Dividends on preferred shares	—	—	—	(10)	—	(10)	—	(10)
Dividends on common shares	—	—	—	(327)	—	(327)	—	(327)
Stock-based compensation	—	—	11	—	—	11	—	11
June 30, 2016	**5,623**	**418**	**21**	**3,839**	**(8)**	**9,893**	**50**	**9,943**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and six months ended June 30, 2017 and 2016

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2017	2016	2017	2016
Operating activities				
Net income	123	157	296	372
Environmental expenditures	(8)	(7)	(12)	(10)
Adjustments for non-cash items:				
Depreciation and amortization (excluding asset removal costs)	176	170	350	336
Regulatory assets and liabilities	93	(12)	124	(22)
Deferred income taxes	18	36	38	57
Other	8	(2)	8	—
Changes in non-cash balances related to operations *(Note 20)*	(130)	(38)	(53)	(61)
Net cash from operating activities	280	304	751	672
Financing activities				
Long-term debt issued	—	—	—	1,350
Long-term debt repaid	(1)	—	(1)	(450)
Short-term notes issued	1,006	764	1,578	1,495
Short-term notes repaid	(742)	(771)	(1,332)	(2,038)
Dividends paid	(135)	(129)	(265)	(337)
Distributions paid to noncontrolling interest	(3)	(1)	(3)	(4)
Other	—	—	—	(6)
Net cash from (used in) financing activities	125	(137)	(23)	10
Investing activities				
Capital expenditures *(Note 20)*				
Property, plant and equipment	(378)	(399)	(713)	(757)
Intangible assets	(19)	(15)	(33)	(28)
Capital contributions received	2	—	9	15
Other	—	—	(8)	—
Net cash used in investing activities	(395)	(414)	(745)	(770)
Net change in cash and cash equivalents	10	(247)	(17)	(88)
Cash and cash equivalents, beginning of period	23	253	50	94
Cash and cash equivalents, end of period	**33**	**6**	**33**	**6**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). At June 30, 2017, the Province of Ontario (Province) held approximately 49.9% (December 31, 2016 – 70.1%) of the common shares of Hydro One.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10	May 2014 – May 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed by the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. DEPRECIATION AND AMORTIZATION

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Depreciation of property, plant and equipment	154	149	309	299
Asset removal costs	23	23	44	47
Amortization of intangible assets	14	14	29	27
Amortization of regulatory assets	8	7	12	10
	199	193	394	383

5. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	Six months ended June 30	
(millions of dollars)	2017	2016
Income taxes at statutory rate	92	116
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(21)	(23)
Pension contributions in excess of pension expense	(5)	(8)
Overheads capitalized for accounting but deducted for tax purposes	(7)	(7)
Interest capitalized for accounting but deducted for tax purposes	(6)	(9)
Environmental expenditures	(4)	(4)
Other	(1)	—
Net temporary differences	(44)	(51)
Net permanent differences	2	1
Total income taxes	50	66
Effective income tax rate	14.5%	15.1%

6. ACCOUNTS RECEIVABLE

(millions of dollars)	June 30, 2017	December 31, 2016
Accounts receivable – billed	362	431
Accounts receivable – unbilled	312	442
Accounts receivable, gross	674	873
Allowance for doubtful accounts	(34)	(35)
Accounts receivable, net	640	838

The following table shows the movements in the allowance for doubtful accounts for the six months ended June 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Six months ended June 30, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	12	37
Additions to allowance for doubtful accounts	(11)	(11)
Allowance for doubtful accounts – ending	(34)	(35)

7. OTHER CURRENT ASSETS

(millions of dollars)	June 30, 2017	December 31, 2016
Regulatory assets	31	37
Materials and supplies	19	19
Prepaid expenses and other assets	51	46
	101	102

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	June 30, 2017	December 31, 2016
Property, plant and equipment	28,181	27,687
Less: accumulated depreciation	(10,237)	(9,935)
	17,944	17,752
Construction in progress	1,443	1,234
Future use land, components and spares	163	154
	19,550	19,140

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	June 30, 2017	December 31, 2016
Accounts payable	176	181
Accrued liabilities	621	659
Accrued interest	103	105
Regulatory liabilities	2	—
	902	945

10. OTHER LONG-TERM LIABILITIES

(millions of dollars)	June 30, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,681	1,641
Pension benefit liability	897	900
Environmental liabilities *(Note 14)*	179	177
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	29	25
	2,795	2,752

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At June 30, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million included Hydro One's credit facilities of $250 million and Hydro One Inc.'s credit facilities of $2.3 billion. In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

Long-Term Debt

At June 30, 2017, long-term debt of $10,523 million was outstanding under Hydro One Inc.'s Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At June 30, 2017, $1.2 billion remained available for issuance until January 2018. In addition, at June 30, 2017, the Company had long-term debt of $180 million related to Hydro One Sault Ste. Marie.

The following table presents long-term debt outstanding at June 30, 2017 and December 31, 2016:

(millions of dollars)	June 30, 2017	December 31, 2016
Notes and debentures	10,703	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[1]	(4)	(2)
Less: Deferred debt issuance costs	(39)	(40)
Total long-term debt	10,674	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,072	10,078

[1] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $4 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

During the six months ended June 30, 2017, Hydro One did not issue (2016 – issued $1,350 million), and repaid $1 million (2016 – $450 million) of long-term debt.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.4
3 years	1,153	2.3
4 years	503	1.9
5 years	603	3.2
	3,842	2.9
6 – 10 years	633	3.5
Over 10 years	6,195	5.2
	10,670	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments (millions of dollars)
Remainder of 2017	227
2018	425
2019	402
2020	384
2021	370
	1,808
2022-2026	1,703
2027+	4,405
	7,916

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At June 30, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at June 30, 2017 and December 31, 2016 are as follows:

	June 30, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current portion				
$50 million of MTN Series 33 notes	50	50	50	50
$500 million MTN Series 37 notes	496	496	498	498
Other notes and debentures	10,128	11,779	10,132	11,462
	10,674	12,325	10,680	12,010

Fair Value Measurements of Derivative Instruments

At June 30, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At June 30, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At June 30, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at June 30, 2017 and December 31, 2016 is as follows:

June 30, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	33	33	33	—	—
	33	33	33	—	—
Liabilities:					
Short-term notes payable	715	715	715	—	—
Long-term debt, including current portion	10,674	12,325	—	12,325	—
Derivative instruments					
Fair value hedges – interest-rate swaps	4	4	4	—	—
	11,393	13,044	719	12,325	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the six months ended June 30, 2017 or year ended December 31, 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three and six months ended June 30, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and six months ended June 30, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At June 30, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At June 30, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At June 30, 2017, the Company's provision for bad debts was $34 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At June 30, 2017, approximately 7% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At June 30, 2017 and

December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At June 30, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million, and $71 million, respectively, based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Employer contributions made during the six months ended June 30, 2017 were $47 million (2016 – $75 million).

The following tables provide the components of the net periodic benefit costs for the three and six months ended June 30, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Three months ended June 30 *(millions of dollars)*	**2017**	**2016**	**2017**	**2016**
Current service cost	37	36	12	10
Interest cost	76	77	17	17
Expected return on plan assets, net of expenses[1]	(111)	(108)	—	—
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	29	31	29
Charged to results of operations[2]	8	3	13	11

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Six months ended June 30 *(millions of dollars)*	**2017**	**2016**	**2017**	**2016**
Current service cost	73	72	24	21
Interest cost	152	154	34	34
Expected return on plan assets, net of expenses[1]	(221)	(217)	—	—
Actuarial loss amortization	40	48	4	4
Net periodic benefit costs	44	57	62	59
Charged to results of operations[2]	21	25	27	24

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three and six months ended June 30, 2017, pension costs of $16 million (2016 – $7 million) and $46 million (2016 – $57 million), respectively, were attributed to labour, of which $8 million (2016 – $3 million) and $21 million (2016 – $25 million), respectively, were charged to operations, and $8 million (2016 – $4 million) and $25 million (2016 – $32 million) respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

14. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the six months ended June 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Six months ended June 30, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	4	8
Expenditures	(12)	(20)
Revaluation adjustment	11	9
Environmental liabilities – ending	207	204
Less: current portion	(28)	(27)
	179	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	June 30, 2017	December 31, 2016
Undiscounted environmental liabilities	221	224
Less: discounting accumulated liabilities to present value	14	20
Discounted environmental liabilities	207	204

Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At June 30, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017 [1]	15
2018	25
2019	25
2020	30
2021	37
Thereafter	89
	221

[1] The amounts disclosed represent amounts for the period from July 1, 2017 to December 31, 2017.

15. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At June 30, 2017, the Company had 595,385,325 (December 31, 2016 – 595,000,000) common shares issued and outstanding.

The following table presents the changes to common shares during the six months ended June 30, 2017. There was no movement in common shares during the year ended December 31, 2016.

(number of shares)	
Common shares – December 31, 2016	595,000,000
Common shares issued – share grants *(a)*	371,611
Common shares issued – LTIP *(b)*	13,714
Common shares – June 30, 2017	595,385,325

(a) On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

(b) On May 31, 2017, Hydro One issued from treasury 13,714 common shares to eligible employees in accordance with provisions of the Long-term Incentive Plan (LTIP).

Secondary Common Share Offering

On May 17, 2017, Hydro One announced the closing of a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Following completion of the Offering, the Province directly holds approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At June 30, 2017 and December 31, 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At June 30, 2017 and December 31, 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

16. DIVIDENDS

During the three months ended June 30, 2017, preferred share dividends in the amount of $4 million (2016 – $4 million) and common share dividends in the amount of $131 million (2016 – $125 million) were declared.

During the six months ended June 30, 2017, preferred share dividends in the amount of $9 million (2016 – $10 million) and common share dividends in the amount of $256 million (2016 – $327 million) were declared.

17. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the Long-term Incentive Plan, which are calculated using the treasury stock method.

	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	117	152	284	360
Weighted average number of shares				
Basic	595,372,048	595,000,000	595,187,052	595,000,000
Effect of dilutive stock-based compensation plans	2,028,575	1,574,109	1,917,218	1,363,976
Diluted	597,400,623	596,574,109	597,104,270	596,363,976
EPS				
Basic	$0.20	$0.26	$0.48	$0.61
Diluted	$0.20	$0.25	$0.48	$0.60

18. STOCK-BASED COMPENSATION

Share Grant Plans

The following table presents a summary of share grant activity under the Company's Share Grant Plans during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Share grants outstanding – beginning	5,334,415	5,412,354	5,334,415	5,412,354
Vested[1]	(371,611)	—	(371,611)	—
Share grants outstanding – ending	4,962,804	5,412,354	4,962,804	5,412,354

[1] On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

Directors' Deferred Share Units (DSU) Plan

During the three and six months ended June 30, 2017 and 2016, the Company granted awards under its Directors' DSU Plan, as follows:

	Three months ended June 30		Six months ended June 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	119,763	40,465	99,083	20,525
DSUs granted	21,790	18,740	42,470	38,680
DSUs outstanding – ending	141,553	59,205	141,553	59,205

At June 30, 2017, a liability of $3 million (December 31, 2016 – $2 million) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $23.23 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Company's Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the three and six months ended June 30, 2017 and 2016, the Company granted awards under its Management' DSU Plan, as follows:

	Three months ended June 30		Six months ended June 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	66,952	—	—	—
DSUs granted	631	—	67,583	—
DSUs outstanding – ending	67,583	—	67,583	—

At June 30, 2017, a liability of $2 million (December 31, 2016 – $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $23.23 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three and six months ended June 30, 2017 and 2016, the Company granted awards under its LTIP, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled, as follows:

	PSUs		RSUs	
Three months ended June 30 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	483,615	124,120	457,215	149,120
Units granted	—	—	—	—
Units vested	—	—	(13,470)	—
Units forfeited	(40,520)	—	(34,100)	—
Units outstanding – ending	443,095	124,120	409,645	149,120

	PSUs		RSUs	
Six months ended June 30 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	230,600	—	254,150	—
Units granted	267,450	124,120	218,950	149,120
Units vested	—	—	(13,470)	—
Units forfeited	(54,955)	—	(49,985)	—
Units outstanding – ending	443,095	124,120	409,645	149,120

The grant date total fair value of the awards granted during the three and six months ended June 30, 2017 was $nil and $12 million (2016 – $nil and $7 million), respectively. The compensation expense recognized by the Company relating to LTIP awards during the three and six months ended June 30, 2017 was $2 million and $3 million (2016 – not significant), respectively.

19. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 49.9% ownership at June 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

(millions of dollars)		Three months ended June 30		Six months ended June 30	
Related Party	**Transaction**	**2017**	**2016**	**2017**	**2016**
Province	Dividends paid	70	92	162	268
IESO	Power purchased	242	335	893	1,045
	Revenues for transmission services	365	375	734	751
	Amounts related to electricity rebates	63	—	140	—
	Distribution revenues related to rural rate protection	63	32	124	63
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	16	16
	Funding received related to Conservation and Demand Management programs	10	17	26	24
OPG	Power purchased	1	1	5	3
	Revenues related to provision of construction and equipment maintenance services	1	1	1	2
	Costs expensed related to the purchase of services	1	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	1	1	1
OEB	OEB fees	2	3	4	7
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	1	—	2

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Accounts receivable	100	91	191	11
Due from related parties	(53)	(21)	(98)	—
Materials and supplies	—	—	—	1
Prepaid expenses and other assets	(3)	(23)	(3)	(29)
Accounts payable	4	14	1	20
Accrued liabilities	(61)	31	(41)	24
Due to related parties	(107)	(131)	(143)	(133)
Accrued interest	(27)	(19)	(2)	5
Long-term accounts payable and other liabilities	—	4	2	4
Post-retirement and post-employment benefit liability	17	16	40	36
	(130)	(38)	(53)	(61)

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Capital investments in property, plant and equipment	(391)	(401)	(728)	(768)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	13	2	15	11
Capital expenditures – property, plant and equipment	(378)	(399)	(713)	(757)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Capital investments in intangible assets	(15)	(16)	(28)	(28)
Net change in accruals included in capital investments in intangible assets	(4)	1	(5)	—
Capital expenditures – intangible assets	(19)	(15)	(33)	(28)

Supplementary Information

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Net interest paid	131	122	219	202
Income taxes paid	4	6	8	15

21. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

22. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

June 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	134	93	47	2	4	6
Long-term software/meter agreement	16	17	17	9	2	3
Operating lease commitments	12	10	8	9	4	4

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

June 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	—	2,550	—
Letters of credit[1]	162	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $5 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended June 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	361	998	12	1,371
Purchased power	—	649	—	649
Operation, maintenance and administration	99	153	22	274
Depreciation and amortization	103	94	2	199
Income (loss) before financing charges and income taxes	159	102	(12)	249
Capital investments	252	151	3	406

Three months ended June 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	381	1,152	13	1,546
Purchased power	—	803	—	803
Operation, maintenance and administration	92	144	26	262
Depreciation and amortization	94	97	2	193
Income (loss) before financing charges and income taxes	195	108	(15)	288
Capital investments	238	178	1	417

Six months ended June 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	728	2,277	24	3,029
Purchased power	—	1,538	—	1,538
Operation, maintenance and administration	201	298	46	545
Depreciation and amortization	204	186	4	394
Income (loss) before financing charges and income taxes	323	255	(26)	552
Capital investments	461	289	6	756

Six months ended June 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	767	2,438	27	3,232
Purchased power	—	1,699	—	1,699
Operation, maintenance and administration	188	285	45	518
Depreciation and amortization	189	190	4	383
Income (loss) before financing charges and income taxes	390	264	(22)	632
Capital investments	473	321	2	796

Total Assets by Segment:

(millions of dollars)	June 30, 2017	December 31, 2016
Transmission	13,344	13,071
Distribution	9,318	9,379
Other	2,844	2,901
Total assets	25,506	25,351

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. SUBSEQUENT EVENTS

Dividends

On August 8, 2017, preferred share dividends in the amount of $5 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation for approximately $6.7 billion (Merger). Avista Corporation is an energy company primarily involved in transmission, distribution and generation of energy, headquartered in

Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger, which is expected to occur by the second half of 2018, is subject to Avista Corporation common shareholder and certain regulatory and government approvals, and the satisfaction of customary closing conditions.

Convertible Debenture Offering

On July 19, 2017, in connection with the acquisition of Avista Corporation, Hydro One and its wholly-owned subsidiary, 2587264 Ontario Inc., entered into an agreement under which a syndicate of underwriters agreed to buy, on a bought deal basis, $1.4 billion aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Debentures) of Hydro One Limited (Debenture Offering). On August 1, 2017, Hydro One filed a final short form prospectus with securities regulatory authorities in Canada for the Debenture Offering. On August 2, 2017, the underwriters gave notice of the exercise in full of the over-allotment option to acquire $140 million aggregate principal amount of additional convertible debentures. The closing date for the Debentures and the over-allotment is expected to be August 9, 2017.

Hydro One Reports Third Quarter Results

Improved customer service, innovative operational productivity programs and strategic acquisition demonstrate the company's momentum and transformation into a commercially-focused organization

TORONTO, November 10, 2017 - Hydro One Limited (Hydro One or the Company), the parent company of Ontario's largest electricity transmission and distribution utility, today announced its financial and operating results for the third quarter ended September 30, 2017.

- Third quarter results reflect the Ontario Energy Board's (OEB) Hydro One Networks Inc. transmission rates decision, leading to catch-up revenues for three quarters of $55 million and contributing to third quarter earnings per share of $0.37 and adjusted earnings per share of $0.40, compared to $0.39 last year.
- Hydro One and Avista Corporation filed joint applications with state utility and federal commissions for regulatory approval of the merger as planned.
- Subsequent to the July announcement of the proposed Avista Corporation acquisition, Hydro One issued approximately $1.5 billion of convertible debentures, which were oversubscribed.
- Achieved productivity savings through operational improvements, such as a revised vegetation management approach, fleet optimization and competitive procurement.
- Hydro One demonstrated operational excellence as part of the unprecedented Hurricane Irma restoration effort in Florida.
- Customer service initiatives related to affordability resulted in stabilized accounts receivable levels.
- Continued recognition as a leading utility, being awarded the Progressive Aboriginal Relations Bronze Certification for demonstrating a commitment to Aboriginal communities and the Ontario Energy Association's 2017 Leader of the Year award.

"This quarter was marked by our Avista transaction and the mild summer weather. Our joint regulatory filings with Avista were a major milestone in accomplishing this high-quality transaction that will provide long-term benefits for customers and shareholders," said Mayo Schmidt, President and Chief Executive Officer, Hydro One. "Our operational excellence program continues to deliver savings, keeping us on plan, and our exceptional performance during recent storms in Ontario and Florida speaks to our North American reputation for safety, excellent workmanship and friendly service."

Selected Consolidated Financial and Operating Highlights

(amounts throughout in millions of Canadian dollars, except as otherwise noted)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Revenues	1,522	1,706	4,551	4,938
Purchased power	675	870	2,213	2,569
Revenues, net of purchased power[1]	847	836	2,338	2,369
Net income attributable to common shareholders	219	233	503	593
Costs related to acquisition of Avista Corporation	18	—	21	—
Adjusted net income attributable to common shareholders[1]	237	233	524	593
Basic earnings per common share (EPS)	$0.37	$0.39	$0.85	$1.00
Diluted EPS	$0.37	$0.39	$0.84	$0.99
Adjusted basic EPS[1]	$0.40	$0.39	$0.88	$1.00
Adjusted diluted EPS[1]	$0.40	$0.39	$0.88	$0.99
Net cash from operating activities	442	510	1,193	1,182
Capital investments	380	424	1,136	1,220
Assets placed in-service	294	383	859	906
Transmission: Average monthly Ontario 60-minute peak demand (MW)	20,857	22,991	19,801	21,115
Distribution: Electricity distributed to Hydro One customers (GWh)	6,226	6,621	19,046	19,784

[1] **Non-GAAP Measures -** Hydro One uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America (US GAAP) and may not be comparable to similar measures presented by other entities. Hydro One calculated the non-GAAP measures by adjusting certain US GAAP measures for specific items that impact comparability but which the Company does not consider part of normal, ongoing operations. Refer to the Non-GAAP Measures section of the Company's Management's Discussion and Analysis for further discussion of these items.

Key Financial Highlights

For the three months ended September 30, 2017, the Company reported net income attributable to common shareholders of $219 million (2016 - $233 million), and earnings per share of $0.37 (2016 - $0.39), a 6.0% reduction from last year. Adjusted earnings per share, which exclude the impact of $18 million costs related to the Avista Corporation acquisition, were $0.40 for the quarter.

Revenues, net of purchased power, for the third quarter were higher than last year by 1.3% primarily reflecting higher transmission revenues driven by the OEB's decision on Hydro One Networks Inc.'s 2017-2018 transmission rates filing, partially offset by lower average Ontario peak demand and lower energy consumption due to milder weather, as well as a reduction in the 2017 allowed return on equity from 9.19% to 8.78%.

The comparability of third quarter earnings was negatively impacted by higher consulting costs primarily related to the acquisition of Avista Corporation, higher depreciation expense due to an increase in rate base and increased financing charges primarily due to a higher weighted average long-term debt portfolio as well as the issuance of convertible debentures in August 2017, partially offset by reduced vegetation management costs.

On a year-to-date basis, the Company reported net income of $503 million (2016 - $593 million), and earnings per share of $0.85 (2016 - $1.00), a 15.2% reduction from last year. Adjusted earnings per share are $0.88 year-to-date. In addition to factors noted above, year-to-date net income was also impacted by a significantly lower bad debt expense in the first quarter of 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, the bad debt expense was relatively flat year-over-year).

Hydro One continues to invest to improve the reliability and performance of Ontario's electricity transmission and distribution systems, address aging power system infrastructure, facilitate connectivity to new generation sources, and improve service to customers. The Company made capital investments of $380 million during the third quarter, and placed $294 million of new assets in-service.

Selected Operating Highlights

Subsequent to the July 2017 announcement of the proposed Avista Corporation acquisition, Hydro One issued approximately $1.5 billion of convertible debentures, which were oversubscribed. Enthusiasm for the bought deal offering is reflective of the market's confidence in the Company's growth strategy.

The Company achieved significant productivity savings in the third quarter through a new vegetation management approach, fleet optimization and a more competitive procurement process, along with other initiatives. In September, Hydro One introduced a shortened and targeted vegetation management program that is expected to result in long-term productivity savings as well as improved reliability and community relations.

At the same time, the use of telematics data to evaluate the productivity of the Company's fleet resulted in current and future capital savings. Savings were also achieved through a reduction in prices paid for procured materials and services by consolidating spending to exercise purchasing power and introducing a revised, more streamlined bidding process.

Over a period of 14 days in September, Hydro One mobilized 175 employees to help restore power to more than 10,000 Florida residents after Hurricane Irma pummeled the state and surrounding region. While in Florida, Hydro One's employees were assigned challenging work in tough conditions and their actions contributed to establishing a strong reputation for operational excellence as well as commitment to safety.

The introduction of several relief and affordability measures proved to be effective in helping customers manage electricity usage and keep accounts current. Building on the success of the Company's extended Winter Relief program, the elimination and return of security deposits as well as additional outreach to customers at risk, accounts receivable levels have fallen to a four-year low. Overdue accounts have declined by 25% year-over-year to $86 million at the end of September. The number of customers disconnected for non-payment has declined by nearly 60% year-over-year.

As part of its new commitment to improving customer service, Hydro One has been increasing its presence in local communities with the goal of helping customers in a way that is convenient to them. Through drop-in sessions, the mobile Electricity Discovery Centre and opening customer service offices in London, Markham and Sudbury, customer service staff have assisted over 2,500 customers in nearly 30 communities.

On October 24, 2017, Hydro One supported the launch of the Affordability Fund, a relief program paid for by the Province of Ontario and administered by Hydro One. This unique program will allow Hydro One, along with other local distribution companies, to provide customers who do not qualify for low-income conservation programs with the ability to access energy efficient home improvements, such as block heater timers, appliances and insulation.

Hydro One continues to be recognized as a leading utility by industry associations and national organizations. In late September 2017, the Canadian Council for Aboriginal Business awarded Hydro One bronze standing in its Progressive Aboriginal Relations (PAR) program. The honour recognizes the Company's commitment to fostering and strengthening its relationships with Indigenous Canadians and promoting prosperity in the communities they call home.

In September 2017, Hydro One received the Leader of the Year Award from the Ontario Energy Association. This prestigious award recognizes outstanding industry leadership and significant accomplishments. The association cited Hydro One's major cultural and corporate transformation, execution of the successful IPO, growth into the U.S. Pacific Northwest with the acquisition of Avista Corporation, and focus on exceptional customer service.

Mergers and Acquisitions Update

On September 14, 2017, Hydro One and Avista Corporation filed applications requesting regulatory approval of the proposed merger of the two companies that was announced on July 19, 2017. The applications have been filed with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the U.S. Federal Energy Regulatory Commission, requesting approval of the transaction on or before August 14, 2018. Together with Avista Corporation, Hydro One is currently in the process of responding to data requests from staff from the commissions and various other parties. Filing of these applications is an important milestone in the proposed transaction to bring together Hydro One and Avista Corporation. The merger will over time provide the companies with increased opportunities for innovation, research and development, and efficiencies by extending the use of technology, best practices, and business processes over a broader customer base and a broader set of infrastructure between the two companies. On October 2, 2017, Avista Corporation filed the preliminary proxy with the U.S. Securities and Exchange Commission for shareholder approval of the merger. Required filings with a number of other agencies will be made in the coming months, including the U.S. Federal Communications Commission, and the Committee on Foreign Investment in the United States.

Common Share Dividends

Following the conclusion of the third quarter, on November 9, 2017, the Company declared a quarterly cash dividend to common shareholders of $0.22 per share to be paid on December 29, 2017 to shareholders of record on December 12, 2017.

Supplemental Segment Information

	Three months ended September 30,		Nine months ended September 30,	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Revenues				
Transmission	471	444	1,199	1,211
Distribution	1,040	1,249	3,317	3,687
Other	11	13	35	40
Total revenues	**1,522**	**1,706**	**4,551**	**4,938**
Revenues, net of purchased power				
Transmission	471	444	1,199	1,211
Distribution	365	379	1,104	1,118
Other	11	13	35	40
Total revenues, net of purchased power	**847**	**836**	**2,338**	**2,369**
Income (loss) before financing charges and taxes				
Transmission	271	252	594	642
Distribution	114	126	369	390
Other	(24)	3	(50)	(19)
Total income before financing charges and taxes	**361**	**381**	**913**	**1,013**
Capital investments				
Transmission	240	241	701	714
Distribution	138	181	427	502
Other	2	2	8	4
Total capital investments	**380**	**424**	**1,136**	**1,220**
Assets placed in-service				
Transmission	120	224	367	449
Distribution	172	158	482	451
Other	2	1	10	6
Total assets placed in-service	**294**	**383**	**859**	**906**

This press release should be read in conjunction with the Company's third quarter 2017 Consolidated Financial Statements and Management's Discussion and Analysis (MD&A). These statements and MD&A together with additional information about Hydro One, including the full year 2016 Consolidated Financial Statements and Management's Discussion and Analysis, can be accessed at www.HydroOne.com/Investors and www.sedar.com.

Quarterly Investment Community Teleconference

The Company's third quarter 2017 results teleconference with the investment community will be held on November 10, 2017 at 8 a.m. ET, a webcast of which will be available at www.HydroOne.com/Investors. Members of the financial community wishing to ask questions during the call should dial 1-855-716-2690 prior to the scheduled start time and request access to Hydro One's third quarter 2017 results call, conference ID 90923670 (international callers may dial 1-440-996-5689). Media and other interested parties are welcome to participate on a listen-only basis. A webcast of the teleconference will be available at the same link following the call. Additionally, investors should note that from time to time Hydro One management presents at brokerage sponsored investor conferences. Most often, but not always, these conferences are webcast by the hosting brokerage firm, and when they are webcast, links are made available on Hydro One's website at www.HydroOne.com/Investors and are posted generally at least two days before the conference.

About Hydro One Limited

We are Ontario's largest electricity transmission and distribution provider with more than 1.3 million valued customers, $25 billion in assets and annual revenues of over $6.5 billion. Our team of 5,500 skilled and dedicated employees proudly and safely serves suburban, rural and remote communities across Ontario through our 30,000 circuit km high-voltage transmission and 123,000 circuit km primary distribution networks. Hydro One is committed to the communities we serve, and has been rated as the top utility in Canada for its corporate citizenship, sustainability, and diversity initiatives. We are one of only five utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association. We also provide advanced broadband telecommunications services on a wholesale basis utilizing our extensive fibre optic network. Hydro One Limited's common shares are listed on the Toronto Stock Exchange (TSX: H).

For More Information

For more information about everything Hydro One, please visit www.HydroOne.com where you can find additional information including links to securities filings, historical financial reports, and information about the Company's governance practices, corporate social responsibility, customer solutions, and further information about its business.

Forward-Looking Statements and Information

This press release may contain "forward-looking information" within the meaning of applicable securities laws. Such information includes, but is not limited to, statements related to: growth; transformation; customer service; community relations; performance; reliability; productivity; operational improvements; ongoing and planned investments, projects and initiatives; the OEB's transmission rates decision and its anticipated impacts; dividends; the Affordability Fund; and the acquisition of Avista Corporation. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance or actions and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One's filings with the securities regulatory authorities in Canada, which are available on SEDAR at www.sedar.com. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking information, except as required by law.

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The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the three and nine months ended September 30, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the three and nine months ended September 30, 2017, based on information available to management as of November 9, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

	Three months ended September 30			Nine months ended September 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Revenues	1,522	1,706	(10.8%)	4,551	4,938	(7.8%)
Purchased power	675	870	(22.4%)	2,213	2,569	(13.9%)
Revenues, net of purchased power[1]	847	836	1.3%	2,338	2,369	(1.3%)
Operation, maintenance and administration costs	277	264	4.9%	822	782	5.1%
Depreciation and amortization	209	191	9.4%	603	574	5.1%
Financing charges	114	98	16.3%	320	292	9.6%
Income tax expense	23	44	(47.7%)	73	110	(33.6%)
Net income attributable to common shareholders of Hydro One	**219**	**233**	**(6.0%)**	**503**	**593**	**(15.2%)**
Basic earnings per common share (EPS)	$0.37	$0.39	(5.1%)	$0.85	$1.00	(15.0%)
Diluted EPS	$0.37	$0.39	(5.1%)	$0.84	$0.99	(15.2%)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	$0.40	$0.39	2.6%	$0.88	$1.00	(12.0%)
Diluted Adjusted EPS[1]	$0.40	$0.39	2.6%	$0.88	$0.99	(11.1%)
Net cash from operating activities	442	510	(13.3%)	1,193	1,182	0.9%
Funds from operations (FFO)[1]	385	430	(10.5%)	1,177	1,149	2.4%
Capital investments	380	424	(10.4%)	1,136	1,220	(6.9%)
Assets placed in-service	294	383	(23.2%)	859	906	(5.2%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,857	22,991	(9.3%)	19,801	21,115	(6.2%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,226	6,621	(6.0%)	19,046	19,784	(3.7%)

	2017	2016
Debt to capitalization ratio[2]	53.0%	52.6%

[1] See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been presented at September 30, 2017 and December 31, 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

For the nine months ended September 30, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	48%	1%

At September 30, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	52%	35%	13%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the quarter ended September 30, 2017 of $219 million is a decrease of $14 million or 6.0% from the prior year. Significant influences on net income included:

- milder weather in 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand, and a decrease in distribution revenues due to lower energy consumption. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher transmission revenues driven by Ontario Energy Board's (OEB) decision on the 2017-2018 transmission rates filing, including higher disposition of certain OEB-approved variance accounts, higher export service credits, and higher rate revenues;
- higher operation, maintenance and administration (OM&A) costs primarily resulting from higher consulting costs primarily related to the acquisition of Avista Corporation; partially offset by reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during the third quarter of 2017 compared to the third quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016, as well as the issuance of Convertible Debentures in August 2017.

Net income attributable to common shareholders for the nine months ended September 30, 2017 of $503 million is a decrease of $90 million or 15.2% from the prior year. In addition to factors noted above, net income for the nine months ended September 30, 2017 was also impacted by lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system (excluding this adjustment in 2016, the bad debt expense was relatively flat year-over-year) .

EPS

EPS was $0.37 and $0.85 in the three and nine months ended September 30, 2017, respectively, compared to EPS of $0.39 and $1.00 in the comparable periods last year. The decreases in EPS were driven by lower net income for the three and nine months ended September 30, 2017, as discussed above.

Adjusted EPS, which adjusts for costs related to the Avista Corporation acquisition, was $0.40 and $0.88 in the three and nine months ended September 30, 2017, respectively, compared to $0.39 and $1.00 in the comparable periods last year. The changes in Adjusted EPS were driven by lower net income for the three and nine months ended September 30, 2017, as discussed above but exclude the impact of costs related to the Avista Corporation acquisition. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

	Three months ended September 30			Nine months ended September 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Transmission	471	444	6.1%	1,199	1,211	(1.0%)
Distribution	1,040	1,249	(16.7%)	3,317	3,687	(10.0%)
Other	11	13	(15.4%)	35	40	(12.5%)
Total revenues	1,522	1,706	(10.8%)	4,551	4,938	(7.8%)
Transmission	471	444	6.1%	1,199	1,211	(1.0%)
Distribution, net of purchased power	365	379	(3.7%)	1,104	1,118	(1.3%)
Other	11	13	(15.4%)	35	40	(12.5%)
Total revenues, net of purchased power	847	836	1.3%	2,338	2,369	(1.3%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,857	22,991	(9.3%)	19,801	21,115	(6.2%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,226	6,621	(6.0%)	19,046	19,784	(3.7%)

<u>Transmission Revenues</u>

Transmission revenues increased by 6.1% for the third quarter primarily due to the following:

- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, including higher disposition of certain OEB-approved variance accounts, higher export service credits, and higher rate revenues; and
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016; partially offset by

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%.

The decrease in transmission revenues for the nine months ended September 30, 2017 of 1.0% was mainly the result of similar factors as noted above, with lower peak demand and transmission rates more than offsetting increased revenues driven by the OEB's decision on the 2017-2018 transmission rates filing and the acquisition of Hydro One Sault Ste. Marie.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, decreased by 3.7% and 1.3% for the third quarter and nine months ended September 30, 2017, respectively. During the third quarter and year-to-date, lower energy consumption resulting from milder weather in 2017 was partially offset by increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	95	96	(1.0%)	296	284	4.2%
Distribution	149	160	(6.9%)	447	445	0.4%
Other	33	8	312.5%	79	53	49.1%
	277	264	4.9%	822	782	5.1%

Transmission OM&A Costs

Transmission OM&A costs for the quarter ended September 30, 2017 were comparable to prior year, and were impacted by:

- lower support services costs;
- lower volume of vegetation management work; and
- higher volume of stations and overhead maintenance work due to increased demand.

The increase of 4.2% for the nine months ended September 30, 2017, was primarily due to:

- additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016; and
- higher volume of environmental management program work; partially offset by
- lower volume of vegetation management work.

Distribution OM&A Costs

The decrease of 6.9% in distribution OM&A costs for the quarter ended September 30, 2017 was primarily due to:

- lower volume of vegetation management work;
- lower consulting costs; and
- lower support services costs; partially offset by
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the quarter.

Distribution OM&A costs for the nine months ended September 30, 2017 were comparable to prior year, and were primarily impacted by:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year);
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the quarter; and
- lower volume of vegetation management work.

Other OM&A Costs

The increase in other OM&A costs for the quarter and nine months ended September 30, 2017 was driven by higher consulting costs primarily related to the acquisition of Avista Corporation.

Financing Charges

The increase of $16 million or 16.3% in financing charges for the third quarter of 2017 was primarily due to the following:

- an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during the third quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense related to the Convertible Debentures issued in August 2017.

The increase of $28 million or 9.6% in financing charges for the nine months ended September 30, 2017 was the result of similar factors as noted above, and was partially offset by a decrease in interest expense on short-term notes payable mainly due to a lower weighted average balance in 2017, as well as a decrease in the weighted average interest rate for short-term notes.

Income Tax Expense

The effective tax rate for the three and nine months ended September 30, 2017 was 9.3% and 12.3%, respectively, compared to 15.5% and 15.3% for the three and nine months ended September 30, 2016, respectively. The decreases in income tax expense of $21 million and $37 million for the three and nine months ended September 30, 2017, respectively, were primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 9, 2017	March 14, 2017	March 31, 2017	$0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$0.22	131
August 8, 2017	September 12, 2017	September 29, 2017	$0.22	131
				387

Following the conclusion of the third quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
November 9, 2017	December 12, 2017	December 29, 2017	$0.22	131

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS)*	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015
Revenues	1,522	1,371	1,658	1,614	1,706	1,546	1,686	1,522
Purchased power	675	649	889	858	870	803	896	786
Revenues, net of purchased power	847	722	769	756	836	743	790	736
Net income to common shareholders	219	117	167	128	233	152	208	143
Basic EPS	$0.37	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35	$0.26
Diluted EPS	$0.37	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35	$0.26
Basic Adjusted EPS[1]	$0.40	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35	$0.24[2]
Diluted Adjusted EPS[1]	$0.40	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35	$0.24[2]

[1] See section "Non-GAAP Measures" for description of Adjusted EPS.

[2] For the quarter ended December 31, 2015, the basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which assumed that the total number of common shares outstanding was 595,000,000.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-service

The following table presents Hydro One's assets placed in-service during the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	120	224	(46.4%)	367	449	(18.3%)
Distribution	172	158	8.9%	482	451	6.9%
Other	2	1	100.0%	10	6	66.7%
Total assets placed in-service	294	383	(23.2%)	859	906	(5.2%)

Transmission Assets Placed In-service

Transmission assets placed in-service decreased by $104 million or 46.4% during the third quarter of 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in the third quarter of 2016; and
- a larger number of cumulative sustainment investments placed in-service in the third quarter of 2016, including the breaker replacement project at Richview transmission station, the asset replacement project at Gerrard transmission station, and the transformer replacement at Brant transmission station.

Transmission assets placed in-service decreased by $82 million or 18.3% during the nine months ended September 30, 2017 primarily due to factors noted above, partially offset by the following:

- a larger number of cumulative sustainment investments that were placed in-service in the first half of 2017, including the asset replacement project at Aylmer transmission station and the station reconfiguration project at Goderich transmission station; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-service

Distribution assets placed in-service increased by $14 million or 8.9% during the third quarter of 2017 primarily due to the following:

- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017;
- higher volume of subdivision connections due to increased demand; and
- higher volume of service equipment purchases; partially offset by
- timing of distribution station refurbishments and spare transformer purchases.

Distribution assets placed in-service increased by $31 million or 6.9% during the nine months ended September 30, 2017 primarily due to the following:

- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017;
- higher volume of subdivision connections due to increased demand; and
- higher volume of service equipment purchases; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during the first half of 2016; and
- lower volume of fleet and work equipment purchases.

Capital Investments

The following table presents Hydro One's capital investments during the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission						
Sustaining	189	180	5.0%	548	542	1.1%
Development	32	44	(27.3%)	108	123	(12.2%)
Other	19	17	11.8%	45	49	(8.2%)
	240	241	(0.4%)	701	714	(1.8%)
Distribution						
Sustaining	63	96	(34.4%)	215	291	(26.1%)
Development	53	62	(14.5%)	162	152	6.6%
Other	22	23	(4.3%)	50	59	(15.3%)
	138	181	(23.8%)	427	502	(14.9%)
Other	2	2	0.0%	8	4	100.0%
Total capital investments	380	424	(10.4%)	1,136	1,220	(6.9%)

Transmission Capital Investments

Transmission capital investments decreased by $1 million or 0.4% during the third quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- timing of work related to the Clarington Transmission Station project; and
- lower volume of transmission station refurbishments and component replacements work; partially offset by
- higher volume of overhead lines and component refurbishments and replacements.

Transmission capital investments decreased by $13 million or 1.8% during the nine months ended September 30, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete;
- lower volume of transmission station refurbishments and component replacements work; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- timing and substantial completion of major development projects including the Holland, Hawthorne, and Leamington transmission stations; and
- higher volume of overhead lines and component refurbishments and replacements.

Distribution Capital Investments

Distribution capital investments decreased by $43 million or 23.8% during the third quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of work within station refurbishment programs;
- lower volume of distribution lines sustainment work;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of work on storm damage and emergency power restorations; and
- lower volume of wood pole replacements.

Distribution capital investments decreased by $75 million or 14.9% during the nine months ended September 30, 2017 primarily due to factors noted above, and were also impacted by

- lower volume of work within station refurbishment programs;
- lower volume of wood pole replacements;
- lower volume of distribution lines sustainment work;
- lower volume of fleet and work equipment purchases; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at September 30, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$46 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$216 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$6 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	—
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$100 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$79 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$46 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$38 million

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2017 to 2021. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. These estimates differ from the prior year disclosures for 2017 and 2018 transmission capital investments, representing annual decreases of $126 million for 2017 and $122 million for 2018. These decreases reflect the OEB's focus on planning practices and the pacing of Sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2021 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by business segment:

(millions of dollars)	2017	2018	2019	2020	2021
Transmission	960	1,010	1,217	1,278	1,486
Distribution	648	647	771	735	749
Other	12	9	8	6	8
Total capital investments	**1,620**	**1,666**	**1,996**	**2,019**	**2,243**

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by category:

(millions of dollars)	2017	2018	2019	2020	2021
Sustainment	1,089	1,103	1,219	1,327	1,546
Development	334	340	484	487	490
Other[1]	197	223	293	205	207
Total capital investments	**1,620**	**1,666**	**1,996**	**2,019**	**2,243**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Cash provided by operating activities	442	510	1,193	1,182
Cash provided by financing activities	529	38	506	48
Cash used in investing activities	(382)	(414)	(1,127)	(1,184)
Increase in cash and cash equivalents	589	134	572	46

Cash provided by operating activities

Cash from Operating Activities decreased by $68 million during the third quarter of 2017 primarily due to lower net income and changes in accrual balances, partially offset by decreased energy-related receivables as a result of lower revenues in 2017 primarily reflecting lower commodity and global adjustment prices initiated by the Province of Ontario's (Province) Fair Hydro Plan and lower consumption reflecting mild weather.

Cash from Operating Activities increased by $11 million year-to-date primarily due to factors noted above, as well as changes in regulatory variance and deferral accounts that impact revenue.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the three or nine months ended September 30, 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $1,232 million and $2,810 million from the issuance of short-term notes in the three and nine months ended September 30, 2017, respectively, compared to $940 million and $2,435 million received in the three and nine months ended September 30, 2016, respectively.
- During the three and nine months ended September 30, 2017, the Company issued $513 million of convertible debentures, gross of $27 million financing costs, compared to no convertible debenture issuances in the three and nine months ended September 30, 2016.

Uses of cash

- Dividends paid in the three and nine months ended September 30, 2017 were $135 million and $400 million, respectively, compared to dividends of $129 million and $466 million paid in the three and nine months ended September 30, 2016, respectively.
- The Company repaid $1,053 million and $2,385 million of short-term notes in the three and nine months ended September 30, 2017, respectively, compared to $770 million and $2,808 million repaid in the three and nine months ended September 30, 2016, respectively.
- The Company repaid $1 million of long-term debt in the three and nine months ended September 30, 2017, compared to long-term debt of $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $32 million and $71 million lower in the third quarter and year-to-date 2017, respectively, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At September 30, 2017, Hydro One Inc. had $894 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company and Hydro One Inc. have revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At September 30, 2017, the Company's long-term debt in the principal amount of $10,670 million included $10,523 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $147 million held by Hydro One Sault Ste. Marie. At September 30, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at September 30, 2017, had an average term to maturity of approximately 15.1 years and a weighted average coupon rate of 4.3%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province. See "Other Developments - Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures. The Convertible Debentures instalment receipts trade on the Toronto Stock Exchange under the ticker symbol "H.IR". The Convertible Debentures were sold as part of Hydro One's acquisition financing strategy to acquire Avista Corporation (see section Other Developments - Avista Corporation Purchase agreement), which includes the issuance of $1,540 million of Hydro One common shares and US$2.6 billion of Hydro One debt. The Convertible Debentures were sold to satisfy the equity component of the acquisition financing strategy.

To mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed by the issuance of Convertible Debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. The forward rate includes a deal-contingent fee that could range from $26 million to $43 million, based on the date the contract is settled. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed anytime up to March 31, 2019. The balance of the Avista Corporation acquisition will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge.

At September 30, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

On July 19, 2017, Standard & Poor's Rating Services (S&P) revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

On July 19, 2017, S&P and Moody's Investors Service revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

September 30, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,670	602	2,134	1,106	6,828
Long-term debt – interest payments	7,831	442	811	725	5,853
Convertible debentures - principal repayments[1]	513	—	—	—	513
Convertible debentures - interest payments	106	70	36	—	—
Short-term notes payable	894	894	—	—	—
Pension contributions[2]	172	75	97	—	—
Environmental and asset retirement obligations	223	26	54	69	74
Outsourcing agreements	247	118	118	9	2
Operating lease commitments	45	12	20	10	3
Long-term software/meter agreement	61	17	34	7	3
Total contractual obligations	20,762	2,256	3,304	1,926	13,276
Other commercial commitments *(by year of expiry)*					
Credit facilities[3]	2,550	—	—	2,550	—
Letters of credit[4]	165	165	—	—	—
Guarantees[5]	325	325	—	—	—
Total other commercial commitments	3,040	490	—	2,550	—

[1] The Company expects that the Convertible Debentures will be converted to common shares upon closing of the Avista Corporation acquisition.

[2] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017, 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[3] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

[4] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, an $8 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[5] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Filed in October 2017
	2018	8.78% (F)	$11,148 million	Approved in September 2017	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017[1]	To be filed in 2018 Q3
	2019	8.78% (F)	$8,050 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	8.78% (F)	$8,478 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	8.78% (F)	$9,037 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	8.78% (F)	$9,437 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7, 2017, Hydro One Networks filed an update to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks Inc.'s (Hydro One Networks) 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the OEB's decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax to the Ontario Electricity Financial Corporation (OEFC) Regime to the Federal Tax Regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. The OEB proposed a basis for sharing a portion of the tax savings resulting from the deferred tax asset with ratepayers by reducing the amount of cash taxes approved for recovery in Hydro One Networks' 2017-2018 transmission rates. On November 9, 2017, the OEB issued a Decision and Order that modified the portion of the tax savings that should be shared with ratepayers. This proposed methodology would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same methodology for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an impairment of Hydro One Networks' distribution deferred income tax regulatory asset of up to approximately $370 million.

In October 2017, the Company filed a Motion to Review and Vary the Decision (Motion) and filed an appeal with the Divisional Court of Ontario (Appeal). The Motion seeks allocation of the full amount of future tax savings from the Deferred Tax Asset of $2,595 million to shareholders; a recovery of $5 million in 2018 for allowance for funds used during construction relating to the Niagara Reinforcement Project; and the recovery of approximately $1 million related to costs for the Ombudsman's Office. With respect to the Deferred Tax Assets, in both the Motion and Appeal, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The outcome of the Motion to Review and Vary as well as the Appeal are uncertain. If the decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application). The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

B2M LP

On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017, and as such, Hydro One is not required to file a Draft Rate Order for 2017.

Hydro One Sault Ste. Marie

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Sault Ste. Marie's 2017 transmission rates application, denying the requested revenue requirement for 2017. Hydro One Sault Ste. Marie's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure, a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that it plans to file a Leave to Construct application to construct the East-West Tie Line Project.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan and First Nations Rate Assistance Program came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations Rate Assistance Program, and to receive the credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $900 million as at December 31, 2016) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Common Share Offering

On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly holds approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Pension Plan

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and projected levels of pensionable earnings, the estimated total employer annual pension contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million and $71 million, respectively. The estimated 2017 annual employer contributions have decreased by approximately $17 million from $105 million based on improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals and the Power Workers' Union to facilitate the insourcing of these services effective March 1, 2018.

Exemptive Relief

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion, an all-cash transaction. Avista Corporation is an energy company primarily involved in regulated transmission, distribution and generation of energy, headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger, which is expected to occur in the second half of 2018, is subject to Avista Corporation common shareholder and certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. In addition, on the same date, Avista Corporation filed the preliminary proxy with the Securities and Exchange Commission related to shareholder approval of the Merger. Required filings with a number of other agencies will be made in the coming months.

Convertible Debenture Offering

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company and its wholly-owned subsidiary, 2587264 Ontario Inc., completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures represented by installment receipts (Debenture Offering). See section "Liquidity and Financing Strategy".

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Litigation Relating to the Merger

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and name as defendants Avista Corporation and its directors; Sharpenter also names Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits allege that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. The class actions are consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuits are not material to Hydro One.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Net cash from operating activities	442	510	1,193	1,182
Changes in non-cash balances related to operations	(52)	(73)	1	(12)
Preferred share dividends	(4)	(4)	(13)	(14)
Distributions to noncontrolling interest	(1)	(3)	(4)	(7)
FFO	385	430	1,177	1,149

Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs related to the Avista Corporation acquisition from net income. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it eliminates the impact of acquisition-related costs and provides users with a comparative basis to evaluate the operations of the Company.

	Three months ended September 30		Nine months ended September 30	
	2017	2016	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	219	233	503	593
Costs related to acquisition of Avista Corporation *(millions of dollars)*	18	—	21	—
Adjusted net income attributable to common shareholders *(millions of dollars)*	237	233	524	593
Weighted average number of shares				
Basic	595,386,308	595,000,000	595,254,201	595,000,000
Effect of dilutive stock-based compensation plans	2,132,142	2,108,392	1,971,557	1,627,531
Diluted	597,518,450	597,108,392	597,225,758	596,627,531
Adjusted EPS				
Basic	$0.40	$0.39	$0.88	$1.00
Diluted	$0.40	$0.39	$0.88	$0.99

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Revenues	1,522	1,706	4,551	4,938
Less: Purchased power	675	870	2,213	2,569
Revenues, net of purchased power	847	836	2,338	2,369

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Distribution revenues	1,040	1,249	3,317	3,687
Less: Purchased power	675	870	2,213	2,569
Distribution revenues, net of purchased power	365	379	1,104	1,118

FFO, basic and diluted Adjusted EPS, and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 49.9% ownership at September 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three and nine months ended September 30, 2017 and 2016:

(millions of dollars)		Three months ended September 30		Nine months ended September 30	
Related Party	**Transaction**	**2017**	**2016**	**2017**	**2016**
Province	Dividends paid	69	91	231	359
IESO	Power purchased	276	460	1,169	1,505
	Revenues for transmission services	390	434	1,124	1,185
	Amounts related to electricity rebates	181	—	321	—
	Distribution revenues related to rural rate protection	61	31	185	94
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	24	24
	Funding received related to Conservation and Demand Management programs	18	15	44	39
OPG	Power purchased	2	1	7	4
	Revenues related to provision of construction and equipment maintenance services	1	1	2	3
	Costs expensed related to the purchase of services	—	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	—	1	1
OEB	OEB fees	2	2	6	9
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	—	—	2

RISK FACTORS

Risk Factors Relating to the Merger

Hydro One may fail to complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated (including with respect to the consideration to be paid in respect of the common stock of Avista Corporation) or at all. The completion of the Merger is subject to receipt of Avista Corporation shareholder approval and satisfaction of other approval conditions, including certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US $103 million.

The purchase price could increase

Avista Corporation is a public company and its directors owe fiduciary duties to Avista Corporation shareholders, which may require them to consider competing offers to purchase the common stock of Avista Corporation as alternatives to the Merger. The Merger Agreement preserves the ability of the directors of Avista Corporation to accept an alternative or competing offer in certain circumstances if such offer constitutes a superior proposal. If a superior proposal to acquire Avista Corporation is made, and if the superior proposal results in Avista Corporation's board of directors making a recommendation change to Avista Corporation's shareholders which is adverse to Hydro One, Avista Corporation is required to negotiate in good faith with Hydro One regarding any revisions to the Merger Agreement, which could result in an increase to the purchase price of the Merger or changes to other terms and conditions of the Merger.

Length of time required to complete the Merger is unknown

As described above under "Hydro One Limited may fail to complete the Merger", the closing of the Merger is subject to the receipt of required Avista Corporation shareholder approval and certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Company's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavorable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Company could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required Avista Corporation shareholder approval and regulatory approvals and satisfying the other required closing conditions.

Foreign exchange risk

The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a significant portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger. This risk has been partially mitigated through entering into a foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars which is contingent upon the closing of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional demands will be placed on Hydro One as a result of the Merger

As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of funding that would be used to fund the Merger may not be available

Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company.

There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates that could affect the underlying cost of any financing may affect the expected accretion of the Merger.

Hydro One expects to incur significant Merger-related expenses

Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approval. Additional unanticipated costs may be incurred.

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will substantially increase its amount of indebtedness following the Merger

After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US $1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a *pro forma* basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (assuming no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One will substantially increase its amount of indebtedness following the Merger and such increased indebtedness may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering could result in a downgrade of Hydro One's credit ratings

The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Reputational and Public Opinion Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the Company's 2016 annual MD&A.

Together, disclosure controls and procedures and internal control over financial reporting make up the systems that provide internal control over reporting and disclosure. These systems include policies and procedures designed to enable the reliability and timeliness of information disclosed by the Company. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior finance executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until a new Chief Financial Officer is appointed. There have been no other significant changes in the design of the Company's internal control over financial reporting during the nine months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – September 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed during the fourth quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; collective agreements; Inergi outsourcing and customer service operations arrangements; future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; non-GAAP measures; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Convertible Debentures; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the Company's financing strategy and foreign currency hedging relating to the acquisition of Avista Corporation; litigation relating to the Merger; the risk that the Company may fail to complete the Merger; the risk that the purchase price of Avista Corporation could increase; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; and reputational and public opinion risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;

- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three and nine months ended September 30, 2017 and 2016

	Three months ended September 30		Nine months ended September 30	
(millions of Canadian dollars, except per share amounts)	2017	2016	2017	2016
Revenues				
Distribution (includes related party revenues of $69 (2016 – $39) and $209 (2016 – $120) for the three and nine months ended September 30, respectively) *(Note 22)*	1,040	1,249	3,317	3,687
Transmission (includes related party revenues of $390 (2016 – $435) and $1,125 (2016 – $1,187) for the three and nine months ended September 30, respectively) *(Note 22)*	471	444	1,199	1,211
Other	11	13	35	40
	1,522	1,706	4,551	4,938
Costs				
Purchased power (includes related party costs of $278 (2016 – $461) and $1,177 (2016 – $1,510) for the three and nine months ended September 30, respectively) *(Note 22)*	675	870	2,213	2,569
Operation, maintenance and administration *(Note 22)*	277	264	822	782
Depreciation and amortization *(Note 5)*	209	191	603	574
	1,161	1,325	3,638	3,925
Income before financing charges and income taxes	361	381	913	1,013
Financing charges	114	98	320	292
Income before income taxes	247	283	593	721
Income taxes *(Note 6)*	23	44	73	110
Net income	**224**	**239**	**520**	**611**
Other comprehensive income	—	—	1	—
Comprehensive income	**224**	**239**	**521**	**611**
Net income attributable to:				
Noncontrolling interest	1	2	4	4
Preferred shareholders	4	4	13	14
Common shareholders	219	233	503	593
	224	**239**	**520**	**611**
Comprehensive income attributable to:				
Noncontrolling interest	1	2	4	4
Preferred shareholders	4	4	13	14
Common shareholders	219	233	504	593
	224	**239**	**521**	**611**
Earnings per common share *(Note 20)*				
Basic	$0.37	$0.39	$0.85	$1.00
Diluted	$0.37	$0.39	$0.84	$0.99
Dividends per common share declared *(Note 19)*	$0.22	$0.21	$0.65	$0.76

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At September 30, 2017 and December 31, 2016

(millions of Canadian dollars)	September 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	622	50
Accounts receivable *(Note 7)*	590	838
Due from related parties	294	158
Other current assets *(Note 8)*	119	102
	1,625	1,148
Property, plant and equipment *(Note 9)*	19,734	19,140
Other long-term assets:		
Regulatory assets	3,147	3,145
Deferred income tax assets	1,048	1,235
Intangible assets (net of accumulated amortization – $357; 2016 – $330)	359	349
Goodwill	327	327
Other assets	5	7
	4,886	5,063
Total assets	**26,245**	**25,351**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 13)*	894	469
Long-term debt payable within one year *(Notes 13, 15)*	602	602
Accounts payable and other current liabilities *(Note 11)*	959	945
Due to related parties	6	147
	2,461	2,163
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 13, 15)*	10,067	10,078
Convertible debentures *(Notes 14, 15)*	486	—
Regulatory liabilities	127	209
Deferred income tax liabilities	65	60
Other long-term liabilities *(Note 12)*	2,815	2,752
	13,560	13,099
Total liabilities	**16,021**	**15,262**
Contingencies and Commitments (Notes 24, 25)		
Subsequent Events (Notes 10, 27)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 18)*	5,631	5,623
Preferred shares *(Note 18)*	418	418
Additional paid-in capital	44	34
Retained earnings	4,066	3,950
Accumulated other comprehensive loss	(7)	(8)
Hydro One shareholders' equity	10,152	10,017
Noncontrolling interest	50	50
Total equity	**10,202**	**10,067**
	26,245	**25,351**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the nine months ended September 30, 2017 and 2016

Nine months ended September 30, 2017 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	—	—	—	516	—	516	3	519
Other comprehensive income	—	—	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	(3)	(3)
Dividends on preferred shares	—	—	—	(13)	—	(13)	—	(13)
Dividends on common shares	—	—	—	(387)	—	(387)	—	(387)
Common shares issued	8	—	(8)	—	—	—	—	—
Stock-based compensation	—	—	18	—	—	18	—	18
September 30, 2017	**5,631**	**418**	**44**	**4,066**	**(7)**	**10,152**	**50**	**10,202**

Nine months ended September 30, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	607	—	607	3	610
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(5)	(5)
Dividends on preferred shares	—	—	—	(14)	—	(14)	—	(14)
Dividends on common shares	—	—	—	(452)	—	(452)	—	(452)
Stock-based compensation	—	—	18	—	—	18	—	18
September 30, 2016	**5,623**	**418**	**28**	**3,947**	**(8)**	**10,008**	**50**	**10,058**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE LIMITED
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and nine months ended September 30, 2017 and 2016

(millions of Canadian dollars)	Three months ended September 30 2017	Three months ended September 30 2016	Nine months ended September 30 2017	Nine months ended September 30 2016
Operating activities				
Net income	224	239	520	611
Environmental expenditures	(7)	(5)	(19)	(15)
Adjustments for non-cash items:				
Depreciation and amortization (excluding asset removal costs)	187	170	537	506
Regulatory assets and liabilities	(32)	(6)	92	(28)
Deferred income taxes	17	33	55	90
Other	1	6	9	6
Changes in non-cash balances related to operations *(Note 23)*	52	73	(1)	12
Net cash from operating activities	442	510	1,193	1,182
Financing activities				
Long-term debt issued	—	—	—	1,350
Long-term debt repaid	—	—	(1)	(450)
Short-term notes issued	1,232	940	2,810	2,435
Short-term notes repaid	(1,053)	(770)	(2,385)	(2,808)
Convertible debentures issued *(Note 14)*	513	—	513	—
Dividends paid	(135)	(129)	(400)	(466)
Distributions paid to noncontrolling interest	(1)	(3)	(4)	(7)
Other *(Note 14)*	(27)	—	(27)	(6)
Net cash from financing activities	529	38	506	48
Investing activities				
Capital expenditures *(Note 23)*				
Property, plant and equipment	(358)	(399)	(1,071)	(1,156)
Intangible assets	(24)	(15)	(57)	(43)
Acquisitions	—	(3)	—	(3)
Capital contributions received	—	—	9	15
Other	—	3	(8)	3
Net cash used in investing activities	(382)	(414)	(1,127)	(1,184)
Net change in cash and cash equivalents	589	134	572	46
Cash and cash equivalents, beginning of period	33	6	50	94
Cash and cash equivalents, end of period	**622**	**140**	**622**	**140**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). At September 30, 2017, the Province of Ontario (Province) held approximately 49.9% (December 31, 2016 – 70.1%) of the common shares of Hydro One.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) for interim financial statements and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – September 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed during the fourth quarter of 2017. The Company is on track for implementation of this standard by the effective date.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. BUSINESS COMBINATION

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion, an all-cash transaction. Avista Corporation is an energy company primarily involved in regulated transmission, distribution and generation of energy, headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger, which is expected to occur in the second half of 2018, is subject to Avista Corporation common shareholder and certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. In addition, on the same date, Avista Corporation filed the preliminary proxy with the Securities and Exchange Commission related to shareholder approval of the Merger. Required filings with a number of other agencies will be made in the coming months.

5. DEPRECIATION AND AMORTIZATION

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Depreciation of property, plant and equipment	164	151	473	450
Asset removal costs	22	21	66	68
Amortization of intangible assets	16	14	45	41
Amortization of regulatory assets	7	5	19	15
	209	191	603	574

6. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	Nine months ended September 30	
(millions of dollars)	2017	2016
Income taxes at statutory rate	157	191
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(38)	(41)
Pension contributions in excess of pension expense	(11)	(13)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(12)
Interest capitalized for accounting but deducted for tax purposes	(13)	(14)
Environmental expenditures	(6)	(5)
Prior years' adjustments	(4)	1
Other	(3)	1
Net temporary differences	(87)	(83)
Net permanent differences	3	2
Total income taxes	73	110
Effective income tax rate	12.3%	15.3%

7. ACCOUNTS RECEIVABLE

(millions of dollars)	September 30, 2017	December 31, 2016
Accounts receivable – billed	291	431
Accounts receivable – unbilled	330	442
Accounts receivable, gross	621	873
Allowance for doubtful accounts	(31)	(35)
Accounts receivable, net	590	838

The following table shows the movements in the allowance for doubtful accounts for the nine months ended September 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Nine months ended September 30, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	18	37
Additions to allowance for doubtful accounts	(14)	(11)
Allowance for doubtful accounts – ending	(31)	(35)

8. OTHER CURRENT ASSETS

(millions of dollars)	September 30, 2017	December 31, 2016
Regulatory assets	58	37
Materials and supplies	19	19
Prepaid expenses and other assets	42	46
	119	102

9. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	September 30, 2017	December 31, 2016
Property, plant and equipment	28,312	27,687
Less: accumulated depreciation	(10,261)	(9,935)
	18,051	17,752
Construction in progress	1,518	1,234
Future use land, components and spares	165	154
	19,734	19,140

10. REGULATORY ASSETS AND LIABILITIES

Deferred Income Tax Regulatory Asset

On September 28, 2017, the Ontario Energy Board (OEB) issued its Decision and Order on Hydro One Networks Inc.'s (Hydro One Networks) 2017 and 2018 transmission rates revenue requirements (Decision).

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax to the Ontario Electricity Financial Corporation (OEFC) Regime to the Federal Tax Regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. The OEB proposed a basis for sharing a portion of the tax savings resulting from the deferred tax asset with ratepayers by reducing the amount of cash taxes approved for recovery in Hydro One Networks' 2017-2018 transmission rates. On November 9, 2017, the OEB issued a Decision and Order that modified the portion of the tax savings that should be shared with ratepayers. This proposed methodology would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same methodology for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an impairment of Hydro One Networks' distribution deferred income tax regulatory asset of up to approximately $370 million. In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The outcome of the Motion to Review and Vary as well as the Appeal are uncertain. If the decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	September 30, 2017	December 31, 2016
Accounts payable	158	181
Accrued liabilities	603	659
Accrued interest	140	105
Regulatory liabilities	58	—
	959	945

12. OTHER LONG-TERM LIABILITIES

(millions of dollars)	September 30, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,702	1,641
Pension benefit liability	899	900
Environmental liabilities *(Note 17)*	174	177
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	31	25
	2,815	2,752

13. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At September 30, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million included Hydro One's credit facilities of $250 million and Hydro One Inc.'s credit facilities of $2.3 billion. In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

Long-Term Debt

The following table presents long-term debt outstanding at September 30, 2017 and December 31, 2016:

(millions of dollars)	September 30, 2017	December 31, 2016
Hydro One Inc. long-term debt *(a)*	10,523	10,523
HOSSM long-term debt *(b)*	179	184
	10,702	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[1]	(9)	(2)
Less: Deferred debt issuance costs	(38)	(40)
Total long-term debt	10,669	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,067	10,078

[1] The unrealized mark-to-market net gain relates to Hydro One Inc.'s $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. long-term debt

At September 30, 2017, long-term debt of $10,523 million (December 31, 2016 - $10,523 million) was outstanding under Hydro One Inc.'s MTN Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At September 30, 2017, $1.2 billion remained available for issuance until January 2018. During the nine months ended September 30, 2017, no long-term debt was issued or repaid under the MTN Program (2016 - $1,350 million issued and $450 million repaid).

(b) Hydro One Sault Ste. Marie. (HOSSM) long-term debt

At September 30, 2017, long-term debt related to HOSSM was $179 million (December 31, 2016 - $184 million), with a face value of $147 million. During the nine months ended September 30, 2017, $1 million of HOSSM long-term debt was repaid.

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.6
3 years	1,153	2.3
4 years	503	1.9
5 years	603	3.2
	3,842	2.9
6 – 10 years	633	3.5
Over 10 years	6,195	5.2
	10,670	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
Remainder of 2017	141
2018	426
2019	402
2020	384
2021	370
	1,723
2022-2026	1,703
2027+	4,405
	7,831

14. CONVERTIBLE DEBENTURES

(millions of dollars, except as otherwise noted)	
Maturity date	September 30, 2027
Coupon rate	4.00%
Conversion price per common share	$ 21.40
Carrying value at December 31, 2016	—
Receipt of Initial Instalment, net of deferred financing costs	486
Amortization of deferred financing costs	—
Carrying value at September 30, 2017	486
Face value at September 30, 2017	513

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) is payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred deferred financing costs of $27 million, which are being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures will mature on September 30, 2027 and bear interest at an annual rate of 4.00% per $1,000 principal amount of Convertible Debentures until and including the Final Instalment Date, after which the interest rate will be 0%. If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of the Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date (Make-Whole Payment). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

Based on the Initial Instalment of $333 per $1,000 principal amount of Convertible Debentures and the expectation that the Final Instalment Date will occur on a day that is after the first anniversary of the closing of the Debenture Offering, the effective annual yield to and including the Final Instalment Date is 12%, and the effective annual yield thereafter is 0%. The interest expense recorded for the three and nine months ended September 30, 2017 is $9 million.

At the option of the holders and provided that payment of the Final Instalment has been made, each Convertible Debenture will be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures. The conversion feature meets the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized. Between the time the contingency is resolved and the Final Instalment Date, the Company will recognize approximately $92 million of interest expense associated with amortization of the BCF.

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that the Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Avista Corporation will not be satisfied; (ii) termination of the acquisition agreement; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders on or before April 30, 2019. Upon any such redemption, the Company will pay for each Convertible Debenture (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the selling debentureholder on behalf of the holder of the instalment receipt in satisfaction of the final instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in common shares, which will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At September 30, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at September 30, 2017 and December 31, 2016 are as follows:

	September 30, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	10,128	11,328	10,132	11,462
Long-term debt, including current portion	10,669	11,869	10,680	12,010

Fair Value Measurements of Derivative Instruments

At September 30, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At September 30, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At September 30, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at September 30, 2017 and December 31, 2016 is as follows:

September 30, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	622	622	622	—	—
	622	622	622	—	—
Liabilities:					
Short-term notes payable	894	894	894	—	—
Long-term debt, including current portion	10,669	11,869	—	11,869	—
Convertible debentures	486	587	587	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
	12,058	13,359	1,490	11,869	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on September 29, 2017 (last business day in September 2017), as posted on the Toronto Stock Exchange.

There were no transfers between any of the fair value levels during the nine months ended September 30, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

<u>Market Risk</u>

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three and nine months ended September 30, 2017 and 2016.

The Company is exposed to foreign exchange fluctuations related to the expected acquisition of Avista Corporation as the purchase price is denominated in US dollars. This risk has been partially mitigated through entering into a deal-contingent foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars subsequent to the end of the third quarter (see note 27). The balance of the Avista Corporation acquisition purchase price will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and nine months ended September 30, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At September 30, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At September 30, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At September 30, 2017, the Company's provision for bad debts was $31 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At September 30, 2017, approximately 6% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At September 30, 2017 and December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At September 30, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

16. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million, and $71 million, respectively, based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Employer contributions made during the nine months ended September 30, 2017 were $67 million (2016 – $83 million).

The following tables provide the components of the net periodic benefit costs for the three and nine months ended September 30, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Three months ended September 30 *(millions of dollars)*	**2017**	**2016**	**2017**	**2016**
Current service cost	36	36	12	11
Interest cost	76	77	17	17
Expected return on plan assets, net of expenses[1]	(110)	(109)	—	—
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	28	31	30
Charged to results of operations[2]	10	13	14	13

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Nine months ended September 30 *(millions of dollars)*	**2017**	**2016**	**2017**	**2016**
Current service cost	109	108	36	32
Interest cost	228	231	51	51
Expected return on plan assets, net of expenses[1]	(331)	(326)	—	—
Actuarial loss amortization	60	72	6	6
Net periodic benefit costs	66	85	93	89
Charged to results of operations[2]	31	38	41	37

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three and nine months ended September 30, 2017, pension costs of $22 million (2016 – $29 million) and $68 million (2016 – $86 million), respectively, were attributed to labour, of which $10 million (2016 – $13 million) and $31 million (2016 – $38 million), respectively, were charged to operations, and $12 million (2016 – $16 million) and $37 million (2016 – $48 million) respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

17. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the nine months ended September 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Nine months ended September 30, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	6	8
Expenditures	(19)	(20)
Revaluation adjustment	11	9
Environmental liabilities – ending	202	204
Less: current portion	(28)	(27)
	174	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	September 30, 2017	December 31, 2016
Undiscounted environmental liabilities	214	224
Less: discounting environmental liabilities to present value	(12)	(20)
Discounted environmental liabilities	202	204

Future expenditures have been discounted using rates ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At September 30, 2017, the estimated undiscounted future environmental expenditures were as follows:

(millions of dollars)	
2017 [1]	8
2018	25
2019	25
2020	30
2021	37
Thereafter	89
	214

[1] The amounts disclosed represent amounts for the period from October 1, 2017 to December 31, 2017.

18. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At September 30, 2017, the Company had 595,386,599 (December 31, 2016 – 595,000,000) common shares issued and outstanding.

The following table presents the changes to common shares during the nine months ended September 30, 2017. There was no movement in common shares during the year ended December 31, 2016.

(number of shares)	
Common shares – December 31, 2016	595,000,000
Common shares issued – share grants *(a)*	371,611
Common shares issued – LTIP *(b)*	13,714
Common shares issued – LTIP *(c)*	1,274
Common shares – September 30, 2017	595,386,599

(a) On April 1, 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the Power Workers' Union Share Grant Plan.

(b) On May 31, 2017, Hydro One issued from treasury 13,714 common shares in accordance with provisions of the Long-term Incentive Plan (LTIP).

(c) On July 21, 2017, Hydro One issued from treasury 1,274 common shares to in accordance with provisions of the LTIP.

Secondary Common Share Offering

On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Following completion of the Offering, the Province directly holds approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At September 30, 2017 and December 31, 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At September 30, 2017 and December 31, 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

19. DIVIDENDS

During the three months ended September 30, 2017, preferred share dividends in the amount of $4 million (2016 – $4 million) and common share dividends in the amount of $131 million (2016 – $125 million) were declared and paid.

During the nine months ended September 30, 2017, preferred share dividends in the amount of $13 million (2016 – $14 million) and common share dividends in the amount of $387 million (2016 – $452 million) were declared and paid.

20. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the Long-term Incentive Plan (LTIP), which are calculated using the treasury stock method.

	Three months ended September 30		Nine months ended September 30	
	2017	2016	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	219	233	503	593
Weighted average number of shares				
Basic	595,386,308	595,000,000	595,254,201	595,000,000
Effect of dilutive stock-based compensation plans	2,132,142	2,108,392	1,971,557	1,627,531
Diluted	597,518,450	597,108,392	597,225,758	596,627,531
EPS				
Basic	$0.37	$0.39	$0.85	$1.00
Diluted	$0.37	$0.39	$0.84	$0.99

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS until conditions for closing the Avista Corporation acquisition are met.

21. STOCK-BASED COMPENSATION

Share Grant Plans

A summary of share grant activity under the Share Grant Plans during the three and nine months ended September 30, 2017 and 2016 is presented below:

	Three months ended September 30		Nine months ended September 30	
(number of share grants)	2017	2016	2017	2016
Share grants outstanding – beginning	4,962,804	5,412,354	5,334,415	5,412,354
Vested[1]	—	—	(371,611)	—
Share grants outstanding – ending	4,962,804	5,412,354	4,962,804	5,412,354

[1] On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

Directors' Deferred Share Units (DSU) Plan

During the three and nine months ended September 30, 2017 and 2016, the Company granted awards under its Directors' DSU Plan, as follows:

	Three months ended September 30		Nine months ended September 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	141,553	59,205	99,083	20,525
DSUs granted	22,504	18,922	64,974	57,602
DSUs outstanding – ending	164,057	78,127	164,057	78,127

At September 30, 2017, a liability of $4 million (December 31, 2016 – $2 million) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.72 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Company's Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the three and nine months ended September 30, 2017 and 2016, the Company granted awards under its Management DSU Plan, as follows:

	Three months ended September 30		Nine months ended September 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	67,583	—	—	—
DSUs granted	657	—	68,240	—
DSUs outstanding – ending	68,240	—	68,240	—

At September 30, 2017, a liability of $2 million (December 31, 2016 – $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.72 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three and nine months ended September 30, 2017 and 2016, the Company granted awards under its LTIP, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled, as follows:

	PSUs		RSUs	
Three months ended September 30 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	443,095	124,120	409,645	149,120
Units granted	35,790	103,270	21,040	101,820
Units vested	(609)	—	(609)	—
Units forfeited	(9,036)	(1,730)	(7,676)	(1,730)
Units outstanding – ending	469,240	225,660	422,400	249,210

	PSUs		RSUs	
Nine months ended September 30 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	230,600	—	254,150	—
Units granted	303,240	227,390	239,990	250,940
Units vested	(609)	—	(14,079)	—
Units forfeited	(63,991)	(1,730)	(57,661)	(1,730)
Units outstanding – ending	469,240	225,660	422,400	249,210

The grant date total fair value of the awards granted during the three and nine months ended September 30, 2017 was $1 million and $13 million (2016 – $5 million and $12 million), respectively. The compensation expense recognized by the Company relating to LTIP awards during the three and nine months ended September 30, 2017 was $2 million and $5 million (2016 – $1 million and $1 million), respectively.

22. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 49.9% ownership at September 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

(millions of dollars)		Three months ended September 30		Nine months ended September 30	
Related Party	**Transaction**	**2017**	**2016**	**2017**	**2016**
Province	Dividends paid	69	91	231	359
IESO	Power purchased	276	460	1,169	1,505
	Revenues for transmission services	390	434	1,124	1,185
	Amounts related to electricity rebates	181	—	321	—
	Distribution revenues related to rural rate protection	61	31	185	94
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	24	24
	Funding received related to Conservation and Demand Management programs	18	15	44	39
OPG	Power purchased	2	1	7	4
	Revenues related to provision of construction and equipment maintenance services	1	1	2	3
	Costs expensed related to the purchase of services	—	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	—	1	1
OEB	OEB fees	2	2	6	9
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	—	—	2

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

23. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Accounts receivable	50	(13)	241	(2)
Due from related parties	(38)	15	(136)	15
Materials and supplies	—	2	—	3
Prepaid expenses and other assets	9	17	6	(12)
Accounts payable	(10)	(6)	(9)	14
Accrued liabilities	(16)	(6)	(57)	18
Due to related parties	2	30	(141)	(103)
Accrued interest	37	19	35	24
Long-term accounts payable and other liabilities	(3)	(2)	(1)	2
Post-retirement and post-employment benefit liability	21	17	61	53
	52	73	(1)	12

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Capital investments in property, plant and equipment	(359)	(407)	(1,087)	(1,175)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	1	8	16	19
Cash outflow for capital expenditures – property, plant and equipment	(358)	(399)	(1,071)	(1,156)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Capital investments in intangible assets	(21)	(17)	(49)	(45)
Net change in accruals included in capital investments in intangible assets	(3)	2	(8)	2
Cash outflow for capital expenditures – intangible assets	(24)	(15)	(57)	(43)

Supplementary Information

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Net interest paid	89	89	308	291
Income taxes paid	3	10	11	25

24. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Litigation Relating to the Merger

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and name as defendants Avista Corporation and its directors; Sharpenter also names Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits allege that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. The class actions are consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuits are not material to Hydro One.

25. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

September 30, 2017 *(millions of dollars)*	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Outsourcing agreements	118	93	25	2	7	2
Long-term software/meter agreement	17	17	17	6	1	3
Operating lease commitments	12	9	11	5	5	3

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

September 30, 2017 *(millions of dollars)*	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Credit facilities	—	—	—	—	2,550	—
Letters of credit[1]	165	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, an $8 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

26. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended September 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	471	1,040	11	1,522
Purchased power	—	675	—	675
Operation, maintenance and administration	95	149	33	277
Depreciation and amortization	105	102	2	209
Income (loss) before financing charges and income taxes	271	114	(24)	361
Capital investments	240	138	2	380

Three months ended September 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	444	1,249	13	1,706
Purchased power	—	870	—	870
Operation, maintenance and administration	96	160	8	264
Depreciation and amortization	96	93	2	191
Income before financing charges and income taxes	252	126	3	381
Capital investments	241	181	2	424

Nine months ended September 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,199	3,317	35	4,551
Purchased power	—	2,213	—	2,213
Operation, maintenance and administration	296	447	79	822
Depreciation and amortization	309	288	6	603
Income (loss) before financing charges and income taxes	594	369	(50)	913
Capital investments	701	427	8	1,136

Nine months ended September 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,211	3,687	40	4,938
Purchased power	—	2,569	—	2,569
Operation, maintenance and administration	284	445	53	782
Depreciation and amortization	285	283	6	574
Income (loss) before financing charges and income taxes	642	390	(19)	1,013
Capital investments	714	502	4	1,220

Total Assets by Segment:

(millions of dollars)	September 30, 2017	December 31, 2016
Transmission	13,505	13,071
Distribution	9,321	9,379
Other	3,419	2,901
Total assets	26,245	25,351

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

27. SUBSEQUENT EVENTS

Dividends

On November 9, 2017, preferred share dividends in the amount of $5 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

Foreign Exchange Forward Contract

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. The forward rate includes a deal-contingent fee that could range from $26 million to $43 million, based on the date the contract is settled. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. This agreement is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures. The contract can be executed anytime up to March 31, 2019. This contract is an economic hedge and does not qualify for hedge accounting. It has been classified as an undesignated contract.

Repayment of Long-term Debt

On October 18, 2017, Hydro One Inc. repaid $600 million of maturing long-term debt notes (MTN Series 13 notes) under its MTN Program.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (the Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the three months ended March 31, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which vary from those of the US. This MD&A provides information for the three months ended March 31, 2017, based on information available to management as of May 3, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Three months ended March 31 *(millions of dollars, except as otherwise noted)*	**2017**	**2016**	**Change**
Revenues	1,646	1,672	(1.6%)
Purchased power	889	896	(0.8%)
Revenues, net of purchased power	757	776	(2.4%)
Operation, maintenance and administration costs	264	248	6.5%
Depreciation and amortization	193	188	2.7%
Financing charges	103	96	7.3%
Income tax expense	26	32	(18.8%)
Net income attributable to common shareholder of Hydro One	**170**	**211**	**(19.4%)**
Basic earnings per common share (EPS)	$1,195	$1,485	(19.4%)
Diluted EPS	$1,195	$1,485	(19.4%)
Net cash from operating activities	459	369	24.4%
Funds from operations (FFO)[1]	390	383	1.8%
Capital investments	347	378	(8.2%)
Assets placed in-service	228	158	44.3%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,795	20,555	(3.7%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,967	7,045	(1.1%)

	March 31, 2017	**December 31, 2016**
Debt to capitalization ratio[2]	53.0%	52.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

For the three months ended March 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	**Distribution**	**Other**
Percentage of Company's total revenues, net of purchased power	48%	52%	–

At March 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	**Distribution**	**Other**
Percentage of Company's total assets	52%	37%	11%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholder for the quarter ended March 31, 2017 of $170 million is a decrease of $41 million or 19.4% from the prior year. Significant influences on net income included:

- milder weather in the first quarter of 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand, and a decrease in distribution revenues, as energy consumption declined. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher operation, maintenance and administration (OM&A) costs primarily resulting from lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- increased financing charges primarily due to increased weighted average long-term debt outstanding during the first quarter of 2017 compared to the first quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

Revenues

Three months ended March 31 *(millions of dollars, except as otherwise noted)*	**2017**	**2016**	**Change**
Transmission	367	386	(4.9%)
Distribution	1,279	1,286	(0.5%)
	1,646	1,672	(1.6%)
Transmission volumes:			
Average monthly Ontario 60-minute peak demand *(MW)*	19,795	20,555	(3.7%)
Distribution volumes:			
Electricity distributed to Hydro One customers *(GWh)*	6,967	7,045	(1.1%)

<u>Transmission Revenues</u>

Transmission revenues decreased by 4.9% for the first quarter primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased Ontario Energy Board (OEB)-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; partially offset by
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

<u>Distribution Revenues</u>

Distribution revenues decreased by 0.5% for the first quarter primarily due to the following:

- lower power costs from generators that are passed on to customers; and
- lower energy consumption resulting from milder weather in 2017; partially offset by
- increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**	**Change**
Transmission	106	101	5.0%
Distribution	147	143	2.8%
Other	11	4	175.0%
	264	248	6.5%

<u>Transmission OM&A Costs</u>

The increase of 5.0% in transmission OM&A costs for the quarter ended March 31, 2017 was primarily due to higher consulting costs related to efficiency studies and additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

Distribution OM&A Costs

The increase of 2.8% in distribution OM&A costs for the quarter ended March 31, 2017 was primarily due to the following:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- higher consulting costs related to customer initiatives; partially offset by
- lower emergency power and storm restoration costs in 2017 as last year's costs were elevated by an ice storm in March 2016.

Other OM&A Costs

The increase in other OM&A costs for the quarter ended March 31, 2017 was primarily due to higher consulting costs related to strategy development and higher corporate management costs.

Financing Charges

The increase of $7 million or 7.3% in financing charges for the quarter ended March 31, 2017 was primarily due to an increase in interest expense on long-term debt driven by an increase in the weighted average long-term debt balance outstanding during the first quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016. This was partially offset by a decrease in the weighted average interest rate for long-term debt.

Income Tax Expense

The effective tax rate for the three months ended March 31, 2017 was 13.2% compared to 13.1% for the three months ended March 31, 2016. The decrease in income tax expense of $6 million for the quarter ended March 31, 2017 was primarily due to lower income before taxes, partially offset by changes in temporary differences included in the rate setting process such as capital cost allowance in excess of depreciation and pension contributions in excess of pension expense.

QUARTERLY RESULTS OF OPERATIONS

Quarter ended (*millions of dollars, except EPS*)	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015
Revenues	1,646	1,604	1,693	1,533	1,672	1,513	1,645	1,563
Purchased power	889	858	870	803	896	786	856	838
Revenues, net of purchased power	757	746	823	730	776	727	789	725
Net income to common shareholder	170	131	233	155	211	132	188	131
Basic and diluted EPS	$1,195	$921	$1,638	$1,086	$1,485	$1,036	$1,869	$1,313

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

The following table presents Hydro One's assets placed in-service during the three months ended March 31, 2017 and 2016:

Three months ended March 31 (*millions of dollars*)	2017	2016	Change
Transmission	82	51	60.8%
Distribution	146	107	36.4%
Total assets placed in-service	**228**	**158**	**44.3%**

Transmission assets placed in-service increased by $31 million or 60.8% during the first quarter of 2017 primarily due to the timing of a larger number of sustainment investments that were placed in-service early in 2017, including the station refurbishment projects at Richview, Nepean, Hinchinbrooke, Bruce A, and Strathroy transmission stations.

Distribution assets placed in-service increased by $39 million or 36.4% during the first quarter of 2017 primarily due to the following:

- the completion of an operation center in Bolton in February 2017;
- timing of distribution station refurbishments and spare transformer purchases as work and vendor deliveries were deferred from 2016; and
- higher volume of trouble calls and power restoration work.

The following table presents Hydro One's capital investments during the three months ended March 31, 2017 and 2016:

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**	**Change**
Transmission			
Sustaining	162	181	(10.5%)
Development	37	40	(7.5%)
Other	10	14	(28.6%)
	209	235	(11.1%)
Distribution			
Sustaining	72	86	(16.3%)
Development	47	39	20.5%
Other	19	18	5.6%
	138	143	(3.5%)
Total capital investments	**347**	**378**	**(8.2%)**

Transmission Capital Investments

Transmission capital investments decreased by $26 million or 11.1% during the first quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of sustainment project work;
- timing of work related to the Clarington Transmission Station project;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; and
- completion of the Guelph Area Transmission Refurbishment project; partially offset by
- continued work on major local area supply network development projects, such as the Holland Transmission Station and the Hawthorne Transmission Station.

Distribution Capital Investments

Distribution capital investments decreased by $5 million or 3.5% during the first quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of wood pole replacements;
- lower volume of work within station refurbishment programs; and
- decreased storm restoration work compared to prior year mainly as a result of the ice storm in March 2016; partially offset by
- higher volume of work in new connections and upgrades due to increased demand; and
- higher volume of emergency power restorations.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at March 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$16 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$203 million
East-West Tie Station Expansion	Northern Ontario	Station expansion	2020	$166 million	–
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	–
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$90 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$102 million	$72 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2020	$95 million	$25 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$35 million

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**
Cash provided by operating activities	459	369
Cash provided by (used in) financing activities	(160)	137
Cash used in investing activities	(347)	(355)
Increase (decrease) in cash and cash equivalents	**(48)**	**151**

Cash provided by operating activities

The increase in cash provided by operating activities is primarily due to decreased energy-related receivables as a result of lower revenues in the first quarter of 2017 primarily reflecting a lower average Ontario peak demand and lower energy consumption due to milder weather in the first quarter of 2017.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the first quarter of 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $572 million from issuance of short-term notes in the first quarter of 2017, compared to $731 million received in the first quarter of 2016.

Uses of cash

- In the first quarter of 2017, the Company made a return of stated capital in the amount of $147 million, compared to a return of stated capital of $226 million made in the first quarter of 2016.
- The Company repaid $590 million of short-term notes, compared to $1,267 million repaid in the first quarter of 2016.
- The Company repaid no long-term debt in the first quarter of 2017 compared to $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $24 million lower in the first quarter of 2017, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's commercial paper program, and bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At March 31, 2017, Hydro One had $451 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, Hydro One has revolving bank credit facilities totalling $2.3 billion maturing in 2021. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At March 31, 2017, the Company's long-term debt in the principal amount of $10,671 million included $10,523 million long-term debt issued under its Medium Term Note (MTN) Program and long-term debt in the principal amount of $148 million held by Hydro One Sault Ste. Marie. At March 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at March 31, 2017, had an average term to maturity of approximately 15.6 years and a weighted average coupon rate of 4.3%.

At March 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

March 31, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,671	602	1,484	1,756	6,829
Long-term debt – interest payments	8,058	456	826	749	6,027
Short-term notes payable	451	451	–	–	–
Pension contributions[1]	188	103	85	–	–
Environmental and asset retirement obligations	228	28	52	66	82
Outsourcing agreements	327	152	163	6	6
Operating lease commitments	38	10	15	11	2
Long-term software/meter agreement	68	16	34	14	4
Total contractual obligations	20,029	1,818	2,659	2,602	12,950
Other commercial commitments *(by year of expiry)*					
Credit facilities	2,300	–	–	2,300	–
Letters of credit[2]	169	169	–	–	–
Guarantees[3]	325	325	–	–	–
Total other commercial commitments	2,794	494	–	2,300	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017 and 2018 minimum pension contributions are based on an actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings.

[2] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $12 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[3] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision pending
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Cost-of-service	OEB decision pending
Mergers Acquisitions Amalgamations and Divestitures			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,554 million	Filed in May 2016	To be filed in 2017 Q2
	2018	8.78% (F)	$11,226 million	Filed in May 2016	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Filed in December 2016
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Filed in December 2016	Filed in December 2016
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017	To be filed in 2017 Q4
	2019	8.78% (F)	$8,049 million	Filed in March 2017	To be filed in 2018 Q4
	2020	8.78% (F)	$8,477 million	Filed in March 2017	To be filed in 2019 Q4
	2021	8.78% (F)	$9,035 million	Filed in March 2017	To be filed in 2020 Q4
	2022	8.78% (F)	$9,435 million	Filed in March 2017	To be filed in 2021 Q4

Hydro One Networks

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in the first half of 2018, and that new rates will be effective on January 1, 2018.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced its Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Company's recommendation to provide a credit on the delivery charge for on-reserve First Nations customers is expected to be implemented. The Province of Ontario (Province) also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements are also planned to the existing Ontario Electricity Support Program.

Starting in the summer of 2017, a reduction of 25% is expected to be introduced on electricity bills for typical Ontario residents. This reduction is expected to include the 8% rebate from the *Ontario Rebate for Electricity Consumers Act, 2016*. The RRRP and First Nations Rate Assistance program delivery charge credit is expected to be funded from Provincial revenues, reducing regulatory charges for Ontario ratepayers. Funding for the Ontario Electricity Support Program is expected to be increased by 50%, and it is expected that the changes to the RRRP will result in distribution cost reductions of about 10% for an average low-density and medium-density Hydro One customer, consuming 1,150 kWh and 900 kWh, respectively. These changes, once implemented, are not expected to have an impact on the net revenues of the Company.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Three months ended March 31 *(millions of dollars)*	**2017**	**2016**
Net cash from operating activities	459	369
Changes in non-cash balances related to operations	(69)	17
Distributions to noncontrolling interest	–	(3)
FFO	**390**	**383**

FFO is not a recognized measure under US GAAP and does not have a standardized meaning prescribed by US GAAP. FFO is therefore unlikely to be directly comparable to similar measures presented by other companies. FFO should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is the majority shareholder of Hydro One Limited. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), OEB, and Hydro One Telecom are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc. and subsequent to the acquisition by Alectra Inc. is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three months ended March 31, 2017 and 2016:

		Three months ended March 31	
		2017	**2016**
Related Party	**Transaction**	*(millions of dollars)*	
IESO	Power purchased	651	710
	Revenues for transmission services	369	376
	Amounts related to electricity rebates	77	–
	Distribution revenues related to rural rate protection	61	31
	Distribution revenues related to the supply of electricity to remote northern communities	8	8
	Funding received related to Conservation and Demand Management programs	16	7
OPG	Power purchased	4	2
	Revenues related to provision of construction and equipment maintenance services	–	1
	Costs expensed related to the purchase of services	–	1
OEFC	Power purchased from power contracts administered by the OEFC	1	–
OEB	OEB fees	2	4
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	–	1
Hydro One Limited	Return of stated capital	147	226
	Dividends paid	2	2
	Stock-based compensation costs	6	5
Hydro One Telecom	Services received – costs expensed	6	6
	Services received – costs capitalized	–	3
	Revenues for services provided	1	–

INTERNAL CONTROLS OVER FINANCIAL REPORTING

There have been no changes in Hydro One's internal controls over financial reporting during the three months ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05	May 2014 – February 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is underway and will continue through to the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting rates and expected timing of decisions; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; future pension contributions and valuations; non-GAAP measures; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; and the Company's acquisitions, including Orillia Power Distribution Corporation. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One's parent corporation and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com, the US Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31 *(millions of Canadian dollars, except per share amounts)*	**2017**	**2016**
Revenues		
Distribution (includes $69 related party revenues; 2016 – $40) *(Note 19)*	1,279	1,286
Transmission (includes $370 related party revenues; 2016 – $377) *(Note 19)*	367	386
	1,646	1,672
Costs		
Purchased power (includes $656 related party costs; 2016 – $712) *(Note 19)*	889	896
Operation, maintenance and administration *(Note 19)*	264	248
Depreciation and amortization *(Note 4)*	193	188
	1,346	1,332
Income before financing charges and income taxes	300	340
Financing charges	103	96
Income before income taxes	197	244
Income taxes *(Note 5)*	26	32
Net income	**171**	**212**
Other comprehensive income	1	–
Comprehensive income	**172**	**212**
Net income attributable to:		
Noncontrolling interest	1	1
Common shareholder	170	211
	171	**212**
Comprehensive income attributable to:		
Noncontrolling interest	1	1
Common shareholder	171	211
	172	**212**
Earnings per common share *(Note 17)*		
Basic	$1,195	$1,485
Diluted	$1,195	$1,485
Dividends per common share declared *(Note 16)*	$14	$14

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At March 31, 2017 and December 31, 2016

(millions of Canadian dollars)	March 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	–	48
Accounts receivable *(Note 6)*	735	833
Due from related parties	281	224
Other current assets *(Note 7)*	94	97
	1,110	1,202
Property, plant and equipment *(Note 8)*	19,250	19,068
Other long-term assets:		
Regulatory assets	3,154	3,145
Deferred income tax assets	1,158	1,213
Intangible assets (net of accumulated amortization – $344; 2016 – $330)	347	349
Goodwill	327	327
Other assets	8	6
	4,994	5,040
Total assets	**25,354**	**25,310**
Liabilities		
Current liabilities:		
Bank indebtedness	7	–
Short-term notes payable *(Note 11)*	451	469
Long-term debt payable within one year *(Notes 11, 12)*	602	602
Accounts payable and other current liabilities *(Note 9)*	972	933
Due to related parties	222	253
	2,254	2,257
Long-term liabilities:		
Long-term debt (includes $549 measured at fair value; 2016 – $548) *(Notes 11, 12)*	10,080	10,078
Regulatory liabilities	211	209
Deferred income tax liabilities	61	60
Other long-term liabilities *(Note 10)*	2,784	2,765
	13,136	13,112
Total liabilities	**15,390**	**15,369**
Contingencies and Commitments (Notes 21, 22)		
Subsequent Events (Note 24)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 15)*	5,244	5,391
Retained earnings	4,655	4,487
Accumulated other comprehensive loss	(8)	(9)
Hydro One shareholder's equity	9,891	9,869
Noncontrolling interest	51	50
Total equity	**9,942**	**9,919**
	25,354	**25,310**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31, 2017 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,391	4,487	(9)	9,869	50	9,919
Net income	–	170	–	170	1	171
Other comprehensive income	–	–	1	1	–	1
Dividends on common shares	–	(2)	–	(2)	–	(2)
Return of stated capital	(147)	–	–	(147)	–	(147)
March 31, 2017	**5,244**	**4,655**	**(8)**	**9,891**	**51**	**9,942**

Three months ended March 31, 2016 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	–	211	–	211	1	212
Distributions to noncontrolling interest	–	–	–	–	(2)	(2)
Dividends on common shares	–	(2)	–	(2)	–	(2)
Return on stated capital	(226)	–	–	(226)	–	(226)
March 31, 2016	**5,774**	**3,968**	**(9)**	**9,733**	**51**	**9,784**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three months ended March 31, 2017 and 2016

Three months ended March 31 *(millions of Canadian dollars)*	**2017**	**2016**
Operating activities		
Net income	171	212
Environmental expenditures	(4)	(3)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	172	164
Regulatory assets and liabilities	31	(10)
Deferred income taxes	20	21
Other	–	2
Changes in non-cash balances related to operations *(Note 20)*	69	(17)
Net cash from operating activities	459	369
Financing activities		
Long-term debt issued	–	1,350
Long-term debt repaid	–	(450)
Short-term notes issued	572	731
Short-term notes repaid	(590)	(1,267)
Return of stated capital	(147)	(226)
Dividends paid	(2)	(2)
Distributions paid to noncontrolling interest	–	(3)
Change in bank indebtedness	7	10
Other	–	(6)
Net cash from (used in) financing activities	(160)	137
Investing activities		
Capital expenditures *(Note 20)*		
Property, plant and equipment	(332)	(357)
Intangible assets	(14)	(13)
Capital contributions received	7	15
Other	(8)	–
Net cash used in investing activities	(347)	(355)
Net change in cash and cash equivalents	(48)	151
Cash and cash equivalents, beginning of period	48	89
Cash and cash equivalents, end of period	**–**	**240**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05	May 2014 – February 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed its initial assessment and has identified relevant revenue streams. No quantitative determination has been made as a detailed assessment is underway and will continue through to the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. DEPRECIATION AND AMORTIZATION

Three months ended March 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	153	148
Asset removal costs	21	24
Amortization of intangible assets	15	13
Amortization of regulatory assets	4	3
	193	188

5. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Three months ended March 31 *(millions of dollars)*	2017	2016
Income taxes at statutory rate	52	65
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(11)	(14)
Pension contributions in excess of pension expense	(5)	(7)
Overheads capitalized for accounting but deducted for tax purposes	(4)	(4)
Interest capitalized for accounting but deducted for tax purposes	(4)	(5)
Environmental expenditures	(3)	(2)
Other	–	(1)
Net temporary differences	(27)	(33)
Net permanent differences	1	–
Total income taxes	26	32
Effective income tax rate	13.2%	13.1%

6. ACCOUNTS RECEIVABLE

(millions of dollars)	March 31, 2017	December 31, 2016
Accounts receivable – billed	432	427
Accounts receivable – unbilled	338	441
Accounts receivable, gross	770	868
Allowance for doubtful accounts	(35)	(35)
Accounts receivable, net	735	833

The following table shows the movements in the allowance for doubtful accounts for the three months ended March 31, 2017 and the year ended December 31, 2016:

(millions of dollars)	Three months ended March 31, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	6	37
Additions to allowance for doubtful accounts	(6)	(11)
Allowance for doubtful accounts – ending	(35)	(35)

7. OTHER CURRENT ASSETS

(millions of dollars)	March 31, 2017	December 31, 2016
Regulatory assets	35	37
Materials and supplies	19	19
Prepaid expenses and other assets	40	41
	94	97

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	March 31, 2017	December 31, 2016
Property, plant and equipment	27,743	27,523
Less: accumulated depreciation	(9,985)	(9,832)
	17,758	17,691
Construction in progress	1,330	1,223
Future use land, components and spares	162	154
	19,250	19,068

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	March 31, 2017	December 31, 2016
Accounts payable	169	177
Accrued liabilities	670	651
Accrued interest	130	105
Regulatory liabilities	3	–
	972	933

10. OTHER LONG-TERM LIABILITIES

(millions of dollars)	March 31, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,650	1,628
Pension benefit liability	894	900
Environmental liabilities *(Note 14)*	173	177
Due to related parties	32	26
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	26	25
	2,784	2,765

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One's committed revolving credit facilities totalling $2.3 billion.

Long-Term Debt

At March 31, 2017, $10,523 million long-term debt was outstanding under the Company's Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At March 31, 2017, $1.2 billion remained available for issuance until January 2018. In addition, at March 31, 2017, the Company had long-term debt of $184 million held by Hydro One Sault Ste. Marie.

The following table presents long-term debt outstanding at March 31, 2017 and December 31, 2016:

(millions of dollars)	March 31, 2017	December 31, 2016
Notes and debentures	10,707	10,707
Add: Net unamortized debt premiums	15	15
Add: Unrealized mark-to-market gain[1]	(1)	(2)
Less: Deferred debt issuance costs	(39)	(40)
Total long-term debt	10,682	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,080	10,078

[1] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $1 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

During the three months ended March 31, 2017, Hydro One did not issue (2016 – $1,350 million) long-term debt under the MTN Program, and made no repayments (2016 – $450 million) of long-term debt.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.4
3 years	503	1.5
4 years	1,153	2.5
5 years	603	3.2
	3,842	2.9
6 – 10 years	634	3.5
Over 10 years	6,195	5.2
	10,671	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
Remainder of 2017	369
2018	425
2019	402
2020	384
2021	370
	1,950
2022-2026	1,703
2027+	4,405
	8,058

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At March 31, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at March 31, 2017 and December 31, 2016 are as follows:

	March 31, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current portion				
$50 million of MTN Series 33 notes	50	50	50	50
$500 million MTN Series 37 notes	499	499	498	498
Other notes and debentures	10,133	11,556	10,132	11,462
	10,682	12,105	10,680	12,010

Fair Value Measurements of Derivative Instruments

At March 31, 2017, Hydro One had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One's fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At March 31, 2017, Hydro One had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At March 31, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at March 31, 2017 and December 31, 2016 is as follows:

March 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Bank indebtedness	7	7	7	–	–
Short-term notes payable	451	451	451	–	–
Long-term debt, including current portion	10,682	12,105	–	12,105	–
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	1	–	–
	11,141	12,564	459	12,105	–

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	48	48	48	–	–
	48	48	48	–	–
Liabilities:					
Short-term notes payable	469	469	469	–	–
Long-term debt, including current portion	10,680	12,010	–	12,010	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	–	–
	11,151	12,481	471	12,010	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the three months ended March 31, 2017 or year ended December 31, 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three months ended March 31, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three months ended March 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At March 31, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At March 31, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At March 31, 2017, the Company's provision for bad debts was $35 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At March 31, 2017, approximately 6% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At March 31, 2017 and December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At March 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017 and 2018 are approximately $105 million and $102 million, respectively, based on the actuarial valuation as at December 31, 2015 and projected levels of pensionable earnings. Employer contributions made during the three months ended March 31, 2017 were $28 million (2016 – $46 million).

The following table provides the components of the net periodic benefit costs for the three months ended March 31, 2017 and 2016:

Three months ended March 31 *(millions of dollars)*	Pension Benefits		Post-Retirement and Post-Employment Benefits	
	2017	2016	2017	2016
Current service cost	36	36	12	11
Interest cost	76	77	17	17
Expected return on plan assets, net of expenses[1]	(110)	(109)	–	–
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	28	31	30
Charged to results of operations[2]	13	22	14	13

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three months ended March 31, 2017, pension costs of $30 million (2016 – $50 million) were attributed to labour, of which $13 million (2016 – $22 million) was charged to operations and $17 million (2016 – $28 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

14. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the three months ended March 31, 2017 and the year ended December 31, 2016:

(millions of dollars)	Three months ended March 31, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	2	8
Expenditures	(4)	(20)
Revaluation adjustment	–	9
Environmental liabilities – ending	202	204
Less: current portion	29	27
	173	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	March 31, 2017	December 31, 2016
Undiscounted environmental liabilities	219	224
Less: discounting accumulated liabilities to present value	17	20
Discounted environmental liabilities	202	204

Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At March 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017[1]	22
2018	26
2019	25
2020	29
2021	36
Thereafter	81
	219

[1] The amounts disclosed represent amounts for the period from April 1, 2017 to December 31, 2017.

15. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At March 31, 2017 and December 31, 2016, the Company had 142,239 common shares issued and outstanding.

During the three months ended March 31, 2017, the Company returned stated capital of $147 million (2016 – $226 million).

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At March 31, 2017 and December 31, 2016, Hydro One had no issued and outstanding preferred shares.

16. DIVIDENDS

During the three months ended March 31, 2017, common share dividends in the amount of $2 million (2016 – $2 million) were declared and paid.

17. EARNINGS PER SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding during the three months ended March 31, 2017 was 142,239 (2016 – 142,239). There were no dilutive securities during the three months ended March 31, 2017 and 2016.

18. STOCK-BASED COMPENSATION

Management Deferred Share Units (DSU) Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

Three months ended March 31 *(number of DSUs)*	2017	2016
DSUs outstanding – January 1	–	–
DSUs granted	62,999	–
DSUs outstanding – March 31	62,999	–

At March 31, 2017, a liability of $2 million (December 31, 2016 – $nil), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $24.25 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three months ended March 31, 2017 and 2016, Hydro One Limited granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled in Hydro One Limited shares, as follows:

Three months ended March 31, 2017	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2017	228,890	252,440
Units granted	264,300	215,370
Units forfeited	(14,435)	(15,885)
Units outstanding – March 31, 2017	478,755	451,925

Three months ended March 31, 2016	Number of PSUs	Number of RSUs
Units outstanding – January 1, 2016	–	–
Units granted	124,120	149,120
Units outstanding – March 31, 2016	124,120	149,120

The grant date total fair value of the awards granted during the three months ended March 31, 2017 was $12 million (2016 – $7 million). The compensation expense recognized by the Company relating to LTIP awards during the three months ended March 31, 2017 was $1 million (2016 – $nil). At March 31, 2017, a liability of $4 million was recorded in long-term due to related parties on the Consolidated Balance Sheets.

19. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is the majority shareholder of Hydro One Limited. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), OEB, and Hydro One Telecom are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

		Three months ended March 31	
		2017	2016
Related Party	Transaction	*(millions of dollars)*	
IESO	Power purchased	651	710
	Revenues for transmission services	369	376
	Amounts related to electricity rebates	77	–
	Distribution revenues related to rural rate protection	61	31
	Distribution revenues related to the supply of electricity to remote northern communities	8	8
	Funding received related to Conservation and Demand Management programs	16	7
OPG	Power purchased	4	2
	Revenues related to provision of construction and equipment maintenance services	–	1
	Costs expensed related to the purchase of services	–	1
OEFC	Power purchased from power contracts administered by the OEFC	1	–
OEB	OEB fees	2	4
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	–	1
Hydro One Limited	Return of stated capital	147	226
	Dividends paid	2	2
	Stock-based compensation costs	6	5
Hydro One Telecom	Services received – costs expensed	6	6
	Services received – costs capitalized	–	3
	Revenues for services provided	1	–

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Three months ended March 31 *(millions of dollars)*	2017	2016
Accounts receivable	91	(77)
Due from related parties	(57)	21
Materials and supplies	–	1
Prepaid expenses and other assets	(1)	(7)
Accounts payable	(1)	6
Accrued liabilities	19	(7)
Due to related parties	(31)	3
Accrued interest	25	24
Long-term accounts payable and other liabilities	2	–
Post-retirement and post-employment benefit liability	22	19
	69	(17)

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Three months ended March 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(334)	(366)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	2	9
Capital expenditures – property, plant and equipment	(332)	(357)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Three months ended March 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(13)	(12)
Net change in accruals included in capital investments in intangible assets	(1)	(1)
Capital expenditures – intangible assets	(14)	(13)

Supplementary Information

Three months ended March 31 *(millions of dollars)*	2017	2016
Net interest paid	88	80
Income taxes paid	4	8

21. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

22. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

March 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	152	93	70	2	4	6
Long-term software/meter agreement	16	17	17	13		4
Operating lease commitments	10	9	6	8	3	2

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

March 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	–	–	–	–	2,300	–
Letters of credit[1]	169	–	–	–	–	–
Guarantees[2]	325	–	–	–	–	–

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $12 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended March 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	367	1,279	–	1,646
Purchased power	–	889	–	889
Operation, maintenance and administration	106	147	11	264
Depreciation and amortization	101	92	–	193
Income (loss) before financing charges and income taxes	160	151	(11)	300
Capital investments	209	138	–	347

Three months ended March 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	386	1,286	–	1,672
Purchased power	–	896	–	896
Operation, maintenance and administration	101	143	4	248
Depreciation and amortization	95	93	–	188
Income (loss) before financing charges and income taxes	190	154	(4)	340
Capital investments	235	143	–	378

Total Assets by Segment:

(millions of dollars)	March 31, 2017	December 31, 2016
Transmission	13,166	13,083
Distribution	9,375	9,393
Other	2,813	2,834
Total assets	25,354	25,310

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. SUBSEQUENT EVENTS

Dividends and Return of Stated Capital

On May 3, 2017, common share dividends in the amount of $4 million were declared, and a return of stated capital in the amount of $129 million was approved.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (the Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the three and six months ended June 30, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which vary from those of the US. This MD&A provides information for the three and six months ended June 30, 2017, based on information available to management up to August 8, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

	Three months ended June 30			Six months ended June 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Revenues	1,361	1,533	(13.4%)	3,007	3,205	(6.6%)
Purchased power	649	803	(19.2%)	1,538	1,699	(9.5%)
Revenues, net of purchased power[1]	712	730	(2.5%)	1,469	1,506	(2.5%)
Operation, maintenance and administration costs	268	254	5.5%	532	502	6.0%
Depreciation and amortization	197	191	3.1%	390	379	2.9%
Financing charges	103	97	6.2%	206	193	6.7%
Income tax expense	22	32	(31.3%)	48	64	(25.0%)
Net income attributable to common shareholder of Hydro One	**120**	**155**	**(22.6%)**	**290**	**366**	**(20.8%)**
Basic earnings per common share (EPS)	$844	$1,086	(22.6%)	$2,039	$2,571	(20.8%)
Diluted EPS	$844	$1,086	(22.6%)	$2,039	$2,571	(20.8%)
Net cash from operating activities	266	283	(6.0%)	725	652	11.2%
Funds from operations (FFO)[1]	396	338	17.2%	786	721	9.0%
Capital investments	403	416	(3.1%)	750	794	(5.5%)
Assets placed in-service	329	360	(8.6%)	557	518	7.5%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	18,752	19,799	(5.3%)	19,273	20,177	(4.5%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	5,842	6,118	(4.5%)	12,820	13,163	(2.6%)

	June 30, 2017	December 31, 2016
Debt to capitalization ratio[2]	53.6%	52.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO and Revenues, net of purchased power..

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to non-controlling interest.

OVERVIEW

For the six months ended June 30, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	50%	50%	—%

At June 30, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	52%	37%	11%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the quarter ended June 30, 2017 of $120 million is a decrease of $35 million or 22.6% from the prior year. Significant influences on net income included:

- milder weather in the second quarter of 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher operation, maintenance and administration (OM&A) costs primarily resulting from higher storm restoration costs as a result of multiple storms in the second quarter of 2017;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during the second quarter of 2017 compared to the second quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

Net income attributable to common shareholders for the six months ended June 30, 2017 of $290 million is a decrease of $76 million or 20.8% from the prior year. In addition to factors noted above, net income for the six months ended June 30, 2017 was also impacted by the following:

- decrease in distribution revenues, due to lower energy consumption mainly resulting from milder weather in the first quarter of 2017;
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system (excluding this adjustment in 2016, the bad debt expense was relatively flat year-over-year);
- higher consulting costs; and
- higher storm restoration costs as a result of multiple storms in the second quarter of 2017, offset by lower emergency power and storm restoration costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016.

A delay in approval of the 2017-2018 transmission rates filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of the decision at that time.

Revenues

	Three months ended June 30			Six months ended June 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Transmission	363	381	(4.7%)	730	767	(4.8%)
Distribution	998	1,152	(13.4%)	2,277	2,438	(6.6%)
Total revenues	1,361	1,533	(11.2%)	3,007	3,205	(6.2%)
Transmission	363	381	(4.7%)	730	767	(4.8%)
Distribution, net of purchased power	349	349	—%	739	739	—%
Total revenues, net of purchased power	712	730	(2.5%)	1,469	1,506	(2.5%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	18,752	19,799	(5.3%)	19,273	20,177	(4.5%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	5,842	6,118	(4.5%)	12,820	13,163	(2.6%)

Transmission Revenues

Transmission revenues decreased by 4.7% for the second quarter primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased Ontario Energy Board (OEB)-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; partially offset by
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

The decrease in transmission revenues for the six months ended June 30, 2017 of 4.8% was mainly the result of similar factors as noted above.

A delay in approval of the 2017-2018 transmission rates filing has also impacted revenues, however Hydro One anticipates a decision in the near term. Hydro One anticipates the revised rates will be effective from January 1, 2017 and as a result would book the increased revenue up to the date of the decision at that time.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, for the second quarter and six months ended June 30, 2017 were consistent with prior year. During the second quarter and year-to-date, lower energy consumption resulting from a milder winter in 2017 was offset by increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	103	97	6.2%	209	198	5.6%
Distribution	154	146	5.5%	301	289	4.2%
Other	11	11	—%	22	15	46.7%
	268	254	5.5%	532	502	6.0%

Transmission OM&A Costs

The increase of 6.2% in transmission OM&A costs for the quarter ended June 30, 2017 was primarily due to higher volume of environmental management program work; and additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016.

The increase of 5.6% in transmission OM&A costs for the six months ended June 30, 2017 was primarily due to factors noted above.

Distribution OM&A Costs

The increase of 5.5% in distribution OM&A costs for the quarter ended June 30, 2017 was primarily due to higher storm restoration costs as a result of multiple storms in the second quarter of 2017.

The increase of 4.2% in distribution OM&A costs for the six months ended June 30, 2017 was impacted by:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year); and
- higher storm restoration costs as a result of multiple storms in the second quarter of 2017, offset by lower emergency power and storm restoration costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016.

Other OM&A Costs

The increase in other OM&A costs for the six months ended June 30, 2017 was primarily due to higher consulting costs primarily related to strategy development and higher corporate management costs in the first quarter of 2017.

Financing Charges

The increase of $6 million or 6.2% in financing charges for the second quarter of 2017 was primarily due to an increase in interest expense on long-term debt driven by an increase in the weighted average long-term debt balance outstanding during the first quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016. This was partially offset by a decrease in the weighted average interest rate for long-term debt.

The increase of $13 million or 6.7% in financing charges for the six months ended June 30, 2017 was the result of similar factors as noted above.

Income Tax Expense

The effective tax rate for the three and six months ended June 30, 2017 was 15.3% and 14.1%, respectively, compared to 17.0% and 14.8% for the three and six months ended June 30, 2016, respectively.

The decreases in income tax expense of $10 million and $16 million for the three and six months ended June 30, 2017, respectively, were primarily due to lower income before taxes in 2017.

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS)*	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015	Sep 30, 2015
Revenues	1,361	1,646	1,604	1,693	1,533	1,672	1,513	1,645
Purchased power	649	889	858	870	803	896	786	856
Revenues, net of purchased power	712	757	746	823	730	776	727	789
Net income to common shareholder	120	170	131	233	155	211	132	188
Basic and diluted EPS	$844	$1,195	$921	$1,638	$1,086	$1,485	$1,036	$1,869

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-service

The following table presents Hydro One's assets placed in-service during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	165	174	(5.2%)	247	225	9.8%
Distribution	164	186	(11.8%)	310	293	5.8%
Total assets placed in-service	329	360	(8.6%)	557	518	7.5%

Transmission Assets Placed In-service

Transmission assets placed in-service decreased by $9 million or 5.2% during the second quarter of 2017 primarily due to the following:

- two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in the second quarter of 2016; partially offset by
- a larger number of cumulative sustainment investments that were placed in-service in the second quarter of 2017, including the asset replacement project at Aylmer transmission station and the station reconfiguration project at Goderich transmission station; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Transmission assets placed in-service increased by $22 million or 9.8% during the six months ended June 30, 2017 primarily due to the timing of a larger number of sustainment investments that were placed in-service in the first quarter of 2017, including the station refurbishment projects at Richview, Nepean, Hinchinbrooke, Bruce A, and Strathroy transmission stations, that more than offset the decrease in transmission assets placed-in service in the second quarter of 2017 as noted above.

Distribution Assets Placed In-service

Distribution assets placed in-service decreased by $22 million or 11.8% during the second quarter of 2017 primarily due to the following:

- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service in the second quarter of 2016;
- lower volume of fleet and work equipment purchases; partially offset by
- the completion of the Move-to-Mobile project in June 2017.

Distribution assets placed in-service increased by $17 million or 5.8% during the six months ended June 30, 2017 primarily due to the completion of an operation center in Bolton in February 2017 and timing of distribution station refurbishment and spare transformer purchases in the first quarter of 2017 as work and vendor deliveries were deferred from 2016, that more than offset the decrease in distribution assets placed-in service in the second quarter of 2017 as noted above.

Capital Investments

The following table presents Hydro One's capital investments during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30			Six months ended June 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission						
Sustaining	197	181	8.8%	359	362	(0.8%)
Development	39	39	—%	76	79	(3.8%)
Other	16	18	(11.1%)	26	32	(18.8%)
	252	238	5.9%	461	473	(2.5%)
Distribution						
Sustaining	80	105	(23.8%)	152	195	(22.1%)
Development	62	49	26.5%	109	90	21.1%
Other	9	24	(62.5%)	28	36	(22.2%)
	151	178	(15.2%)	289	321	(10.0%)
Total capital investments	403	416	(3.1%)	750	794	(5.5%)

Transmission Capital Investments

Transmission capital investments increased by $14 million or 5.9% during the second quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- work on the Leamington Transmission Station project to address the electricity needs in Windsor and Essex County;
- higher volume of overhead lines and component refurbishments and replacements; and
- higher volume of demand work associated with equipment failures; partially offset by
- timing of work related to the Clarington Transmission Station project; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects.

Transmission capital investments decreased by $12 million or 2.5% during the six months ended June 30, 2017. Principal impacts on the levels of capital investments included:

- substantial completion of the construction work on Clarington Transmission Station;
- lower volume of sustainment project work;
- substantial completion of the Guelph Area Transmission Refurbishment project; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- continued work on major development projects, such as the Holland, Hawthorne, and Leamington transmission stations;
- higher volume of demand work associated with equipment failures and higher volumes of spare transformer equipment purchases to ensure readiness for unplanned replacements; and
- higher volume of overhead lines and component refurbishments and replacements.

Distribution Capital Investments

Distribution capital investments decreased by $27 million or 15.2% during the second quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of wood pole replacements;
- lower volume of distribution lines sustainment work;
- lower volume of work within station refurbishment programs; and
- lower volume of fleet and work equipment purchases; partially offset by
- higher volume of storm restoration work as a result of multiple storms in the second quarter of 2017; and
- higher volume of work in new connections and upgrades due to increased demand.

Distribution capital investments decreased by $32 million or 10.0% during the six months ended June 30, 2017 primarily due to factors noted above, and were also impacted by lower storm costs in the first quarter of 2017 as last year's first quarter costs were elevated by an ice storm in March 2016, and timing of work on the Advanced Distribution System project.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at June 30, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$35 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$210 million
East-West Tie Station Expansion	Northern Ontario	Station expansion	2021	$157 million	$5 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	—
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$95 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$75 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2021	$93 million	$43 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$33 million

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Cash provided by operating activities	266	283	725	652
Cash provided by (used in) financing activities	133	(109)	(27)	28
Cash used in investing activities	(392)	(413)	(739)	(768)
Increase (decrease) in cash and cash equivalents	7	(239)	(41)	(88)

Cash provided by operating activities

Cash from Operating Activities decreased by $17 million during the second quarter of 2017 primarily due to lower net income and changes in accrual balances, partly offset by changes in regulatory variance accounts that impact revenue.

Cash from Operating Activities increased by $73 million year-to-date primarily due to factors noted above, as well as decreased energy-related receivables as a result of lower revenues in 2017 primarily reflecting lower commodity and global adjustment prices initiated by the Province's Fair Hydro Plan and lower consumption reflecting mild weather.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the three or six months ended June 30, 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $1,006 million and $1,578 million from issuance of short-term notes in the three and six months ended June 30, 2017, respectively, compared to $764 million and $1,495 million received in the three and six months ended June 30, 2016, respectively,

Uses of cash

- In the three and six months ended June 30, 2017, the company made returns of stated capital of $129 million and $276 million, respectively, compared to returns of stated capital of $125 million and $351 million made in the three and six months ended June 30, 2016, respectively.

- The Company repaid $742 million and $1,332 million of short-term notes in the three and six months ended June 30, 2017, respectively, compared to $771 million and $2,038 million repaid in the three and six months ended June 30, 2016, respectively.
- The Company repaid $1 million of long-term debt in the three and six months ended June 30, 2017, compared to long-term debt of $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $19 million and $43 million lower in the second quarter and year-to-date 2017, respectively, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's commercial paper program, and bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At June 30, 2017, Hydro One had $715 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, Hydro One has revolving bank credit facilities totalling $2.3 billion maturing in 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At June 30, 2017, the Company's long-term debt in the principal amount of $10,670 million included $10,523 million of long-term debt issued under its Medium Term Note (MTN) Program and long-term debt in the principal amount of $147 million held by Hydro One Sault Ste. Marie. At June 30, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at June 30, 2017, had an average term to maturity of approximately 15.4 years and a weighted average coupon rate of 4.3%.

At June 30, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

On July 19, 2017, Standard & Poor's Rating Services and Moody's Investors Service revised their outlooks on the Company to negative from stable, while affirming the existing debt ratings.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

June 30, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,670	602	2,134	1,106	6,828
Long-term debt – interest payments	7,916	437	815	739	5,925
Short-term notes payable	715	715	—	—	—
Pension contributions[1]	192	77	115	—	—
Environmental and asset retirement obligations	230	27	52	69	82
Outsourcing agreements	286	134	140	6	6
Operating lease commitments	35	10	14	9	2
Long-term software/meter agreement	64	16	34	11	3
Total contractual obligations	20,108	2,018	3,304	1,940	12,846
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,300	—	—	2,300	—
Letters of credit[3]	162	162	—	—	—
Guarantees[4]	325	325	—	—	—
Total other commercial commitments	2,787	487	—	2,300	—

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017, 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[2] In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

[3] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $5 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision pending
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Cost-of-service	OEB decision pending
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,554 million	Filed in May 2016	To be filed in 2017 Q3
	2018	8.78% (F)	$11,226 million	Filed in May 2016	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Filed in December 2016	Filed in December 2016
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017[1]	To be filed in 2018 Q2
	2019	8.78% (F)	$8,050 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	8.78% (F)	$8,478 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	8.78% (F)	$9,037 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	8.78% (F)	$9,437 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7, 2017, Hydro One Networks filed an update to the application reflecting recent financial results and other adjustments.

Hydro One Networks

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application). The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in the first half of 2018, and that new rates will be effective January 1, 2018.

B2M LP

On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. Hydro One intends to file a Notice of Motion no later than August 16, 2017, requesting the OEB to review and to cancel or vary the Procedural Order.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan and First Nations Rate Assistance Program came into effect on July 1, 2017. The Company's recommendation to provide a credit on the delivery charge for on-reserve First Nations customers was implemented. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Effective July 1, 2017, a reduction of 25% was introduced on electricity bills for typical Ontario residents. This reduction includes the 8% rebate from the *Ontario Rebate for Electricity Consumers Act, 2016*, and a reduction of the RRRP charge from $0.0021/kWh to $0.0003/kWh for Ontario ratepayers. The OESP charge was removed from customer bills as of May 1, 2017.

Hydro One customers will see the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to ensure the required applications are submitted to receive the benefits associated with the First Nations Rate Assistance Program, and to receive the credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits (OPEB) Costs

On May 18, 2017, the OEB issued a Regulatory Treatment of Pension and OPEB Costs Report (Report) that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential. Comments on implementation matters were submitted to the OEB in June 2017.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $900 million as at December 31, 2016) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Pension Plan

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and projected levels of pensionable earnings, the estimated total employer annual pension contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million and $71 million, respectively. The estimated 2017 annual employer contributions have decreased by approximately $17 million from $105 million based on improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. The updated actuarial valuation resulted in a $4 million decrease in OM&A costs, which will be refunded to ratepayers through the pension cost variance deferral account in future rate applications. Subsequent to approval of the 2017-2018 transmission cost-of-service application, the decrease in OM&A costs would correspond with a decrease in revenues.

Collective Agreement

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Net cash from operating activities	266	283	725	652
Changes in non-cash balances related to operations	133	56	64	73
Distributions to noncontrolling interest	(3)	(1)	(3)	(4)
FFO	396	338	786	721

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Revenues	1,361	1,533	3,007	3,205
Less: Purchased power	649	803	1,538	1,699
Revenues, net of purchased power	712	730	1,469	1,506

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Distribution revenues	998	1,152	2,277	2,438
Less: Purchased power	649	803	1,538	1,699
Distribution revenues, net of purchased power	349	349	739	739

FFO and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 49.9% ownership at June 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), OEB, and Hydro One Telecom Inc. (Hydro One Telecom) are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three and six months ended June 30, 2017 and 2016:

(millions of dollars)		Three months ended June 30		Six months ended June 30	
Related Party	Transaction	2017	2016	2017	2016
IESO	Power purchased	242	335	893	1,045
	Revenues for transmission services	365	375	734	751
	Amounts related to electricity rebates	63	—	140	—
	Distribution revenues related to rural rate protection	63	32	124	63
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	16	16
	Funding received related to Conservation and Demand Management programs	10	17	26	24
OPG	Power purchased	1	1	5	3
	Revenues related to provision of construction and equipment maintenance services	1	—	1	1
	Costs expensed related to the purchase of services	1	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	1	1	1
OEB	OEB fees	2	3	4	7
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	1	—	2
Hydro One Limited	Return of stated capital	129	125	276	351
	Dividends paid	4	—	6	2
	Stock-based compensation costs	6	6	12	11
Hydro One Telecom	Service received - costs expensed	6	7	12	13
	Service received - costs capitalized	—	3	—	6
	Revenues for services provided	—	—	1	—

RISK FACTORS

Risk associated with change in Hydro One Limited capital structure

A change in the capital structure of Hydro One Limited could cause credit rating agencies which rate the outstanding debt obligations of Hydro One to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the Company's 2016 annual MD&A.

Together, disclosure controls and procedures and internal control over financial reporting make up the systems that provide internal control over reporting and disclosure. These systems include policies and procedures designed to enable the reliability and timeliness of information disclosed by the Company. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior finance executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until a new Chief Financial Officer is appointed. There have been no other significant changes in the design of the Company's internal control over financial reporting during the six months ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10	May 2014 – May 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed by the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting rates and expected timing of decisions; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; collective agreements; future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEB costs; credit ratings; non-GAAP measures; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; and the Company's acquisitions, including Orillia Power. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;

- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)
For the three and six months ended June 30, 2017 and 2016

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars, except per share amounts)	2017	2016	2017	2016
Revenues				
Distribution (includes related party revenues of $71 (2016 – $41) and $140 (2016 – $81) for the three and six months ended June 30, respectively) *(Note 19)*	998	1,152	2,277	2,438
Transmission (includes related party revenues of $366 (2016 – $375) and $736 (2016 – $752) for the three and six months ended June 30, respectively) *(Note 19)*	363	381	730	767
	1,361	1,533	3,007	3,205
Costs				
Purchased power (includes related party costs of $243 (2016 – $337) and $899 (2016 – $1,049) for the three and six months ended June 30, respectively) *(Note 19)*	649	803	1,538	1,699
Operation, maintenance and administration *(Note 19)*	268	254	532	502
Depreciation and amortization *(Note 4)*	197	191	390	379
	1,114	1,248	2,460	2,580
Income before financing charges and income taxes	247	285	547	625
Financing charges	103	97	206	193
Income before income taxes	144	188	341	432
Income taxes *(Note 5)*	22	32	48	64
Net income	**122**	**156**	**293**	**368**
Other comprehensive income	—	—	1	—
Comprehensive income	**122**	**156**	**294**	**368**
Net income attributable to:				
Noncontrolling interest	2	1	3	2
Common shareholder	120	155	290	366
	122	**156**	**293**	**368**
Comprehensive income attributable to:				
Noncontrolling interest	2	1	3	2
Common shareholder	120	155	291	366
	122	**156**	**294**	**368**
Earnings per common share *(Note 17)*				
Basic	$844	$1,086	$2,039	$2,571
Diluted	$844	$1,086	$2,039	$2,571
Dividends per common share declared *(Note 16)*	$28	—	$42	$14

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At June 30, 2017 and December 31, 2016

(millions of Canadian dollars)	June 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	7	48
Accounts receivable *(Note 6)*	636	833
Due from related parties	366	224
Other current assets *(Note 7)*	97	97
	1,106	1,202
Property, plant and equipment *(Note 8)*	19,475	19,068
Other long-term assets:		
Regulatory assets	3,103	3,145
Deferred income tax assets	1,120	1,213
Intangible assets (net of accumulated amortization – $359; 2016 – $330)	349	349
Goodwill	327	327
Other assets	6	6
	4,905	5,040
Total assets	**25,486**	**25,310**
Liabilities		
Current liabilities:		
Bank indebtedness	13	—
Short-term notes payable *(Note 11)*	715	469
Long-term debt payable within one year *(Notes 11, 12)*	602	602
Accounts payable and other current liabilities *(Note 9)*	893	933
Due to related parties	147	253
	2,370	2,257
Long-term liabilities:		
Long-term debt (includes $546 measured at fair value; 2016 – $548) *(Notes 11, 12)*	10,072	10,078
Regulatory liabilities	223	209
Deferred income tax liabilities	63	60
Other long-term liabilities *(Note 10)*	2,808	2,765
	13,166	13,112
Total liabilities	**15,536**	**15,369**
Contingencies and Commitments (Notes 21, 22)		
Subsequent Events (Note 24)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 15)*	5,115	5,391
Retained earnings	4,771	4,487
Accumulated other comprehensive loss	(8)	(9)
Hydro One shareholders' equity	9,878	9,869
Noncontrolling interest	50	50
Total equity	**9,928**	**9,919**
	25,486	**25,310**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the six months ended June 30, 2017 and 2016

Six months ended June 30, 2017 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,391	4,487	(9)	9,869	50	9,919
Net income	—	290	—	290	2	292
Other comprehensive income	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	(2)	(2)
Dividends on common shares	—	(6)	—	(6)	—	(6)
Return on stated capital	(276)	—	—	(276)	—	(276)
June 30, 2017	**5,115**	**4,771**	**(8)**	**9,878**	**50**	**9,928**

Six months ended June 30, 2016 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	—	366	—	366	1	367
Distributions to noncontrolling interest	—	—	—	—	(3)	(3)
Dividends on common shares	—	(2)	—	(2)	—	(2)
Return on stated capital	(351)	—	—	(351)	—	(351)
June 30, 2016	**5,649**	**4,123**	**(9)**	**9,763**	**50**	**9,813**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and six months ended June 30, 2017 and 2016

	Three months ended June 30		Six months ended June 30	
(millions of Canadian dollars)	2017	2016	2017	2016
Operating activities				
Net income	122	156	293	368
Environmental expenditures	(8)	(7)	(12)	(10)
Adjustments for non-cash items:				
Depreciation and amortization (excluding asset removal costs)	174	168	346	332
Regulatory assets and liabilities	93	(12)	124	(22)
Deferred income taxes	17	36	37	57
Other	1	(2)	1	—
Changes in non-cash balances related to operations *(Note 20)*	(133)	(56)	(64)	(73)
Net cash from operating activities	266	283	725	652
Financing activities				
Long-term debt issued	—	—	—	1,350
Long-term debt repaid	(1)	—	(1)	(450)
Short-term notes issued	1,006	764	1,578	1,495
Short-term notes repaid	(742)	(771)	(1,332)	(2,038)
Return of stated capital	(129)	(125)	(276)	(351)
Dividends paid	(4)	—	(6)	(2)
Distributions paid to noncontrolling interest	(3)	(1)	(3)	(4)
Change in bank indebtedness	6	24	13	34
Other	—	—	—	(6)
Net cash from (used in) financing activities	133	(109)	(27)	28
Investing activities				
Capital expenditures *(Note 20)*				
Property, plant and equipment	(375)	(398)	(707)	(755)
Intangible assets	(19)	(15)	(33)	(28)
Capital contributions received	2	—	9	15
Other	—	—	(8)	—
Net cash used in investing activities	(392)	(413)	(739)	(768)
Net change in cash and cash equivalents	7	(239)	(41)	(88)
Cash and cash equivalents, beginning of period	—	240	48	89
Cash and cash equivalents, end of period	**7**	**1**	**7**	**1**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10	May 2014 – May 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed by the third quarter of 2017. The Company is on track for implementation of this standard by the effective date.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. DEPRECIATION AND AMORTIZATION

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Depreciation of property, plant and equipment	152	147	305	295
Asset removal costs	23	23	44	47
Amortization of intangible assets	14	14	29	27
Amortization of regulatory assets	8	7	12	10
	197	191	390	379

5. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	Six months ended June 30	
(millions of dollars)	2017	2016
Income taxes at statutory rate	90	115
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(21)	(23)
Pension contributions in excess of pension expense	(5)	(8)
Overheads capitalized for accounting but deducted for tax purposes	(7)	(7)
Interest capitalized for accounting but deducted for tax purposes	(6)	(9)
Environmental expenditures	(4)	(4)
Other	(1)	—
Net temporary differences	(44)	(51)
Net permanent differences	2	—
Total income taxes	48	64
Effective income tax rate	14.1%	14.8%

6. ACCOUNTS RECEIVABLE

(millions of dollars)	June 30, 2017	December 31, 2016
Accounts receivable – billed	359	427
Accounts receivable – unbilled	311	441
Accounts receivable, gross	670	868
Allowance for doubtful accounts	(34)	(35)
Accounts receivable, net	636	833

The following table shows the movements in the allowance for doubtful accounts for the six months ended June 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Six months ended June 30, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	12	37
Additions to allowance for doubtful accounts	(11)	(11)
Allowance for doubtful accounts – ending	(34)	(35)

7. OTHER CURRENT ASSETS

(millions of dollars)	June 30, 2017	December 31, 2016
Regulatory assets	31	37
Materials and supplies	19	19
Prepaid expenses and other assets	47	41
	97	97

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	June 30, 2017	December 31, 2016
Property, plant and equipment	28,008	27,523
Less: accumulated depreciation	(10,130)	(9,832)
	17,878	17,691
Construction in progress	1,434	1,223
Future use land, components and spares	163	154
	19,475	19,068

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	June 30, 2017	December 31, 2016
Accounts payable	174	177
Accrued liabilities	614	651
Accrued interest	103	105
Regulatory liabilities	2	—
	893	933

10. OTHER LONG-TERM LIABILITIES

(millions of dollars)	June 30, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,667	1,628
Pension benefit liability	897	900
Environmental liabilities *(Note 14)*	179	177
Due to related parties	28	26
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	28	25
	2,808	2,765

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One's committed revolving credit facilities totalling $2.3 billion. In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

Long-Term Debt

At June 30, 2017, long-term debt of $10,523 million was outstanding under the Company's Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At June 30, 2017, $1.2 billion remained available for issuance until January 2018. In addition, at June 30, 2017, the Company had long-term debt of $180 million related to Hydro One Sault Ste. Marie.

The following table presents long-term debt outstanding at June 30, 2017 and December 31, 2016:

(millions of dollars)	June 30, 2017	December 31, 2016
Notes and debentures	10,703	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[1]	(4)	(2)
Less: Deferred debt issuance costs	(39)	(40)
Total long-term debt	10,674	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,072	10,078

[1] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $4 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

During the six months ended June 30, 2017, Hydro One did not issue (2016 – issued $1,350 million), and repaid $1 million (2016 – $450 million) of long-term debt.

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.4
3 years	1,153	2.3
4 years	503	1.9
5 years	603	3.2
	3,842	2.9
6 – 10 years	633	3.5
Over 10 years	6,195	5.2
	10,670	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
Remainder of 2017	227
2018	425
2019	402
2020	384
2021	370
	1,808
2022-2026	1,703
2027+	4,405
	7,916

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At June 30, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at June 30, 2017 and December 31, 2016 are as follows:

	June 30, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt, including current portion				
$50 million of MTN Series 33 notes	50	50	50	50
$500 million MTN Series 37 notes	496	496	498	498
Other notes and debentures	10,128	11,779	10,132	11,462
	10,674	12,325	10,680	12,010

Fair Value Measurements of Derivative Instruments

At June 30, 2017, Hydro One had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One's fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At June 30, 2017, Hydro One had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At June 30, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at June 30, 2017 and December 31, 2016 is as follows:

June 30, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	7	7	7	—	—
	7	7	7	—	—
Liabilities:					
Bank indebtedness	13	13	13	—	—
Short-term notes payable	715	715	715	—	—
Long-term debt, including current portion	10,674	12,325	—	12,325	—
Derivative instruments					
Fair value hedges – interest-rate swaps	4	4	4	—	—
	11,406	13,057	732	12,325	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	48	48	48	—	—
	48	48	48	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the six months ended June 30, 2017 or year ended December 31, 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three and six months ended June 30, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and six months ended June 30, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At June 30, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At June 30, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At June 30, 2017, the Company's provision for bad debts was $34 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At June 30, 2017, approximately 7% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At June 30, 2017 and December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At June 30, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

13. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million, and $71 million, respectively, based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Employer contributions made during the six months ended June 30, 2017 were $47 million (2016 – $75 million).

The following tables provide the components of the net periodic benefit costs for the three and six months ended June 30, 2017 and 2016:

Three months ended June 30 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Current service cost	37	36	12	10
Interest cost	76	77	16	16
Expected return on plan assets, net of expenses[1]	(111)	(108)	—	—
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	29	30	28
Charged to results of operations[2]	7	3	12	11

Six months ended June 30 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Current service cost	73	72	24	21
Interest cost	152	154	33	33
Expected return on plan assets, net of expenses[1]	(221)	(217)	—	—
Actuarial loss amortization	40	48	4	4
Net periodic benefit costs	44	57	61	58
Charged to results of operations[2]	20	25	26	24

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three and six months ended June 30, 2017, pension costs of $15 million (2016 – $7 million) and $45 million (2016 – $57 million), respectively, were attributed to labour, of which $7 million (2016 – $3 million) and $20 million (2016 – $25 million), respectively, were charged to operations, and $8 million (2016 – $4 million) and $25 million (2016 – $32 million) respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

14. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the six months ended June 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Six months ended June 30, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	4	8
Expenditures	(12)	(20)
Revaluation adjustment	11	9
Environmental liabilities – ending	207	204
Less: current portion	(28)	(27)
	179	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	June 30, 2017	December 31, 2016
Undiscounted environmental liabilities	221	224
Less: discounting accumulated liabilities to present value	14	20
Discounted environmental liabilities	207	204

Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At June 30, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2017 [1]	15
2018	25
2019	25
2020	30
2021	37
Thereafter	89
	221

[1] The amounts disclosed represent amounts for the period from July 1, 2017 to December 31, 2017.

15. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At June 30, 2017 and December 31, 2016, the Company had 142,239 common shares issued and outstanding.

During the three and six months ended June 30, 2017, the Company returned stated capital of $129 million (2016 – $125 million) and $276 million (2016 – $351 million), respectively.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At June 30, 2017 and December 31, 2016, Hydro One had no issued and outstanding preferred shares.

16. DIVIDENDS

During the three and six months ended June 30, 2017, common share dividends in the amount of $4 million (2016 – $nil) and $6 million (2016 – $2 million), respectively, were declared and paid.

17. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding during the three and six months ended June 30, 2017 was 142,239 (2016 - 142,239). There were no dilutive securities during the three and six months ended June 30, 2017 and 2016.

18. STOCK-BASED COMPENSATION

Share Grant Plans

A summary of share grant activity under the Share Grant Plans during the three and six months ended June 30, 2017 and 2016 is presented below:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Share grants outstanding - beginning	5,239,678	5,319,370	5,239,678	5,319,370
Vested[1]	(369,266)	—	(369,266)	—
Share grants outstanding - ending	4,870,412	5,319,370	4,870,412	5,319,370

[1] On April 1, 2017, Hydro One Limited issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

Directors' Deferred Share Units (DSU) Plan

During the three and six months ended June 30, 2017 and 2016, the Company granted awards under its Directors' DSU Plan, as follows:

	Three months ended June 30		Six months ended June 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	119,763	40,465	99,083	20,525
DSUs granted	21,790	18,740	42,470	38,680
DSUs outstanding – ending	141,553	59,205	141,553	59,205

At June 30, 2017, a liability of $3 million (December 31, 2016 – $2 million) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $23.23 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Company's Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the three and six months ended June 30, 2017 and 2016, the Company granted awards under its Management' DSU Plan, as follows:

	Three months ended June 30		Six months ended June 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	62,999	—	—	—
DSUs granted	594	—	63,593	—
DSUs outstanding – ending	63,593	—	63,593	—

At June 30, 2017, a liability of $2 million (December 31, 2016 – $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $23.23 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three and six months ended June 30, 2017 and 2016, Hydro One Limited granted awards under its Long-term Incentive Plan (LTIP), consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled in Hydro One Limited shares, as follows:

	PSUs		RSUs	
Three months ended June 30 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	478,755	122,410	451,925	147,410
Units granted	—	—	—	—
Units vested	—	—	(13,470)	—
Units forfeited	(40,520)	—	(34,100)	—
Units outstanding - ending	438,235	122,410	404,355	147,410

	PSUs		RSUs	
Six months ended June 30 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	228,890	—	252,440	—
Units granted	264,300	122,410	215,370	147,410
Units vested	—	—	(13,470)	—
Units forfeited	(54,955)	—	(49,985)	—
Units outstanding - ending	438,235	122,410	404,355	147,410

The grant date total fair value of the awards granted during the three and six months ended June 30, 2017 was $nil and $12 million (2016 – $nil and $7 million), respectively. The compensation expense recognized by the Company relating to LTIP awards during the three and six months ended June 30, 2017 was $2 million and $3 million (2016 – not significant), respectively.

19. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 49.9% ownership at June 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), OEB, and Hydro One Telecom Inc. (Hydro One Telecom) are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

(millions of dollars)		Three months ended June 30		Six months ended June 30	
Related Party	**Transaction**	**2017**	**2016**	**2017**	**2016**
IESO	Power purchased	242	335	893	1,045
	Revenues for transmission services	365	375	734	751
	Amounts related to electricity rebates	63	—	140	—
	Distribution revenues related to rural rate protection	63	32	124	63
	Distribution revenues related to the supply of electricity to remote northern	8	8	16	16
	Funding received related to Conservation and Demand Management programs	10	17	26	24
OPG	Power purchased	1	1	5	3
	Revenues related to provision of construction and equipment maintenance	1	—	1	1
	Costs expensed related to the purchase of services	1	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	1	1	1
OEB	OEB fees	2	3	4	7
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	1	—	2
Hydro One Limited	Return of stated capital	129	125	276	351
	Dividends paid	4	—	6	2
	Stock-based compensation costs	6	6	12	11
Hydro One Telecom	Service received - costs expensed	6	7	12	13
	Service received - costs capitalized	—	3	—	6
	Revenues for services provided	—	—	1	—

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Accounts receivable	99	92	190	15
Due from related parties	(85)	(53)	(142)	(32)
Materials and supplies	—	—	—	1
Prepaid expenses and other assets	(5)	(23)	(6)	(30)
Accounts payable	4	15	3	21
Accrued liabilities	(58)	32	(39)	25
Due to related parties	(77)	(120)	(108)	(117)
Accrued interest	(27)	(19)	(2)	5
Long-term accounts payable and other liabilities	(1)	4	1	4
Post-retirement and post-employment benefit liability	17	16	39	35
	(133)	(56)	(64)	(73)

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Capital investments in property, plant and equipment	(388)	(400)	(722)	(766)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	13	2	15	11
Capital expenditures – property, plant and equipment	(375)	(398)	(707)	(755)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Capital investments in intangible assets	(15)	(16)	(28)	(28)
Net change in accruals included in capital investments in intangible assets	(4)	1	(5)	—
Capital expenditures – intangible assets	(19)	(15)	(33)	(28)

Supplementary Information

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2017	2016	2017	2016
Net interest paid	131	122	219	202
Income taxes paid	3	5	7	13

21. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

22. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

June 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	134	93	47	2	4	6
Long-term software/meter agreement	16	17	17	9	2	3
Operating lease commitments	10	8	6	7	2	2

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

June 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	—	2,300	—
Letters of credit[1]	162	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, a $5 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended June 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	363	998	—	1,361
Purchased power	—	649	—	649
Operation, maintenance and administration	103	154	11	268
Depreciation and amortization	103	94	—	197
Income (loss) before financing charges and income taxes	157	101	(11)	247
Capital investments	252	151	—	403

Three months ended June 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	381	1,152	—	1,533
Purchased power	—	803	—	803
Operation, maintenance and administration	97	146	11	254
Depreciation and amortization	94	97	—	191
Income (loss) before financing charges and income taxes	190	106	(11)	285
Capital investments	238	178	—	416

Six months ended June 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	730	2,277	—	3,007
Purchased power	—	1,538	—	1,538
Operation, maintenance and administration	209	301	22	532
Depreciation and amortization	204	186	—	390
Income (loss) before financing charges and income taxes	317	252	(22)	547
Capital investments	461	289	—	750

Six months ended June 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	767	2,438	—	3,205
Purchased power	—	1,699	—	1,699
Operation, maintenance and administration	198	289	15	502
Depreciation and amortization	189	190	—	379
Income (loss) before financing charges and income taxes	380	260	(15)	625
Capital investments	473	321	—	794

Total Assets by Segment:

(millions of dollars)	June 30, 2017	December 31, 2016
Transmission	13,339	13,083
Distribution	9,308	9,393
Other	2,839	2,834
Total assets	25,486	25,310

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. SUBSEQUENT EVENTS

Dividends

On August 8, 2017, common share dividends in the amount of $5 million were declared, and a return of stated capital in the amount of $129 million was approved.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the condensed interim unaudited consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the three and nine months ended September 30, 2017, as well as the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2016. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which vary from those of the US. This MD&A provides information for the three and nine months ended September 30, 2017, based on information available to management as of November 9, 2017.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

	Three months ended September 30			Nine months ended September 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Revenues	1,511	1,693	(10.8%)	4,518	4,898	(7.8%)
Purchased power	675	870	(22.4%)	2,213	2,569	(13.9%)
Revenues, net of purchased power[1]	836	823	1.6%	2,305	2,329	(1.0%)
Operation, maintenance and administration costs	252	258	(2.3%)	784	760	3.2%
Depreciation and amortization	207	189	9.5%	597	568	5.1%
Financing charges	104	98	6.1%	310	291	6.5%
Income tax expense	31	43	(27.9%)	79	107	(26.2%)
Net income attributable to common shareholder of Hydro One	**241**	**233**	**3.4%**	**531**	**599**	**(11.4%)**
Basic earnings per common share (EPS)	$1,694	$1,638	3.4%	$3,733	$4,211	(11.4%)
Diluted EPS	$1,694	$1,638	3.4%	$3,733	$4,211	(11.4%)
Net cash from operating activities	432	535	(19.3%)	1,157	1,187	(2.5%)
Funds from operations (FFO)[1]	412	428	(3.7%)	1,198	1,149	4.3%
Capital investments	378	422	(10.4%)	1,128	1,216	(7.2%)
Assets placed in-service	292	382	(23.6%)	849	900	(5.7%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,857	22,991	(9.3%)	19,801	21,115	(6.2%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,226	6,621	(6.0%)	19,046	19,784	(3.7%)

	2017	2016
Debt to capitalization ratio[2]	53.5%	52.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been presented at September 30, 2017 and December 31, 2016, and has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholder's equity, but excluding any amounts related to non-controlling interest.

OVERVIEW

For the nine months ended September 30, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	52%	48%	—%

At September 30, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	52%	36%	12%

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholder for the quarter ended September 30, 2017 of $241 million is an increase of $8 million or 3.4% from the prior year. Significant influences on net income included:

- milder weather in 2017 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand, and a decrease in distribution revenues due to lower energy consumption. Transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher transmission revenues driven by Ontario Energy Board's (OEB) decision on the 2017-2018 transmission rates filing, including higher disposition of certain OEB-approved variance accounts, higher export service credits, and higher rate revenues;
- lower operation, maintenance and administration (OM&A) costs primarily resulting from reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during the third quarter of 2017 compared to the third quarter of 2016, including long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016.

Net income attributable to common shareholder for the nine months ended September 30, 2017 of $531 million is a decrease of $68 million or 11.4% from the prior year. In addition to factors noted above, net income for the nine months ended September 30, 2017 was also impacted by the following:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system (excluding this adjustment in 2016, the bad debt expense was relatively flat year-over-year); and
- higher consulting costs primarily related to strategy development and higher corporate management costs in the first quarter of 2017.

Revenues

	Three months ended September 30			Nine months ended September 30		
(millions of dollars, except as otherwise noted)	2017	2016	Change	2017	2016	Change
Transmission	471	444	6.1%	1,201	1,211	(0.8%)
Distribution	1,040	1,249	(16.7%)	3,317	3,687	(10.0%)
Total revenues	1,511	1,693	(10.8%)	4,518	4,898	(7.8%)
Transmission	471	444	6.1%	1,201	1,211	(0.8%)
Distribution, net of purchased power	365	379	(3.7%)	1,104	1,118	(1.3%)
Total revenues, net of purchased power	836	823	1.6%	2,305	2,329	(1.0%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,857	22,991	(9.3%)	19,801	21,115	(6.2%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	6,226	6,621	(6.0%)	19,046	19,784	(3.7%)

<u>Transmission Revenues</u>

Transmission revenues increased by 6.1% for the third quarter primarily due to the following:

- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, including higher disposition of certain OEB-approved variance accounts, higher export service credits, and higher rate revenues; and
- additional revenues resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016; partially offset by
- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in 2017; and
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%.

The decrease in transmission revenues for the nine months ended September 30, 2017 of 0.8% was mainly the result of similar factors as noted above, with lower peak demand and transmission rates more than offsetting increased revenues driven by the OEB's decision on the 2017-2018 transmission rates filing and the acquisition of Hydro One Sault Ste. Marie.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, decreased by 3.7% and 1.3% for the third quarter and nine months ended September 30, 2017, respectively. During the third quarter and year-to-date, lower energy consumption resulting from milder weather in 2017 was partially offset by increased OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	98	97	1.0%	307	295	4.1%
Distribution	151	162	(6.8%)	452	451	0.2%
Other	3	(1)	400.0%	25	14	78.6%
	252	258	(2.3%)	784	760	3.2%

Transmission OM&A Costs

Transmission OM&A costs for the quarter ended September 30, 2017 were comparable to prior year, and were impacted by:

- lower support services costs;
- lower volume of vegetation management work; and
- higher volume of stations and overhead maintenance work due to increased demand.

The increase of 4.1% for the nine months ended September 30, 2017, was primarily due to:

- additional OM&A costs resulting from the acquisition of Hydro One Sault Ste. Marie in the fourth quarter of 2016; and
- higher volume of environmental management program work; partially offset by
- lower volume of vegetation management work.

Distribution OM&A Costs

The decrease of 6.8% in distribution OM&A costs for the quarter ended September 30, 2017 was primarily due to:

- lower volume of vegetation management work;
- lower consulting costs; and
- lower support services costs; partially offset by
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the quarter.

Distribution OM&A costs for the nine months ended September 30, 2017 were comparable to prior year, and were primarily impacted by:

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system (excluding this adjustment in 2016, bad debt expense would have been relatively flat year-over-year);
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the quarter; and
- lower volume of vegetation management work.

Other OM&A Costs

The increase in other OM&A costs for the nine months ended September 30, 2017 was mainly due to higher consulting costs primarily related to strategy development and higher corporate management costs in the first quarter of 2017.

Financing Charges

The increase of $6 million or 6.1% in financing charges for the third quarter of 2017 was primarily due to an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during the third quarter of 2017, including the long-term debt assumed as part of the Hydro One Sault Ste. Marie acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt;.

The increase of $19 million or 6.5% in financing charges for the nine months ended September 30, 2017 was the result of similar factors as noted above, and was partially offset by a decrease in interest expense on short-term notes payable mainly due to a lower weighted average balance in 2017, as well as a decrease in the weighted average interest rate for short-term notes.

Income Tax Expense

The effective tax rate for the three and nine months ended September 30, 2017 was 11.4% and 12.9%, respectively, compared to 15.5% and 15.1% for the three and nine months ended September 30, 2016, respectively. The decreases in income tax expense of $12 million and $28 million for the three and nine months ended September 30, 2017, respectively, were primarily due to lower income before taxes in 2017.

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS and ratio)*	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016	Dec 31, 2015
Revenues	1,511	1,361	1,646	1,604	1,693	1,533	1,672	1,513
Purchased power	675	649	889	858	870	803	896	786
Revenues, net of purchased power	836	712	757	746	823	730	776	727
Net income to common shareholder	241	120	170	131	233	155	211	132
Basic and diluted EPS	$1,694	$844	$1,195	$921	$1,638	$1,086	$1,485	$1,036
Earnings coverage ratio[1]	2.5	2.6	2.7	2.8	2.8	2.7	2.6	2.7

[1] Earnings coverage ratio has been presented for the twelve months ended as of each date indicated above and has been calculated as net income before financing charges and income taxes attributable to shareholders of Hydro One, divided by the sum of financing charges, capitalized interest, and preferred dividends. The earnings coverage ratio for the twelve months ended September 30, 2015 was 2.9.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-service

The following table presents Hydro One's assets placed in-service during the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission	120	224	(46.4%)	367	449	(18.3%)
Distribution	172	158	8.9%	482	451	6.9%
Total assets placed in-service	292	382	(23.6%)	849	900	(5.7%)

Transmission Assets Placed In-service

Transmission assets placed in-service decreased by $104 million or 46.4% during the third quarter of 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in the third quarter of 2016; and
- a larger number of cumulative sustainment investments placed in-service in the third quarter of 2016, including the breaker replacement project at Richview transmission station, the asset replacement project at Gerrard transmission station, and the transformer replacement at Brant transmission station.

Transmission assets placed in-service decreased by $82 million or 18.3% during the nine months ended September 30, 2017 primarily due to factors noted above, partially offset by the following:

- a larger number of cumulative sustainment investments that were placed in-service in the first half of 2017, including the asset replacement project at Aylmer transmission station and the station reconfiguration project at Goderich transmission station; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-service

Distribution assets placed in-service increased by $14 million or 8.9% during the third quarter of 2017 primarily due to the following:
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017;
- higher volume of subdivision connections due to increased demand; and
- higher volume of service equipment purchases; partially offset by
- timing of distribution station refurbishments and spare transformer purchases.

Distribution assets placed in-service increased by $31 million or 6.9% during the nine months ended September 30, 2017 primarily due to the following:
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017;
- higher volume of subdivision connections due to increased demand; and
- higher volume of service equipment purchases; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during the first half of 2016; and
- lower volume of fleet and work equipment purchases.

Capital Investments

The following table presents Hydro One's capital investments during the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30			Nine months ended September 30		
(millions of dollars)	2017	2016	Change	2017	2016	Change
Transmission						
Sustaining	189	180	5.0%	548	542	1.1%
Development	32	44	(27.3%)	108	123	(12.2%)
Other	19	17	11.8%	45	49	(8.2%)
	240	241	(0.4%)	701	714	(1.8%)
Distribution						
Sustaining	63	96	(34.4%)	215	291	(26.1%)
Development	53	62	(14.5%)	162	152	6.6%
Other	22	23	(4.3%)	50	59	(15.3%)
	138	181	(23.8%)	427	502	(14.9%)
Total capital investments	378	422	(10.4%)	1,128	1,216	(7.2%)

Transmission Capital Investments

Transmission capital investments decreased by $1 million or 0.4% during the third quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:
- timing of work related to the Clarington Transmission Station project; and
- lower volume of transmission station refurbishments and component replacements work; partially offset by
- higher volume of overhead lines and component refurbishments and replacements.

Transmission capital investments decreased by $13 million or 1.8% during the nine months ended September 30, 2017. Principal impacts on the levels of capital investments included:
- construction work on Clarington Transmission Station project is substantially complete;
- lower volume of transmission station refurbishments and component replacements work; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- timing and substantial completion of major development projects including the Holland, Hawthorne, and Leamington transmission stations; and
- higher volume of overhead lines and component refurbishments and replacements.

Distribution Capital Investments

Distribution capital investments decreased by $43 million or 23.8% during the third quarter of 2017. Principal impacts on the levels of capital investments for the quarter included:

- lower volume of work within station refurbishment programs;
- lower volume of distribution lines sustainment work;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of work on storm damage and emergency power restorations; and
- lower volume of wood pole replacements.

Distribution capital investments decreased by $75 million or 14.9% during the nine months ended September 30, 2017 primarily due to factors noted above, and were also impacted by

- lower volume of work within station refurbishment programs;
- lower volume of wood pole replacements;
- lower volume of distribution lines sustainment work;
- lower volume of fleet and work equipment purchases; and
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at September 30, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$73 million	$46 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$216 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$6 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	To be determined	To be determined	—
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2019	$109 million	$100 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$79 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$46 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$38 million

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2017 to 2021. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. These estimates differ from the prior year disclosures for 2017 and 2018 transmission capital investments, representing annual decreases of $126 million for 2017 and $122 million for 2018. These decreases reflect the OEB's focus on planning practices and the pacing of Sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2021 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by business segment:

(millions of dollars)	2017	2018	2019	2020	2021
Transmission	960	1,010	1,217	1,278	1,486
Distribution	648	647	771	735	749
Total capital investments	**1,608**	**1,657**	**1,988**	**2,013**	**2,235**

The following table summarizes Hydro One's annual projected capital investments for 2017 to 2021, by category:

(millions of dollars)	2017	2018	2019	2020	2021
Sustainment	1,089	1,103	1,219	1,327	1,546
Development	335	340	484	487	490
Other[1]	184	214	285	199	199
Total capital investments	**1,608**	**1,657**	**1,988**	**2,013**	**2,235**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Cash provided by operating activities	432	535	1,157	1,187
Cash provided by financing activities	31	4	4	32
Cash used in investing activities	(380)	(412)	(1,119)	(1,180)
Increase in cash and cash equivalents	83	127	42	39

Cash provided by operating activities

Cash from Operating Activities decreased by $103 million during the third quarter of 2017 primarily due to lower net income and changes in accrual balances, partially offset by decreased energy-related receivables as a result of lower revenues in 2017 primarily reflecting lower commodity and global adjustment prices initiated by the Province of Ontario's (Province) Fair Hydro Plan and lower consumption reflecting mild weather.

Cash from Operating Activities decreased by $30 million year-to-date primarily due to factors noted above, as well as changes in regulatory variance and deferral accounts that impact revenue.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in the three or nine months ended September 30, 2017, compared to proceeds from the issuance of $1,350 million in the first quarter of 2016.
- The Company received proceeds of $1,232 million and $2,810 million from the issuance of short-term notes in the three and nine months ended September 30, 2017, respectively, compared to $940 million and $2,435 million received in the three and nine months ended September 30, 2016, respectively,

Uses of cash

- In the three and nine months ended September 30, 2017, the company made returns of stated capital of $129 million and $405 million, respectively, compared to returns of stated capital of $129 million and $480 million made in the three and nine months ended September 30, 2016, respectively.
- The Company repaid $1,053 million and $2,385 million of short-term notes in the three and nine months ended September 30, 2017, respectively, compared to $770 million and $2,808 million repaid in the three and nine months ended September 30, 2016, respectively.
- The Company repaid $1 million of long-term debt in the three and nine months ended September 30, 2017, compared to long-term debt of $450 million repaid in the first quarter of 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $32 million and $75 million lower in the third quarter and year-to-date 2017, respectively, primarily due to lower volume and timing of capital investment work.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's commercial paper program, and bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At September 30, 2017, Hydro One had $894 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, Hydro One has revolving bank credit facilities totalling $2.3 billion maturing in 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At September 30, 2017, the Company's long-term debt in the principal amount of $10,670 million included $10,523 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $147 million held by Hydro One Sault Ste. Marie. At September 30, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2017 and 2064, and at September 30, 2017, had an average term to maturity of approximately 15.1 years and a weighted average coupon rate of 4.3%.

At September 30, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

On July 19, 2017, Standard & Poor's Rating Services and Moody's Investors Service revised their outlooks on the Company to negative from stable, while affirming the existing debt ratings.

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

September 30, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,670	602	2,134	1,106	6,828
Long-term debt – interest payments	7,831	442	811	725	5,853
Short-term notes payable	894	894	—	—	—
Pension contributions[1]	172	75	97	—	—
Environmental and asset retirement obligations	223	26	54	69	74
Outsourcing agreements	247	118	118	9	2
Operating lease commitments	33	10	16	5	2
Long-term software/meter agreement	61	17	34	7	3
Total contractual obligations	20,131	2,184	3,264	1,921	12,762
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,300	—	—	2,300	—
Letters of credit[3]	165	165	—	—	—
Guarantees[4]	325	325	—	—	—
Total other commercial commitments	2,790	490	—	2,300	—

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2017, 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[2] In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

[3] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, an $8 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Hydro One Sault Ste. Marie	2017	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Filed in October 2017
	2018	8.78% (F)	$11,148 million	Approved in September 2017	To be filed in 2017 Q4
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	8.78% (F)	$502 million	Approved in December 2015	To be filed in 2017 Q4
	2019	8.78% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
Hydro One Sault Ste. Marie	2017	9.19% (F)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	8.78% (F)	$7,672 million	Filed in March 2017[1]	To be filed in 2018 Q3
	2019	8.78% (F)	$8,050 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	8.78% (F)	$8,478 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	8.78% (F)	$9,037 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	8.78% (F)	$9,437 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7, 2017, Hydro One Networks filed an update to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks Inc.'s (Hydro One Networks) 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the OEB's decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax to the Ontario Electricity Financial Corporation (OEFC) Regime to the Federal Tax Regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. The OEB proposed a basis for sharing a portion of the tax savings resulting from the deferred tax asset with ratepayers by reducing the amount of cash taxes approved for recovery in Hydro One Networks' 2017-2018 transmission rates. On November 9, 2017, the OEB issued a Decision and Order that modified the portion of the tax savings that should be shared with ratepayers. This proposed methodology would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same methodology for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an impairment of Hydro One Networks' distribution deferred income tax regulatory asset of up to approximately $370 million.

In October 2017, the Company filed a Motion to Review and Vary the Decision (Motion) and filed an appeal with the Divisional Court of Ontario (Appeal). The Motion seeks allocation of the full amount of future tax savings from the Deferred Tax Asset of $2,595 million to shareholders; a recovery of $5 million in 2018 for allowance for funds used during construction relating to the Niagara Reinforcement Project; and the recovery of approximately $1 million related to costs for the Ombudsman's Office. With respect to the Deferred Tax Assets, in both the Motion and Appeal, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The outcome of the Motion to Review and Vary as well as the Appeal are uncertain. If the decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application). The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

B2M LP

On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017, and as such, Hydro One is not required to file a Draft Rate Order for 2017.

Hydro One Sault Ste. Marie

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Sault Ste. Marie's 2017 transmission rates application, denying the requested revenue requirement for 2017. Hydro One Sault Ste. Marie's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure, a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that it plans to file a Leave to Construct application to construct the East-West Tie Line Project.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) program, the introduction of the First Nations Rate Assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations Rate Assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan and First Nations Rate Assistance Program came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations Rate Assistance Program, and to receive the credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $900 million as at December 31, 2016) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Pension Plan

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and projected levels of pensionable earnings, the estimated total employer annual pension contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million and $71 million, respectively. The estimated 2017 annual employer contributions have decreased by approximately $17 million from $105 million based on improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals and the Power Workers' Union to facilitate the insourcing of these services effective March 1, 2018.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Net cash from operating activities	432	535	1,157	1,187
Changes in non-cash balances related to operations	(19)	(104)	45	(31)
Distributions to noncontrolling interest	(1)	(3)	(4)	(7)
FFO	412	428	1,198	1,149

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Revenues	1,511	1,693	4,518	4,898
Less: Purchased power	675	870	2,213	2,569
Revenues, net of purchased power	836	823	2,305	2,329

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Distribution revenues	1,040	1,249	3,317	3,687
Less: Purchased power	675	870	2,213	2,569
Distribution revenues, net of purchased power	365	379	1,104	1,118

FFO and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 49.9% ownership at September 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), OEFC, the OEB, and Hydro One Telecom Inc. (Hydro One Telecom) are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the three and nine months ended September 30, 2017 and 2016:

(millions of dollars)		Three months ended September 30		Nine months ended September 30	
Related Party	**Transaction**	**2017**	**2016**	**2017**	**2016**
IESO	Power purchased	276	460	1,169	1,505
	Revenues for transmission services	390	434	1,124	1,185
	Amounts related to electricity rebates	181	—	321	—
	Distribution revenues related to rural rate protection	61	31	185	94
	Distribution revenues related to the supply of electricity to remote northern communities	8	8	24	24
	Funding received related to Conservation and Demand Management programs	18	15	44	39
OPG	Power purchased	2	1	7	4
	Revenues related to provision of construction and equipment maintenance services	—	2	1	3
	Costs expensed related to the purchase of services	—	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	—	1	1
OEB	OEB fees	2	2	6	9
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	—	—	2
Hydro One Limited	Return of stated capital	129	129	405	480
	Dividends paid	5	—	11	2
	Stock-based compensation costs	6	7	18	18
Hydro One Telecom	Service received - costs expensed	6	6	18	19
	Service received - costs capitalized	—	3	—	9
	Revenues for services provided	1	—	2	—

RISK FACTORS

Risk associated with change in Hydro One Limited capital structure

A change in the capital structure of Hydro One Limited could cause credit rating agencies which rate the outstanding debt obligations of Hydro One to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the Company's 2016 annual MD&A.

Together, disclosure controls and procedures and internal control over financial reporting make up the systems that provide internal control over reporting and disclosure. These systems include policies and procedures designed to enable the reliability and timeliness of information disclosed by the Company. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior finance executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until a new Chief Financial Officer is appointed. There have been no other significant changes in the design of the Company's internal control over financial reporting during the nine months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – September 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed during the fourth quarter of 2017. The Company is on track for implementation of this standard by the effective date.
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; collective agreements; Inergi outsourcing and customer service operations arrangements; future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; credit ratings; non-GAAP measures; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; and the Company's acquisitions, including Orillia Power. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One's parent corporation and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in the 2016 MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE INC.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

For the three and nine months ended September 30, 2017 and 2016

(millions of Canadian dollars, except per share amounts)	Three months ended September 30 2017	Three months ended September 30 2016	Nine months ended September 30 2017	Nine months ended September 30 2016
Revenues				
Distribution (includes related party revenues of $69 (2016 – $39) and $209 (2016 – $120) for the three and nine months ended September 30, respectively) *(Note 20)*	1,040	1,249	3,317	3,687
Transmission (includes related party revenues of $391 (2016 – $435) and $1,127 (2016 – $1,187) for the three and nine months ended September 30, respectively) *(Note 20)*	471	444	1,201	1,211
	1,511	1,693	4,518	4,898
Costs				
Purchased power (includes related party costs of $278 (2016 – $461) and $1,177 (2016 – $1,510) for the three and nine months ended September 30, respectively) *(Note 20)*	675	870	2,213	2,569
Operation, maintenance and administration *(Note 20)*	252	258	784	760
Depreciation and amortization *(Note 4)*	207	189	597	568
	1,134	1,317	3,594	3,897
Income before financing charges and income taxes	377	376	924	1,001
Financing charges	104	98	310	291
Income before income taxes	273	278	614	710
Income taxes *(Note 5)*	31	43	79	107
Net income	**242**	**235**	**535**	**603**
Other comprehensive income	—	—	1	—
Comprehensive income	**242**	**235**	**536**	**603**
Net income attributable to:				
Noncontrolling interest	1	2	4	4
Common shareholder	241	233	531	599
	242	**235**	**535**	**603**
Comprehensive income attributable to:				
Noncontrolling interest	1	2	4	4
Common shareholder	241	233	532	599
	242	**235**	**536**	**603**
Earnings per common share *(Note 18)*				
Basic	$1,694	$1,638	$3,733	$4,211
Diluted	$1,694	$1,638	$3,733	$4,211
Dividends per common share declared *(Note 17)*	$35	—	$77	$14

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

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HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS (unaudited)
At September 30, 2017 and December 31, 2016

(millions of Canadian dollars)	September 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	90	48
Accounts receivable *(Note 6)*	587	833
Due from related parties	447	224
Other current assets *(Note 7)*	116	97
	1,240	1,202
Property, plant and equipment *(Note 8)*	19,659	19,068
Other long-term assets:		
Regulatory assets	3,147	3,145
Deferred income tax assets	1,019	1,213
Intangible assets (net of accumulated amortization – $357; 2016 – $330)	359	349
Goodwill	327	327
Other assets	6	6
	4,858	5,040
Total assets	**25,757**	**25,310**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 12)*	894	469
Long-term debt payable within one year *(Notes 12, 13)*	602	602
Accounts payable and other current liabilities *(Note 10)*	939	933
Due to related parties	170	253
	2,605	2,257
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 12, 13)*	10,067	10,078
Regulatory liabilities	127	209
Deferred income tax liabilities	65	60
Other long-term liabilities *(Note 11)*	2,836	2,765
	13,095	13,112
Total liabilities	**15,700**	**15,369**
Contingencies and Commitments (Notes 22, 23)		
Subsequent Events (Notes 9, 25)		
Noncontrolling interest subject to redemption	22	22
Equity		
Common shares *(Note 16)*	4,986	5,391
Retained earnings	5,007	4,487
Accumulated other comprehensive loss	(8)	(9)
Hydro One shareholder's equity	9,985	9,869
Noncontrolling interest	50	50
Total equity	**10,035**	**9,919**
	25,757	**25,310**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (unaudited)
For the nine months ended September 30, 2017 and 2016

Nine months ended September 30, 2017 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2017	5,391	4,487	(9)	9,869	50	9,919
Net income	—	531	—	531	3	534
Other comprehensive income	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	(3)	(3)
Dividends on common shares	—	(11)	—	(11)	—	(11)
Return of stated capital	(405)	—	—	(405)	—	(405)
September 30, 2017	**4,986**	**5,007**	**(8)**	**9,985**	**50**	**10,035**

Nine months ended September 30, 2016 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest	Total Equity
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	—	599	—	599	3	602
Distributions to noncontrolling interest	—	—	—	—	(5)	(5)
Dividends on common shares	—	(2)	—	(2)	—	(2)
Return of stated capital	(480)	—	—	(480)	—	(480)
September 30, 2016	**5,520**	**4,356**	**(9)**	**9,867**	**50**	**9,917**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

HYDRO ONE INC.
CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
For the three and nine months ended September 30, 2017 and 2016

	Three months ended September 30		Nine months ended September 30	
(millions of Canadian dollars)	2017	2016	2017	2016
Operating activities				
Net income	242	235	535	603
Environmental expenditures	(7)	(5)	(19)	(15)
Adjustments for non-cash items:				
Depreciation and amortization (excluding asset removal costs)	185	168	531	500
Regulatory assets and liabilities	(32)	(6)	92	(28)
Deferred income taxes	25	33	62	90
Other	—	6	1	6
Changes in non-cash balances related to operations *(Note 21)*	19	104	(45)	31
Net cash from operating activities	432	535	1,157	1,187
Financing activities				
Long-term debt issued	—	—	—	1,350
Long-term debt repaid	—	—	(1)	(450)
Short-term notes issued	1,232	940	2,810	2,435
Short-term notes repaid	(1,053)	(770)	(2,385)	(2,808)
Return of stated capital	(129)	(129)	(405)	(480)
Dividends paid	(5)	—	(11)	(2)
Distributions paid to noncontrolling interest	(1)	(3)	(4)	(7)
Change in bank indebtedness	(13)	(34)	—	0
Other	—	—	—	(6)
Net cash from financing activities	31	4	4	32
Investing activities				
Capital expenditures *(Note 21)*				
Property, plant and equipment	(356)	(397)	(1,063)	(1,152)
Intangible assets	(24)	(15)	(57)	(43)
Acquisitions	—	(3)	—	(3)
Capital contributions received	—	—	9	15
Other	—	3	(8)	3
Net cash used in investing activities	(380)	(412)	(1,119)	(1,180)
Net change in cash and cash equivalents	83	127	42	39
Cash and cash equivalents, beginning of period	7	1	48	89
Cash and cash equivalents, end of period	**90**	**128**	**90**	**128**

See accompanying notes to Condensed Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Earnings for interim periods may not be indicative of results for the year due to the impact of seasonal weather conditions on customer demand and market pricing.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited condensed interim Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) for interim financial statements and in Canadian dollars.

The accounting policies applied are consistent with those outlined in Hydro One's annual audited consolidated financial statements for the year ended December 31, 2016. These Consolidated Financial Statements reflect adjustments, that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 annual audited consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Under assessment
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – September 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of its regulated distribution and transmission revenue streams and has concluded that there will be no significant impact to these revenue streams upon adoption. The Company continues its assessment of all other revenue streams and expects to be completed during the fourth quarter of 2017. The Company is on track for implementation of this standard by the effective date.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02	February 2016	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.

4. DEPRECIATION AND AMORTIZATION

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Depreciation of property, plant and equipment	162	149	467	444
Asset removal costs	22	21	66	68
Amortization of intangible assets	16	14	45	41
Amortization of regulatory assets	7	5	19	15
	207	189	597	568

5. INCOME TAXES

Income taxes differ from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

	Nine months ended September 30	
(millions of dollars)	2017	2016
Income taxes at statutory rate	163	188
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(38)	(41)
Pension contributions in excess of pension expense	(11)	(13)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(12)
Interest capitalized for accounting but deducted for tax purposes	(13)	(14)
Environmental expenditures	(6)	(5)
Prior years' adjustments	(4)	1
Other	(3)	1
Net temporary differences	(87)	(83)
Net permanent differences	3	2
Total income taxes	79	107
Effective income tax rate	12.9%	15.1%

6. ACCOUNTS RECEIVABLE

(millions of dollars)	September 30, 2017	December 31, 2016
Accounts receivable – billed	288	427
Accounts receivable – unbilled	330	441
Accounts receivable, gross	618	868
Allowance for doubtful accounts	(31)	(35)
Accounts receivable, net	587	833

The following table shows the movements in the allowance for doubtful accounts for the nine months ended September 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Nine months ended September 30, 2017	Year ended December 31, 2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	18	37
Additions to allowance for doubtful accounts	(14)	(11)
Allowance for doubtful accounts – ending	(31)	(35)

7. OTHER CURRENT ASSETS

(millions of dollars)	September 30, 2017	December 31, 2016
Regulatory assets	58	37
Materials and supplies	19	19
Prepaid expenses and other assets	39	41
	116	97

8. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)	September 30, 2017	December 31, 2016
Property, plant and equipment	28,137	27,523
Less: accumulated depreciation	(10,152)	(9,832)
	17,985	17,691
Construction in progress	1,509	1,223
Future use land, components and spares	165	154
	19,659	19,068

9. REGULATORY ASSETS AND LIABILITIES

Deferred Income Tax Regulatory Asset

On September 28, 2017, the Ontario Energy Board (OEB) issued its Decision and Order on Hydro One Networks Inc.'s (Hydro One Networks) 2017 and 2018 transmission rates revenue requirements (Decision).

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax to the Ontario Electricity Financial Corporation (OEFC) Regime to the Federal Tax Regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. The OEB proposed a basis for sharing a portion of the tax savings resulting from the deferred tax asset with ratepayers by reducing the amount of cash taxes approved for recovery in Hydro One Networks' 2017-2018 transmission rates. On November 9, 2017, the OEB issued a Decision and Order that modified the portion of the tax savings that should be shared with ratepayers. This proposed methodology would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same methodology for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an impairment of Hydro One Networks' distribution deferred income tax regulatory asset of up to approximately $370 million. In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The outcome of the Motion to Review and Vary as well as the Appeal are uncertain. If the decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million.

10. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(millions of dollars)	September 30, 2017	December 31, 2016
Accounts payable	154	177
Accrued liabilities	596	651
Accrued interest	131	105
Regulatory liabilities	58	—
	939	933

11. OTHER LONG-TERM LIABILITIES

(millions of dollars)	September 30, 2017	December 31, 2016
Post-retirement and post-employment benefit liability	1,688	1,628
Pension benefit liability	899	900
Environmental liabilities *(Note 15)*	174	177
Due to related parties	34	26
Asset retirement obligations	9	9
Long-term accounts payable and other liabilities	32	25
	2,836	2,765

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One’s committed revolving credit facilities totalling $2.3 billion. In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

Long-Term Debt

The following table presents long-term debt outstanding at September 30, 2017 and December 31, 2016:

(millions of dollars)	September 30, 2017	December 31, 2016
Hydro One long-term debt *(a)*	10,523	10,523
HOSSM long-term debt *(b)*	179	184
	10,702	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[1]	(9)	(2)
Less: Deferred debt issuance costs	(38)	(40)
Total long-term debt	10,669	10,680
Less: Long-term debt payable within one year	(602)	(602)
	10,067	10,078

[1] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and the $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (December 31, 2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One long-term debt

At September 30, 2017, long-term debt of $10,523 million (December 31, 2016 - $10,523 million) was outstanding under Hydro One’s MTN Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At September 30, 2017, $1.2 billion remained available for issuance until January 2018. During the nine months ended September 30, 2017, no long-term debt was issued or repaid under the MTN Program (2016 - $1,350 million issued and $450 million repaid).

(b) Hydro One Sault Ste. Marie. (HOSSM) long-term debt

At September 30, 2017, long-term debt related to HOSSM was $179 million (December 31, 2016 - $184 million), with a face value of $147 million. During the nine months ended September 30, 2017, $1 million of HOSSM long-term debt was repaid.

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	602	5.2
2 years	981	2.6
3 years	1,153	2.3
4 years	503	1.9
5 years	603	3.2
	3,842	2.9
6 – 10 years	633	3.5
Over 10 years	6,195	5.2
	10,670	4.3

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
Remainder of 2017	141
2018	426
2019	402
2020	384
2021	370
	1,723
2022-2026	1,703
2027+	4,405
	7,831

13. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Non-Derivative Financial Assets and Liabilities

At September 30, 2017 and December 31, 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at September 30, 2017 and December 31, 2016 are as follows:

	September 30, 2017		December 31, 2016	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	10,128	11,328	10,132	11,462
Long-term debt, including current portion	10,669	11,869	10,680	12,010

Fair Value Measurements of Derivative Instruments

At September 30, 2017, Hydro One had interest-rate swaps in the amount of $550 million (December 31, 2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One's fair value hedge exposure was approximately 5% (December 31, 2016 – 5%) of its total long-term debt. At September 30, 2017, Hydro One had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At September 30, 2017 and December 31, 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at September 30, 2017 and December 31, 2016 is as follows:

September 30, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	90	90	90	—	—
	90	90	90	—	—
Liabilities:					
Short-term notes payable	894	894	894	—	—
Long-term debt, including current portion	10,669	11,869	—	11,869	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
	11,572	12,772	903	11,869	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	48	48	48	—	—
	48	48	48	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the nine months ended September 30, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the three and nine months ended September 30, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the three and nine months ended September 30, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At September 30, 2017 and December 31, 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At September 30, 2017 and December 31, 2016, there was no material accounts receivable balance due from any single customer.

At September 30, 2017, the Company's provision for bad debts was $31 million (December 31, 2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At September 30, 2017, approximately 6% (December 31, 2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At September 30, 2017 and December 31, 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At September 30, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Defined Benefit Pension Plan, Supplementary Pension Plan, and Post-Retirement and Post-Employment Plans

Estimated annual defined benefit pension plan contributions for 2017, 2018 and 2019 are approximately $88 million, $71 million, and $71 million, respectively, based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Employer contributions made during the nine months ended September 30, 2017 were $67 million (2016 – $83 million).

The following tables provide the components of the net periodic benefit costs for the three and nine months ended September 30, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Three months ended September 30 *(millions of dollars)*	**2017**	**2016**	**2017**	**2016**
Current service cost	36	36	11	10
Interest cost	76	77	17	17
Expected return on plan assets, net of expenses[1]	(110)	(109)	—	—
Actuarial loss amortization	20	24	2	2
Net periodic benefit costs	22	28	30	29
Charged to results of operations[2]	10	13	14	13

Nine months ended September 30 *(millions of dollars)*	Pension Benefits		Post-Retirement and Post-Employment Benefits	
	2017	2016	2017	2016
Current service cost	109	108	35	31
Interest cost	228	231	50	50
Expected return on plan assets, net of expenses[1]	(331)	(326)	—	—
Actuarial loss amortization	60	72	6	6
Net periodic benefit costs	66	85	91	87
Charged to results of operations[2]	30	38	40	37

[1] The expected long-term rate of return on pension plan assets for the year ending December 31, 2017 is 6.5% (2016 – 6.5%).

[2] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the three and nine months ended September 30, 2017, pension costs of $22 million (2016 – $29 million) and $67 million (2016 – $86 million), respectively, were attributed to labour, of which $10 million (2016 – $13 million) and 30 million (2016 – $38 million), respectively, were charged to operations, and $12 million (2016 – $16 million) and $37 million (2016 – $48 million) respectively, were capitalized as part of the cost of property, plant and equipment and intangible assets.

15. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the nine months ended September 30, 2017 and the year ended December 31, 2016:

(millions of dollars)	Nine months ended September 30, 2017	Year ended December 31, 2016
Environmental liabilities – beginning	204	207
Interest accretion	6	8
Expenditures	(19)	(20)
Revaluation adjustment	11	9
Environmental liabilities – ending	202	204
Less: current portion	(28)	(27)
	174	177

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

(millions of dollars)	September 30, 2017	December 31, 2016
Undiscounted environmental liabilities	214	224
Less: discounting environmental liabilities to present value	(12)	(20)
Discounted environmental liabilities	202	204

Future expenditures have been discounted using rates ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. At September 30, 2017, the estimated undiscounted future environmental expenditures were as follows:

(millions of dollars)	
2017 [1]	8
2018	25
2019	25
2020	30
2021	37
Thereafter	89
	214

[1] The amounts disclosed represent amounts for the period from October 1, 2017 to December 31, 2017.

16. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At September 30, 2017 and December 31, 2016, the Company had 142,239 common shares issued and outstanding.

During the three and nine months ended September 30, 2017, the Company returned stated capital of $129 million (2016 – $129 million) and $405 million (2016 – $480 million), respectively.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At September 30, 2017 and December 31, 2016, Hydro One had no issued and outstanding preferred shares.

17. DIVIDENDS

During the three and nine months ended September 30, 2017, common share dividends in the amount of $5 million (2016 – $nil) and $11 million (2016 – $2 million), respectively, were declared and paid.

18. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding during the three and nine months ended September 30, 2017 was 142,239 (2016 - 142,239). There were no dilutive securities during the three and nine months ended September 30, 2017 and 2016.

19. STOCK-BASED COMPENSATION

Share Grant Plans

A summary of share grant activity under the Share Grant Plans during the three and nine months ended September 30, 2017 and 2016 is presented below:

	Three months ended September 30		Nine months ended September 30	
(number of share grants)	2017	2016	2017	2016
Share grants outstanding - beginning	4,870,412	5,319,370	5,239,678	5,319,370
Vested[1]	—	—	(369,266)	—
Share grants outstanding - ending	4,870,412	5,319,370	4,870,412	5,319,370

[1] On April 1, 2017, Hydro One Limited issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the Power Workers' Union Share Grant Plan.

Directors' Deferred Share Units (DSU) Plan

During the three and nine months ended September 30, 2017 and 2016, the Company granted awards under its Directors' DSU Plan, as follows:

	Three months ended September 30		Nine months ended September 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	141,553	59,205	99,083	20,525
DSUs granted	22,504	18,922	64,974	57,602
DSUs outstanding – ending	164,057	78,127	164,057	78,127

At September 30, 2017, a liability of $4 million (December 31, 2016 – $2 million) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.72 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Company's Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the three and nine months ended September 30, 2017 and 2016, the Company granted awards under its Management DSU Plan, as follows:

	Three months ended September 30		Nine months ended September 30	
(number of DSUs)	2017	2016	2017	2016
DSUs outstanding – beginning	63,593	—	—	—
DSUs granted	618	—	64,211	—
DSUs outstanding – ending	64,211	—	64,211	—

At September 30, 2017, a liability of $2 million (December 31, 2016 – $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.72 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Long-term Incentive Plan

During the three and nine months ended September 30, 2017 and 2016, Hydro One Limited granted awards under its Long-term Incentive Plan (LTIP), consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled in Hydro One Limited shares, as follows:

	PSUs		RSUs	
Three months ended September 30 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	438,235	122,410	404,355	147,410
Units granted	35,790	103,270	21,040	101,820
Units vested	(609)	—	(609)	—
Units forfeited	(9,036)	(1,730)	(7,676)	(1,730)
Units outstanding - ending	464,380	223,950	417,110	247,500

	PSUs		RSUs	
Nine months ended September 30 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	228,890	—	252,440	—
Units granted	300,090	225,680	236,410	249,230
Units vested	(609)	—	(14,079)	—
Units forfeited	(63,991)	(1,730)	(57,661)	(1,730)
Units outstanding - ending	464,380	223,950	417,110	247,500

The grant date total fair value of the awards granted during the three and nine months ended September 30, 2017 was $1 million and $13 million (2016 – $5 million and $12 million), respectively. The compensation expense recognized by the Company relating to LTIP awards during the three and nine months ended September 30, 2017 was $2 million and $5 million (2016 – $1 million and $1 million), respectively.

20. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 49.9% ownership at September 30, 2017. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), OEFC, the OEB, and Hydro One Telecom Inc. (Hydro One Telecom) are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

(millions of dollars)		Three months ended September 30		Nine months ended September 30	
Related Party	Transaction	2017	2016	2017	2016
IESO	Power purchased	276	460	1,169	1,505
	Revenues for transmission services	390	434	1,124	1,185
	Amounts related to electricity rebates	181	—	321	—
	Distribution revenues related to rural rate protection	61	31	185	94
	Distribution revenues related to the supply of electricity to remote northern	8	8	24	24
	Funding received related to Conservation and Demand Management programs	18	15	44	39
OPG	Power purchased	2	1	7	4
	Revenues related to provision of construction and equipment maintenance	—	2	1	3
	Costs expensed related to the purchase of services	—	—	1	1
OEFC	Power purchased from power contracts administered by the OEFC	—	—	1	1
OEB	OEB fees	2	2	6	9
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	—	—	2
Hydro One Limited	Return of stated capital	129	129	405	480
	Dividends paid	5	—	11	2
	Stock-based compensation costs	6	7	18	18
Hydro One Telecom	Service received - costs expensed	6	6	18	19
	Service received - costs capitalized	—	3	—	9
	Revenues for services provided	1	—	2	—

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Accounts receivable	49	(15)	239	—
Due from related parties	(81)	(10)	(223)	(42)
Materials and supplies	—	2	—	3
Prepaid expenses and other assets	8	16	2	(14)
Accounts payable	(12)	(7)	(9)	14
Accrued liabilities	(16)	(6)	(55)	19
Due to related parties	23	90	(85)	(27)
Accrued interest	28	19	26	24
Long-term accounts payable and other liabilities	(1)	(2)	—	2
Post-retirement and post-employment benefit liability	21	17	60	52
	19	104	(45)	31

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Capital investments in property, plant and equipment	(357)	(405)	(1,079)	(1,171)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	1	8	16	19
Cash outflow for capital expenditures – property, plant and equipment	(356)	(397)	(1,063)	(1,152)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Capital investments in intangible assets	(21)	(17)	(49)	(45)
Net change in accruals included in capital investments in intangible assets	(3)	2	(8)	2
Cash outflow for capital expenditures – intangible assets	(24)	(15)	(57)	(43)

Supplementary Information

	Three months ended September 30		Nine months ended September 30	
(millions of dollars)	2017	2016	2017	2016
Net interest paid	89	89	308	291
Income taxes paid	3	10	10	23

22. CONTINGENCIES

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

23. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

September 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	118	93	25	2	7	2
Long-term software/meter agreement	17	17	17	6	1	3
Operating lease commitments	10	7	9	3	2	2

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

September 30, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	—	2,300	—
Letters of credit[1]	165	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $150 million letter of credit related to retirement compensation arrangements, an $8 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

24. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Three months ended September 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	471	1,040	—	1,511
Purchased power	—	675	—	675
Operation, maintenance and administration	98	151	3	252
Depreciation and amortization	105	102	—	207
Income (loss) before financing charges and income taxes	268	112	(3)	377
Capital investments	240	138	—	378

Three months ended September 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	444	1,249	—	1,693
Purchased power	—	870	—	870
Operation, maintenance and administration	97	162	(1)	258
Depreciation and amortization	96	93	—	189
Income before financing charges and income taxes	251	124	1	376
Capital investments	241	181	—	422

Nine months ended September 30, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,201	3,317	—	4,518
Purchased power	—	2,213	—	2,213
Operation, maintenance and administration	307	452	25	784
Depreciation and amortization	309	288	—	597
Income (loss) before financing charges and income taxes	585	364	(25)	924
Capital investments	701	427	—	1,128

Nine months ended September 30, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,211	3,687	—	4,898
Purchased power	—	2,569	—	2,569
Operation, maintenance and administration	295	451	14	760
Depreciation and amortization	285	283	—	568
Income (loss) before financing charges and income taxes	631	384	(14)	1,001
Capital investments	714	502	—	1,216

Total Assets by Segment:

(millions of dollars)	September 30, 2017	December 31, 2016
Transmission	13,520	13,083
Distribution	9,338	9,393
Other	2,899	2,834
Total assets	25,757	25,310

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. SUBSEQUENT EVENTS

Dividends and Return of Stated Capital

On November 9, 2017, common share dividends in the amount of $5 million were declared, and a return of stated capital in the amount of $129 million was approved.

Repayment of Long-term Debt

On October 18, 2017, Hydro One repaid $600 million of maturing long-term debt notes (MTN Series 13 notes) under its MTN Program.

Issuance of Promissory Note

On October 17, 2017, Hydro One issued a $486 million promissory note payable on demand to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, with a floating interest rate referenced to the 3-month Canadian dollar bankers' acceptance rate.