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

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

BY E-MAIL

January 19, 2018

Ms. Eryn Henderson
Senior Regulatory Coordinator
Regulatory Affairs
Hydro One Networks Inc.
7th Floor South Tower
483 Bay Street
Toronto, ON M5G 2P5

Dear Ms. Henderson:

Re: Hydro One Networks Inc.
Distribution Rates Application, 2018 - 2022
Board File Number, EB-2017-0049
OEB staff Interrogatories

Please find attached, OEB staff Interrogatories for this proceeding. The interrogatories are listed by issue in accord with the Approved Issues List.

Yours truly,

Original signed by

Harold Thiessen
Ontario Energy Board staff
Case Manager, EB-2017-0049

Hydro One Networks Inc.
EB-2017-0049 Distribution Rates Application, 2018 - 2022
OEB staff Interrogatories
January 19, 2018

A. GENERAL

Issue 1. Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Issue 2. Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

OEB staff A2-1
Ref: Executive Presentation Day Transcript, page 38
At this page Mr. Pugliese indicates that,

> *"…one year after some of this work has started, is that the changes have resulted in a reduction of 100,000 calls related to billing and 73,000 fewer calls related to affordability, and we actually see that trend continuing to drop in terms of our responses back to the call centre*."

Please provide a table that shows the reductions in customer calls on a monthly basis broken down by category of calls.

OEB staff A2-2
Ref: Executive Presentation Day Transcript, page 41
At this page Mr. Pugliese testifies,

> "….we are the first utility to offer service guarantees. So, if we make a commitment to do a reconnect, to do a move in and move-out, if we fail to meet that within a set time frame, there is a service guarantee that we will give to the customer and a credit, and that is $75.

a) Please provide a list of the services that Hydro One's "service guarantee" would cover.
b) Please describe in detail how this service guarantee would work for a typical customer.
c) Are there specific criteria the customer must meet to qualify for this service guarantee?
d) What is the total amount budgeted for 2018 for this service guarantee credit?

OEB staff A2-3
Ref: Executive Presentation Day Transcript, page 41
At this reference, Mr. Pugliese indicated that Hydro One had returned $12 million in security deposit value back to customers.

Section 2.4.9 of the Distribution System Code (DSC) sets out the circumstances under which a distributor may require a security deposit for different classes of customers. Sections 2.4.22 – 2.4.25 set out the process for the review and adjustment or return of security deposits.

a) Please confirm that the security deposit amounts returned to customers were not held by Hydro One for periods longer than those set out in the DSC. If this cannot be confirmed, please provide an explanation.

b) Please confirm whether these security deposits were returned earlier than the time periods set out in the DSC. If so, please provide:

   i. Hydro One's time period for returning the deposit by customer class.
   ii. The reasons for returning these customer deposits and how Hydro One addressed the payment risk that a security deposit represents.

c) Has Hydro One made a permanent adjustment to its security deposit policy and defined its new criteria formally? If so, please provide the policy and outline how it is has changed.

OEB staff A2-4
Ref: Executive Presentation Day Transcript, page 42-43
At this reference, Mr. Pugliese indicated that Hydro One had changed its collections process from 4 stages to 8 stages. He also indicated that in 2014 accounts receivable were $194 million, which were reduced to $86 million in the most recent quarter of 2016.

a) Please provide an update to reflect the most recent quarterly amount.
b) Please provide a more detailed account of how the collections process was changed, what the additional stages are and why this has resulted in lower levels of overdue accounts.
c) Please provide a more detailed accounting of the reduction in accounts receivable balances with a table which shows the trend of the reductions.

OEB staff A2-5
Ref: Executive Presentation Day Transcript, page 43
At this reference, Mr. Pugliese indicated that Hydro One reconnected 400 dwellings that were inhabited of the 1,400 dwellings that had been disconnected. In addition, he testified that 60% of these dwellings are still connected today.

Please provide a more detailed account of how this process was conducted and the key aspects or learnings for Hydro One in conducting this exercise.

OEB staff A2-6
Ref: Executive Presentation Day Transcript, page 49

At this reference, Mr. Pugliese indicated that Hydro One will be introducing customer-selected due dates allowing the customer to select the due date by which it wants to pay the bill in the given month.

a) Please indicate whether this option will be available to all customer classes. If not, please identify the classes to which it will be made available and explain why it would not be universally available.

b) Would this require a major adjustment to Hydro One's billing system to meet the customer's request for a specific due date and to also meet the requirements of section 2.6 of the Distribution System Code – Bill Issuance and Payment.

c) Are there incremental OM&A costs involved in this change?

OEB staff A2-7
Ref: Executive Presentation Day Transcript, page 49-50 and Exhibit B/Part B/ISD GP-31 (Prepaid Meters)

At the Presentation Day, Mr. Pugliese indicated that Hydro One would never force the pre-paid meter option on any customer and that some customers have requested the pre-paid meter option and others have shown a preference for the load limiter option. At Exhibit B, Hydro One has indicated that it plans to commit $6.1 million in capital to a pre-paid meter project in 2022.

a) Please indicate the degree to which customers prefer the prepaid meter and load limiter options, and in particular:

   i) How many customers have requested prepaid meters? Were these requests unsolicited? What were the circumstances under which the requests were made?
   ii) How many customers have provided unsolicited requests to have a load limiters installed?
   iii) How many customers have provided unsolicited requests to keep a load limiter in lieu of complete reconnection?
   iv) What is Hydro One's current policy on the use of load limiters? Would this policy change under the proposed pre-paid meter program?

b) How will the planned prepaid meter program work in order to allow alternate arrangements to be made for payments (e.g. arrears management plans)?

c) Currently the LEAP program is designed to help pay arrears and maintain connection. It is generally accessed once the consumer receives a disconnection notice. If the consumer is on pre-paid meter service, how would the LEAP be used to provide credits to keep the electricity on?

d) Assuming that the meter would automatically disconnect when the credits run out, how would this be consistent with the disconnection requirements in the various codes and any legislative and/or regulatory restrictions on disconnections in the winter months?

e) How would this program work for special situations such as customers that have specific medical needs for electricity service?

f) What is the rationale for introducing the pre-paid meter program in 2022?

g) Section 53.16(1) of the *Electricity Act* in association with O. Reg. 525/06 states that when a distributor replaces an existing meter for residential or general service customers, the meter must meet the Functional Specification for Advanced Metering Infrastructure. Will these pre-paid meters meet the “functional specifications”? If not, how will Hydro One resolve this conflict?

h) Section 3.4 of the Standard Supply Service Code states that customers with eligible time-of-use meters must be charged using time-of-use pricing. Will these pre-paid meters be able to charge customers based on time-of-use pricing? If not, how will Hydro One resolve this conflict?

i) If pre-paid meters were to charge based on time-of-use, how would customers reasonably be able to calculate the amount of pre-paid credit required and/or available to cover a specific period given changes in pricing, use and timing?

j) Would pre-paid meters be able to shift between pre-paid mode and “regular” mode to ensure a consumer was not effectively disconnected during winter if unable to purchase new credits?

k) How would consumers “purchase” credits for pre-paid meters? If it is internet based, has Hydro One taken into consideration the complexities and service issues associated with internet access in remote communities? If consumers are able to purchase via credit card, has Hydro One taken into account the limitations on access to credit cards for lower income households?

l) How would fixed charges, such as the monthly delivery fee, be billed for pre-paid meter customers? If a pre-paid meter customer did not use any electricity in the month, would they still be charged a monthly delivery fee?

m) How would OESP and/or any other similar support programs be applied for customers with pre-paid meters?

n) Has Hydro One undertaken a risk-analysis to identify potential issues with pre-paid meters? If so, please provide details on what risks were identified and any action plans Hydro One has developed to mitigate these risks.

OEB staff A2-8
Ref: Executive Presentation Day Transcript, page 44
At this reference, Mr. Pugliese indicated that Hydro One had just launched a new bill design. Please provide a copy of the new bill, description of the new bill presentation and outline the changes made and why those changes were made. Please also provide initial customer feedback, if available, on the new bill design.

OEB staff A2-9
Ref: Executive Presentation Day Transcript, page 18 and page 44 and Exhibit C1/Tab 1/Schedule 5, pg 13, Table 11: Operational Effectiveness Outcomes
As noted above, Hydro One witnesses mention the bill redesign and its launch in late 2017. Table 11 indicates that the redesign "will make it easier for customers to understand their bill and increase their understanding of their electricity consumption."

a) The Hydro One witness mentioned that 40% of customers found that the current bill was confusing. What was the source of this statement?

b) Were there additional reasons for pursuing a bill redesign?

c) Please summarize the changes made to the bill design and why each specific change was made.

d) What was the cost of this bill redesign and are any of the costs of this project proposed to be recovered in 2018 rates?

e) What are the benefits expected from this bill redesign? Is customer satisfaction expected to improve? If so, by what amount? Are call volumes expected to be lower? Again by what amount? Would this lead to lower staffing and other costs and if so, to what extent?

f) Have bills also been redesigned for General Service and Large User customers? If so, what was the rational for this redesign and what are the benefits expected?

g) As Hydro One has shared this bill redesign with other distributors, what is the status of the bill redesign project in the distribution sector?

h) After the 2017 bill redesign completed in 2017, why is Hydro One planning another bill redesign for 2021/2022, as shown at ISD GP-29 (Customer Service Billing Investments)? What additional features are planned in the 2021/2022 redesign not already in 2017 redesign?

Issue 3. Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Regulatory Taxes

OEB staff A3-10
Ref: Exhibit C1/Tab7/Schedule 2, Attachment 1
At the above reference, Hydro One calculates the test period regulatory taxes sought for recovery in rates. On December 21, 2017, Hydro One filed Exhibit Q which provided updates to various areas of the previously filed evidence for this proceeding. As part of this update, Hydro One indicated a change to the regulatory tax balance being sought for recovery, however did not provide an updated detailed tax calculation in support of the revised amounts.

> Please provide an updated regulatory tax calculation for the test period similar to the one provided in Exhibit C1/Tab7/Schedule 2, Attachment 1. Also please update other regulatory tax supporting documents as needed as a result of changes noted in Exhibit Q (i.e. CCA)

OEB staff A3-11
Ref: Exhibit C1/Tab7/Schedule 3
At the above reference, Hydro One indicated that its 2016 Income Tax Return will be submitted as an update to the application once complete, however to date it has not been submitted.

> Please provide the final (filed) Income Tax Return for 2016.

OEB staff A3-12
Ref: Exhibit C1/Tab7/Schedule 3/December 31, 2015 Tax Return, Schedule 4
Schedule 4 of the December 31, 2015 Tax Return indicates that Hydro One has significant non-capital loss carryforwards.

> Please explain how these losses have been considered in the calculation of regulatory taxes for the test period.

OEB staff A3-13
Ref: Exhibit C1/Tab7/Schedule 3/December 31, 2015 Tax Return, Schedule 10
Schedule 10 of the December 31, 2015 tax return indicates that Hydro One is eligible to receive a significant annual CEC deduction.

> Although Hydro One does consider a CEC deduction in their calculation of the test period regulatory taxes, the deduction being allocated to the regulatory tax

calculation is significantly less compared to what is available as per Schedule 10. Please explain why.

Issue 4. Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Issue 5. Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?

Issue 6. Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

OEB staff A6-14
Ref: Executive Presentation Day Transcript, page 47
At this reference, Mr. Pugliese indicated that Hydro One has met with over 1,500 First Nations customers in their communities and has helped decrease customer arrears in those communities by 24 percent year over year.

a) Does Hydro One have a special collections program for customers in the First Nations Communities? If yes, please provide the details of this program and how it differs from the standard program.

b) Does Hydro One forecast further improvement in customer arrears reductions?

OEB staff A6-15
Ref: Exhibit A/Tab4/Schedule 2 and Exhibit C1/Tab1/Schedule 7, pp 16-17
At this reference, Hydro One summarizes its First Nations and Metis Strategy and lists a number of initiatives and undertakings with First Nations.

a) Has Hydro One instituted a specific scorecard that measures its success in its dealings with First Nations on a general level and also with regard to specific initiatives? If so, please provide this scorecard or report.

b) With regard to the new customer service offerings mentioned, please provide a summary of these programs.

OEB staff A6-16
Ref: Exhibit A/Tab4/Schedule 2
In the last Hydro One transmission rate hearing (EB-2016-0160), First Nations concerns were an important part of the proceeding.

Has Hydro One changed or amended any of its First Nations and Metis strategies or practices in its distribution business as a result of the EB-2016-0160 experience?

B. <u>CUSTOM APPLICATION</u>

Issue 7. Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

OEB staff B7-17
Ref: Exhibit A/Tab3/schedule 1/pg 8 and Exhibit A/Tab3/Schedule 2/pg 10
In-Service Capital Additions Variance Account
As part of its Custom IR proposal, Hydro One proposes the establishment of:

> "*A capital in-service variance account to track the cumulative difference over the Term between: (a) the revenue requirement associated with actual in-service capital additions during a rate year; and (b) the revenue requirement associated with the OEB-approved forecast for in-service capital additions for that year; for any capital in-service additions that are 98% or lower than the OEB-approved level; …*"
>
> Further description of the account is provided in Exhibit A/Tab 3/Schedule 2, on page 10 where the second sub-bullet under iii) reads:
>
>> "*Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers."*

a) Please explain exactly what is meant by this. In particular, in a hypothetical scenario where Hydro One's in-service capital additions in each year were 99% of the forecasted capital additions and on which the revenue requirement is determined and used for calculating rates in that year, Hydro One would still recover a revenue requirement higher than actual (since actual capital additions were less than forecasted), assuming that demand and the I – X-adjusted OM&A are the same as forecasted. In the scenario, why would any amount be "recoverable from ratepayers"? Since the account is proposed as being asymmetrical, under what circumstances would a balance be recoverable from customers?

b) Under bullet iii) on page 10 of Exhibit A/Tab3/Schedule 2, it is stated that the disposition of the CISVA account would be at the end of the 5-year term. Under bullet ii), it is stated that: "For **cumulative** in-service additions that are 98% or lower of **the OEB-approved level**, **the associated revenue requirement impact will be computed and reported on an annual basis** in the variance account" [Emphasis added]

The forecasted capital additions vary by each year of the Custom IR term from 2018 to 2022. For 2018, the first year of the plan, it is easy to calculate the variance. However, for successive years, how is the cumulative variance from the (approved) forecasted capital additions calculated? Using examples, please show how this account would work over the five-year Custom IR term.

Issue 8. Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

OEB staff B8-18
Ref: Exhibit A/Tab3/Schedule1/pg 22 – Productivity Savings
Table 6 provides a summary of forecasted savings due to productivity improvements over the five-year test period 2018 to 2022. Above Table 6, Hydro One states:

> *"Specifically, the Company has taken targeted actions to implement productivity improvements as early as 2018, the rebasing year, and intends to achieve further efficiencies over the subsequent four years. While the OEB's RRF provides an incentive for utilities to achieve productivity gains during the Term, such efficiencies ultimately accrue to the benefit of ratepayers at the time of the next rebasing."*

a) Please explain whether the Corporate Common productivity savings are expensed or capitalized.

b) Expenses are "current period" costs. How do productivity savings on expensed costs "ultimately accrue to the benefit of ratepayers at the time of the next rebasing" unless the lower expenses (i.e., inclusive of productivity savings) become the starting point or trend for the forecasting expenses for the test year or test period at the next rebasing?

OEB staff B8-19
Ref: Exhibit A/Tab3/Schedule -1/Attachment 1/Distribution Business Plan 2017-2022/pg 20
At this reference in the Business Plan, Hydro One documents the following savings in pension contributions:

$M	2016	2017	2018
OM&A	16	16	16
Capital	17	17	17
Total	**33**	**33**	**33**

Above the table, Hydro One states:

> "*Hydro One's pension contribution declined for the three years, as follows, allowing reductions in OM&A by $48 million and capital by $51 million for the three years, providing a significant and immediate reduction in customer rates. These savings are in addition to the productivity savings identified in the Productivity Improvements in Business Plan above*."

Following the table, Hydro states:

> *"The capital reductions are offset by additional reinvestment, and the OM&A reductions are included in the OM&A amounts."*

a) Please explain how the pension savings provided reductions in customer rates in 2016 and 2017, and where these savings are factored into the proposed 2018 rates.

b) Please explain what OM&A reductions are factored into the 2018 proposed OM&A amounts. Is it just for the 2018 expensed pension savings?

c) Under Hydro One's Custom IR proposal, OM&A will be adjusted annually for the period 2019 through 2022 inclusive, through the proposed "inflation less productivity" factor. Does Hydro One expect that the Pension contribution savings of $16M, and subject to the I – X formula, to persist beyond 2018?

d) Hydro One will have to have actuarial revaluations done by December 31, 2018 and December 31, 2021, during the proposed Custom IR term. How does Hydro One propose to address material variations in pension contributions if they arise as a result of actuarial revaluations during the Custom IR period?

OEB staff B8-20
Ref: Exhibit A/Tab3/Schedule 1/Attachment 3, pg 9 – Status Report of Auditor-General Action Items
At this reference, Hydro One documents an Advanced Metering Infrastructure for Operations and Analytics (AMIA) project, with a target date for completion of December 31, 2017.

a) Please provide a brief summary of the status of this project.

b) Have any forecasted impacts of this project been reflected in the test period from 2018 to 2022? If yes, please explain where and how these are reflected, and how Hydro One derived the impacts. If not, please provide an explanation.

OEB staff B8-21
Ref: Exhibit A/Tab3/Schedule2/pp 1-2 – Revenue Cap Proposal
Hydro One describes its Custom IR proposal as:

> "*Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5- year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below."*

On page 2, Hydro one gives the formula as:

The Custom Revenue Cap Index (RCI) is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Typically, a revenue cap formula is of the form:

$$Rev_t = Rev_{t-1} \times (1 + (I - X + g))$$

where the I and X are as described above, and g (growth) is based on growth in demand (customers, consumption, energy demand). Revenues are capped by the formula, with rates set to recover the annual revenue requirement updated by this formula.

In Hydro One's proposal, the updated revenue requirement will be converted into rates each year based on the demand forecasted (where forecasted numbers of customers, kWh and kW, as applicable) are used as the billing determinants for the revenue requirement as allocated between customer classes and between fixed and variable charges.

a) Growth in operating scale is an important driver of cost growth. What is the rationale for a revenue cap index that does not include a scale escalator?

b) Please confirm that, under Hydro One's proposal, it has an opportunity, under certain conditions, of earning more revenues than the revenue requirement adjusted by the annual RCI. For example, if actual demand (as a combination of number of customers, kWh and kW) exceeds Hydro One's forecasted demand, Hydro One would receive more revenues as it would be the lower forecasted demand which would be the billing determinants for establishing rates in the year. In the alternative, please explain.

c) Why does Hydro One characterize its proposal as a revenue cap, even though it is little different than Toronto Hydro-Electric System Limited's Custom IR approved in EB-2014-0016, which was characterized there as a Price Cap?

OEB staff B8-22
Ref: Exhibit A/Tab3/Schedule 2/pg 4 – Stretch Factor
Hydro One states:

"The Productivity Factor used in the RCI will not be updated annually over the 2019 to 2022 portion of the Custom IR term. In its total cost benchmarking study, PSE conducted a forward-looking analysis using Hydro One's forecast costs for 2018-2022. This analysis concluded that Hydro One's forecast costs are likely to continue to support a 0.45% stretch factor ranking throughout the incentive rate-setting period."

a) Under the OEB's 2nd and 3rd Generation IRM plans and the current Price Cap IR framework, a utility's ranking for assigning the stretch factor annually depends not only on its performance, but also on the performance of all other Ontario distributors, to gauge how performance in the industry as a whole is changing.

   While PSE may have had Hydro One's forecasted costs, it would not have forecasted costs for other electricity distributors in Ontario, or for other peer utilities in North America. On what basis and with what confidence have PSE and Hydro One concluded that Hydro One's performance will continue to warrant a 0.45% stretch factor throughout the period absent forecasts of how other firms costs are also expected to change in the test period?

b) Under an assumption that the annual benchmarking and assignment of a stretch factor as is currently conducted under direction of the OEB continues throughout the 5-year test period, why should Hydro One's stretch factor not be updated annually?

OEB staff B8-23
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1 - PSE Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry and Attachment 2 – PSE Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network

a) Please provide all working papers associated with the Power Systems Engineering ("PSE") studies titled “Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry” ("Productivity Report") and the updated “Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network” ("Benchmarking Report"). These working papers should include the following:

   i. All data in Excel Format.
   ii. Calculations in Excel format or program code to show the derivation of the results from publicly available data.
   iii. Identification of variable names and company ID numbers.
   iv. Any other information needed for an experienced consultant to be able to replicate the work.

OEB staff's consultant, Pacific Economics Group ("PEG"), agrees to protect any data released by PSE in a manner consistent with agreements PSE may have with data vendors.

b) Were any of the Hydro One data used in the studies provided by Hydro One but are not provided to the OEB via the RRR? If so, please describe, and provide as part of a), identifying such data.

c) On Page 18 of Exhibit A/Tab3/Schedule 2/Attachment 1, PSE states: “PSE made one change to Hydro One’s 2013 data versus what is being used in the 4th Generation IR benchmarking updates and reported in the Yearbooks, based on an inconsistent increase in the reported annual peak demand.” Apart from the 2013 maximum demand adjustment, were any Hydro One data reported on the RRR corrected by Hydro One for use in the PSE study? If so, please explain.

d) Did the 2013-2015 Ontario data used for the TFP calculations include either capital or operations and maintenance (O&M) costs of smart meter installation? Please describe any adjustments made for deferred smart meter capital and/or O&M expenses.

e) Please describe how the data for Hydro One were adjusted to account for the acquisition of Norfolk. Do the Hydro One data include similar data for the Haldimand County and Woodstock acquisitions?

OEB staff B8-24
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1 - PSE Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry and Attachment 2 – PSE Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network - Personnel and Costs

PSE's Productivity Report and Benchmarking Report do not clearly state who authored the reports.

a) Please identify the principal personnel who participated in the productivity and benchmarking studies and reports, briefly summarizing their roles in the projects.

b) What were PSE's fees for these studies?

c) Please provide the terms of engagement or other instructions from Hydro One to PSE for conducting the work of these two studies.

OEB staff B8-25
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pp 3 and 8 – Output Quantity Index

PSE states on page 3 of its Productivity Report that:

> *"The outputs used for the industry TFP trends should also be generally based on billing determinants that are related to how the distributor collects revenue. However, in determining performance, other non-revenue producing, valued outcomes should be incorporated into the evaluation. The condition to have outputs and weights that approximate distribution revenue collection would exclude the use of the adjusted TFP index as the basis for the productivity factor in incentive regulation, even if we had an industry-wide measure of it."*

PSE states on page 8 of the same report that:

> *"[t]he objective for the TFP calculated in the 4th Generation IR proceeding (EB-2010-0379) was to calculate the most appropriate productivity factor to be used in the* ***price*** *cap escalation formula."* [emphasis added]

a) Hydro One's proposed Custom IR plan features a revenue cap index. Trends in billing determinants are widely recognized to be pertinent in the choice of an X factor for a *price* cap index. Please explain why they are also pertinent in the design of an X factor for a *revenue* cap index.

b) Ontario utilities are transitioning to rate designs with high fixed charges for Residential and possibly also for other (e.g., commercial and industrial) classes. Does this reduce the weights that are appropriate for volume and peak demand variables in the output index for productivity research intended to establish a price cap index productivity factor?

OEB staff B8-26
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pg 5 – PSE TFP study
Figure 2 shows the estimated annual TFP for the Ontario electricity distribution sector as estimated by PSE. Following the chart, PSE states:

> *"The Ontario industry had four consecutive years of TFP growth from 2002 to 2006. Then mixed results from 2007 to 2010. Since 2010, Ontario has experienced five consecutive years of TFP declines. Some of this drop is possibly due to the economic downturn. Other factors, such as aging infrastructure, increasing unmeasured outputs (e.g. environmental, regulatory, safety, customer service), and the general slowing of output growth, are also possibilities."*

While the issue of aging infrastructure is true in some instances, the Ontario electricity distribution sector has had significant capital investments in new technologies such as smart meters and associated communications technologies. Following restructuring, market opening and the legislated rate freeze, there have been major capital programs undertaken by most distributors from 2008 onwards. While there was the economic downturn in late 2008, the recovery from 2009 onwards has been positive and prolonged, even if growth is gradual. However, many distributors have seen growth in customers or connections, even if average energy consumption and demand per customer/connection is trending downwards, due, in part, to changes in the economy, technology and conservation initiatives.

As PSE has done work in the Ontario electricity sector, both for the OEB and for electricity distributors, it would have a comprehensive understanding of the Ontario electricity sector.

a) Can PSE provide a more detailed and fuller explanation for what factors are driving the negative TFP for the Ontario electricity distribution sector after 2009?

b) Could these results be also reflective of data and data adjustments that PSE made, particularly subsequent to 2012 (i.e., PEG's TFP study as done for EB-2010-0379), in conducting its analysis?

OEB staff B8-27
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pp 12-13 – Negative TFP Growth Productivity Report

PSE states that:

"While declining efficiency is certainly one possibility for observing negative TFP trends, there are a number of other possibilities. Given the presence of incentive regulation, it seems unlikely that efficiency is declining across the entire industry. Other systemic possibilities include:

1. *The increasing of "outputs" that are not being measured within the TFP calculation. PSE attempts to partially solve this issue with the performance adjustments found in this study. As applied to Hydro One, we see that the long-term trend for Hydro One goes from slightly negative to slightly positive after incorporating and adjusting for the valued services of reliability and employee safety. While PSE's performance adjustments (discussed in the following section) attempt to quantify these performance outputs, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include customer service activities, meeting increased regulatory requirements, providing enhanced environmental stewardship, and increasing other aspects of power quality.*

2. *External circumstances can change over time. One of these circumstances often found in modern western economies is slower growth. Output growth has slowed due to more energy efficient appliances and machinery and conservation programs. This has slowed both the total amount of energy delivered (in kWh) and peak demands (in kW). The growth in customers, especially in more rural areas, has also slowed. Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP from historical norms.*

3. *A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during that time, utilities needed to heavily invest in capital infrastructure to meet the higher number of customers and peak demands (unlike today they were able to fund much of this investment through increasing billing determinants rather than higher prices). At a number of utilities throughout North America a high proportion of capital infrastructure is now past its useful life and is in need of replacement. However, capital expenditures may need to increase to replace this capital. Additionally, maintenance costs will also tend to increase as the grid becomes older. The capital replacement expenditures and increasing maintenance costs will tend to cause a decline in TFP."*

a) Please discuss the extent to which the following additional circumstances may have driven the productivity growth of Hydro One and other Ontario electricity distributors to be negative during this sample period:

- Catching up on deferrable capital and OM&A expenditures following the end of the rate freeze on Ontario power distributor rates in late 2004.
- Conversion of most Ontario power distributors during the 2012-15 period from CGAAP to alternative accounting methodologies like IFRS.

b) To the extent that these two circumstances have influenced TFP growth, is the full 2003-2015 Ontario sample a good one for establishing a productivity factor for Ontario power distributors?

OEB staff B8-28
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pp 12-13, 23 – PSE TFP study
In section 3.2, PSE provides its discussion on the interpretation of negative TFP results. Under bullet 2, it states:

> *"External circumstances can change over time. One of these circumstances often found in modern western economies is slower growth. Output growth has slowed due to more energy efficient appliances and machinery and conservation programs. This has slowed both the total amount of energy delivered (in kWh) and peak demands (in kW). The growth in customers, especially in more rural areas, has also slowed. Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP from historical norms."*

On page 23, PSE states that it used an economic depreciation rate (d_t) of 4.59% as did PEG in the EB-2010-0379 study.

OEB staff acknowledges that energy consumption and peak demand is declining, generally and for many distributors, particularly when customer growth is also considered. This does result in under-utilization of existing assets that are largely "sunk" once installed. This would result in lower productivity, all else being equal, in the short term. However, certain assets, such as transformer stations, may experience lower wear and tear and it may take longer for demand to reach designed capacity, both of which can extend the lives of such assets over time, and delaying the time for capital expenditures to replace or reinforce these assets.

As a result of an asset life study by Kinectrics Inc. commissioned by the OEB (EB-2010-0178, *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. (Kinectrics Report) for distributors sponsored by the Board dated July 8, 2010, or of studies conducted by or on behalf of individual electricity distributors, many distribution asset lives have changed. Expected useful lives of many core distribution assets have increased. There were also changes in capitalization policies, and nearly all Ontario electricity distributors have changed from CGAAP to IFRS, US GAAP or ASPE. Most of these changes would have occurred in 2013 or 2015, with few electricity distributors effecting changes in 2012 (i.e., at the end of the time period for PEG's analysis in EB-2010-0379).

> How has PSE taken into account these accounting policy changes which also, with respect to depreciation rates/expected useful lives, have real investment and operational impacts on distributors' physical networks? PSE's response should address both capital (i.e. capital stock formation and the associated index) and OM&A expenses and the associated indices.

OEB staff B8-29
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pg 17 – Output Index Form

PSE states on page 17 of its Productivity Report that:

> *"For Hydro One and the industry TFP calculations, the output quantity index and input quantity index are constructed using the Törnqvist indexing method."*

Please confirm that the output quantity indexes used by PSE have fixed weights based on econometric cost elasticity estimates and therefore do not have a Törnqvist form.

OEB staff B8-30
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1 pg 22 – Geometric Decay
PSE states on page 22 of its Productivity Report that:

> *"PSE's measure of capital quantity is based on the perpetual inventory capital method. This approach has a solid basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research. [footnote omitted] The approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry."*

a) Does PSE believe that a geometric decay specification for capital cost like that which PSE has chosen to measure the productivity trend of Hydro One is the best for measuring a power distributor's cost efficiency?

b) Does PSE believe that a geometric decay specification for capital cost like that which you have chosen to measure the productivity of Ontario's power distribution industry is the best for studies intended to establish productivity factors for power distributors in IRM plans? Please explain.

OEB staff B8-31
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pg 35 – Hydro One's Productivity Trend

PSE presents the trend in its “unadjusted” total factor productivity (“TFP”) index for HON in Table 16. Hydro One’s O&M input quantity trend is detailed in Table 6.

a) Why did Hydro One’s TFP growth decline markedly in 2006 and 2007? In particular, why did Hydro One's operation, maintenance, and administration ("OM&A") input quantity growth surge following a downward trend 2003-2005?

b) Please extend your productivity calculations to include the 2017-22 period. What rate of productivity growth is implicit in Hydro One's proposed revenue requirements? This analysis should also reflect the updated evidence filed by Hydro One on December 21, 2017.

OEB staff B8-32
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pp 35-36 - Negative Productivity Growth

At this reference, PSE states (Productivity Report) that:

> *“… negative TFP does not necessarily imply worsening efficiency. It simply means that measured input quantity growth is outpacing measured output quantity growth. Possibilities for causes, other than worsening efficiency, include: the economic downturn, slowing output growth even absent the downturn, aging infrastructure requiring large capital replacement and increased maintenance costs, and an increase in unmeasured outputs (e.g., safety, reliability, customer service, regulatory, public safety, and environmental concerns).”*

a) What information is available on the age of Hydro One's distribution assets?

b) What evidence is there that the negative productivity growth of Hydro One has been caused by "aging infrastructure requiring large capital replacement"?

OEB staff B8-33
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pg 41 – Ontario Power Distribution Industry Productivity Trends

PSE presents information on the TFP growth of Ontario's power distribution industry in Table 20.

a) Please expand this table (or prepare additional tables) to present analogous annual results on the following related variables:

- Output quantity subindexes (e.g. kWh delivered, maximum peak demand, and the number of customers served)
- Input quantity subindexes [e.g. capital, labor, materials, and OM&A inputs].
- Partial factor productivity ("PFP") of capital inputs
- PFP of O&M inputs

b) Please add annual growth rates to the expanded table(s).

c) What do these expanded results tell us about the drivers of the purported negative industry productivity growth?

d) Please make sure that the working papers include productivity calculations for each Ontario LDC used in the study and prepare a table that reports trends for each distributor for the ten-year period 2002-2012 and the additional three years 2013-2015 (i.e. three growth rates).

OEB staff B8-34
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 11 - Inflation Forecasts

PSE states:

> *"For the years 2017-2022, projected values were used for Hydro One's variables."*
>
> **Input prices** are calculated using the same procedures as the historical data but with inflation projections. Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour component is set to increase by 1.57% per year. The labour component is set to increase by 2.56% per year. These are the default values used in the OEB total cost benchmarking model projections worksheet. The capital category is set to increase at the same rate as the labour component at 2.56% per year.

a) Was the *construction cost index* or the *capital price* escalated by 2.56%? If the former, what assumption was made about the rate of return on capital?

b) In either event, what is the rationale for using 2.56% as the escalator? Is this consistent with PEG's benchmarking work for the OEB?

OEB staff B8-35
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 17 – Model Estimation Procedure

PSE states on p. 17 that:

> *"The model is estimated using generalized least squares (GLS) in order to correct for*

cross-sectional heteroskedasticity. The parameter estimates that result from this procedure are both consistent and efficient."

a) Why did the estimation procedure not correct for autocorrelation as well as heteroskedasticity?

b) Were Hydro One data used to estimate the model used to benchmark Hydro One?

OEB staff B8-36
Ref: Exhibit ATab5/Schedule 1/pp 50-51 – Regulatory Return on Equity

What is Hydro One Distribution's achieved Return on Equity on a regulated basis for 2016? Please provide a synopsis for the factors influencing this result.

OEB staff B8-37
Ref: Exhibit B1-1-1/DSP Section 1.5/Tables 17, 18 and 19
Productivity Savings - Operations

Table 18 shows the savings forecasted by Hydro One for Cable Locates, and Table 19 shows the savings forecasted for Vegetation Management. These are programs under Operations, for which the forecasted savings are shown in Table 17. OEB staff has prepared the following table from the data in Tables 17, 18, and 19:

Forecasted Operations Savings by Program
Exhibit B1-1-1/DSP Section 1.5/Tables 17, 18, 19

$M

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Cable Locates (Table 18)	7.8	7.6	7.9	8.1	8.2	39.6
Forestry (Table 19)	10	12.9	13.8	14.9	17.4	69
Sub-total	17.8	20.5	21.7	23	25.6	108.6
Total Operations (Table 17)	20	23.1	24.1	25.4	28	120.6
Difference = "Other" Operations Savings	2.2	2.6	2.4	2.4	2.4	12

Savings from Operations programs and projects other than Cable Locates and Forestry (Vegetation Management) average about $2.4M per year.

a) Please describe briefly what other operational savings would make up this $2.4M per year.

b) In light of the updated evidence filed by Hydro One on December 21, 2017, please update this table if necessary, or confirm that no update is required.

OEB staff B8-38
Ref: Exhibit B1-1-1/DSP Section 1.5/Section 1.5.1.3/Table 20
Productivity Savings - Procurement

In section 1.5.1.3, Hydro One describes the forecasted savings by year with respect to the Procurement program. Table 20 provides a detailed breakdown of forecasted savings. Hydro One states on page 9 of this exhibit:

> *"Table 20 lists spending categories and the forecast procurement savings that have been embedded in the business plan over the 2018-2022 planning period."*

How have these savings been reflected in the revenue requirement, given Hydro One's proposed custom IR proposal? In other words, how are the benefits of these savings shared with Hydro One's ratepayers?

Issue 9. Are the values for the proposed custom capital factor appropriate?

Issue 10. Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

OEB staff B10-39
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1, pp 4, 11-12, 40 - Construction Cost Index

PSE states on pp. 35-36 of its TFP Report that:

> *"In updating the Ontario industry TFP to 2015, PSE was unable to use the Electric Utility Construction Price Index (EUCPI), because it has been suspended after the 2014 data release. We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015. For the 2013, 2014, and 2015 plant additions, we use the capital expenditures found in the OEB Yearbooks. All other procedures remained the same relative to EB-2010-0379. For more information on the methodology, procedures, and 2002 to 2012 results please see the November 2013 report by PEG (Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board)."*

a) If PSE believes that the capital quantity growth of HON is more accurately measured using an alternative construction cost index, does it not also believe that the capital quantity growth of *all* Ontario distributors is more accurately measured using this alternative index? Please explain.

b) PSE criticizes the EUCPI for including financing costs. Since financing costs declined during the sample period, did this feature of the EUCPI tend to *under*state growth in construction costs and *over*state growth in the quantity of plant additions? Please fully explain the response.

c) In footnote 3 at the bottom of page 4, PSE notes: “The first is using a different construction cost index in 2015. This is because the index used by PEG (the EUCPI) was suspended after its 2014 data release, making 2015 unavailable. For the years 2013 and 2014 we used the EUCPI.” On page 12, PSE states: “We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015.”

i. Please provide the data used for the extension of the series.

ii. On what basis did PSE conclude that this would be a reasonable alternative to the EUCPI’s publication suspension after 2014? Please recalculate the expanded Table 20 using PSE's alternative construction cost index.

OEB staff B10-40
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 4 – Sample
PSE states on page 4 of its Benchmarking Report that:

“In an effort to produce a dataset that can adequately capture Hydro One’s large size and rural characteristics, PSE used a sample consisting of 380 U.S. distributors."

a) Please provide a list of the U.S. utilities in the sample data base, by each of the two groups: (1) U.S. IOUs serving more than 10,000 customers; and (2) RECs serving more than 10,000 customers.

b) Utilities serving a large region with numerous customers typically also serve major metropolitan areas. Rural utilities typically serve far fewer customers and smaller urbanized areas. Please confirm that few, if any, utilities in the U.S. sample satisfy <u>both</u> PSE's large size and rural service territory criteria.

c) In light of the answer to b), why were no Ontario LDCs included in the study?

d) Does Form 7, which provided most operating data for the regional electric cooperatives ("RECs") in the sample, have a uniform system of accounts that is analogous to that which has long been available for FERC Form 1?

e) What precautions were taken concerning mergers of RECs or transfers of assets between the transmission and distribution accounts?

f) Where did PSE obtain its Form-7 data on the operations of RECs for 2012-2015 if “Publicly available Form-7 data” ended in 2011?

g) Please test the robustness of your methodology by reporting econometric and benchmarking results from a model that excludes observations relying on RUS-7.

OEB staff B10-41
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 12 - Cost Calculations
PSE states on page 12 of its Benchmarking Report that:

> *"We used Hydro One's distribution net plant in 2002. For the rest of the sample we calculated each utility's total net electric plant and then allocated the distribution portion by the percentage of gross distribution plant in total gross electric plant in 2002."*

a) Is the cost of general plant excluded from the study for any of the sampled utilities? If so, why? If so, please provide the data required to calculate a capital quantity index for Hydro One's general plant.

b) What precautions were taken concerning U.S. mergers and acquisitions and transfers of plant between transmission and distribution accounts?

c) How did PSE calculate OM&A expenses of Hydro One, U.S. investor-owned utilities ("IOUs"), and rural electric cooperatives ("RECs")?

d) How were administrative and general expenses handled?

e) Where do pension and benefit expenses appear in Form 7? Are these itemized?

OEB staff B10-42
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 7 - Benchmark Year Adjustment
PSE states that:

> *"We use 2002 as the benchmark year in the current study for all utilities".*

a) What is the earliest practicable benchmark year for calculating a capital quantity index for the sampled RECs?

b) What is the earliest practicable benchmark year for the sampled U.S. IOUs?

c) Why was a 2002 benchmark year used for US companies as opposed to the earliest practicable year?

d) Does the use of a 2002 benchmark year when an earlier benchmark year is available reduce the accuracy of estimated capital costs for U.S. utilities?

e) Please test the robustness of the econometric and benchmarking results by re-estimating the model using the earliest practicable benchmark year for each sampled utility.

f) Does Hydro One have available data on plant in service and accumulated depreciation prior to 2002 which might allow the calculation of an earlier benchmark year? If so, please provide.

OEB staff B10-43
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pg 8 - Right-Hand Side Variables
PSE states on page 8 of its Benchmarking Report that the output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Maximum peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

- Regional input prices,
- Percent electric customers (out of total gas and electric customers),
- Forestation of the service territory,
- Square kilometers of territory served per customer,
- Percent of territory designated as “artificial surface,”
- Percent customer service and information expenses in distribution OM&A,
- Extreme weather conditions, and
- A time trend variable.

a) Please explain fully how the peak demand data are defined in all three data sources (i.e. including Ontario). Since the REC demand data are from Form 7, how did PSE deal with the fact that RECs are permitted on that form to file either coincident or non-coincident peak demand data? Which approach was most common? Which RECs changed their approach to reporting demand data during the sample period? What adjustments were made to the raw demand data to create the "maximum peak demand" variables used in the modelling?

b) Please confirm that PSE's labor price indexes for sampled U.S. electric utilities are constructed from BLS salary and wage data. What indexes were used to escalate the U.S. labor price index?

c) Please provide a thorough explanation of PSE's calculation of a labor price index for Hydro One.

d) Please describe how the benchmarking study accounted for differences in company-provided benefits (e.g. health care and pensions) of the U.S. utilities and Hydro One.

e) Ref Page 10: *"…To construct the overall OM&A input price, we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used by PEG in their benchmarking research."*

  i. Please confirm that PEG used these O&M weights to construct an OM&A price index for a cost benchmarking model that was estimated using only *Ontario* data.

  ii. Were the 70/30 weights applied to the sampled US LDCs as well as to Hydro One? If so, why?

  iii. What is a typical share of labor cost in the O&M of US power distributors?

f) Ref Page 5: *"The Ontario component uses the same GDP-PI in each year, but adjusted for the purchasing power parity ("PPP") index."*

  i. Was the PPP adjustment for O&M expenses applied for one year or every year?

  ii. Why is the PPP preferred over the exchange rate in this application?

  iii. Does "GDP-PI" here refer to a US GDP-PI or a Canadian index? Please identify the specific index used.

g) The RS Means indices for which cities were used to levelize the capital price indexes for sampled utilities?

h) Please provide thorough explanations on how the forestation, customer density, and artificial surface variables were constructed. For example, how was the service territory of each company defined?

i) Please prepare a table that compares Hydro One's 2015 values for the cost model's RHS variables to the mean 2015 values for sampled RECs, IOUs, and the full US sample.

j) Please describe any steps to control for the differing amount of sub-transmission work done by sampled US distributors and HON.

k) Please describe the relative merits of attempting to control for the cost of conservation programs as opposed to removing the cost as was done in the Ontario benchmarking work.

l) Please describe any efforts to control for the cost impact of differing amounts of distribution system undergrounding among LDCs.

m) Please describe any efforts to control for differences in the distribution system age of sampled LDCs.

OEB staff B10-44
Ref: Exhibit A/Tab3/Schedule 2/Attachment 1/pg 10 – PSE Total Cost Benchmarking Study

PSE discusses one of the variables in the total cost benchmarking study as Square Kilometers per Customer:

> *"The square kilometers per customer variable is calculated using GIS coordinates of each utility's service area provided to PSE by Platts. The variable equals the total square kilometers of the area of the distributors service territory divided by the number of retail customers served. The customer variable is the same as the output variable that enters the model. We would expect distributors that have to cover more service territory per customer to have higher costs."*

While PSE's expectation is reasonable among firms that are more or less homogeneous in many respects, such as operating in similar geographical regions of the continent, this may not hold across North America. In western Canada and the U.S., state areas are typically larger. There are also more areas in some provinces and states where there may be no electrification (e.g. federal or state/provincial parkland or reserves). Hydro One has some of this in its territory in Ontario (e.g., provincial parks such as Algonquin, Chapleau Crown Game Reserve, etc.). Electrical service may be restricted along transportation corridors (generally roads and highways, railways), along which nearly all residences and businesses will be located. Trivially, there are no costs for unserved territory.

For this reason, customers per kilometer of line (circuit km. of line) is often preferred as a better measure of density than is customers per square kilometer. This may be particularly true given the differences in utilities' service territories across the North American continent.

a) Did PSE consider a measure of density per kilometer of line? If so, why was it rejected? If not, why not?

b) Given observed differences in utilities' service territories across North America, please provide PSE's view on whether this measure would introduce any error or bias in its benchmarking results.

OEB staff B10-45
Ref: Exhibit A/Tab3/Schedule 2/Attachment 2/pp 11, 15 and 16 – PSE Total Cost Benchmarking Study

On pages 15-16, PSE states:

> *"As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory, and is largely outside the control of a firm's managers. On the other hand, the number of employees hired are within management's control, and thus cannot serve as an independent variable."*

One of the "independent" explanatory variables included by PSE in its analysis, is percentage of customer service and information expenses, which is defined on page 11 as:

> *"The percentage of customer service and information expenses is calculated by taking customer service and information expenses and dividing by the total OM&A. Since some U.S. distributors include their conservation demand management expenses within the customer service and information expense category, this variable accounts for those cases. We would expect a higher percentage of customer service and information expenses to be associated with higher total costs."*

a) How many U.S. distributors include conservation demand management costs in the customer service and information expense category?

b) Are all such programs mandated by government or regulatory policy, or how much discretion does the utility have with respect to both the conservation demand management targets, achieving those targets and their control?

c) How are Hydro One's costs for achieving the CDM targets established by the IESO (and formerly the OPA) recorded?

d) This variable is dependent on both the firm's overall level of OM&A expenses, and its CDM-related expenses, which may be partially controllable by the utility's management.

   i. On what basis has PSE concluded that this variable is a suitable proxy for externally-mandated CDM expenses as a cost driver?

   ii. How does this variable, as defined, satisfy the "independence" criterion as documented by PSE on pages 15-16?

OEB staff B10-46
Ref: Exhibit A/Tab3/Schedule 2/pg 4 and Exhibit A-3-2/Attachment 2/pg 20 – Stretch Factor and PSE Total Cost Benchmarking Study

On page 20 of its total cost benchmarking study updated in May 2017, PSE concludes:

> *"The current recommendation of 0.45% differs from the recommendation of 0.60% found in the March 2017 Report. Due to the addition of the 2016 result for Hydro One, the most recent 3-year result is now below the 25.0% stretch factor threshold set by the Board.*
>
> *This 0.45% recommendation comes with the caveat that the most recently available benchmarking scores should be used as the basis for the stretch factor. Therefore,* ***whenever data for additional years becomes available and possible to incorporate into the benchmarking evaluation, then PSE's stretch factor recommendation would be adjusted to reflect the more recent result.***
>
> *For 2017-2022, average projected total cost levels of Hydro One are above benchmark expectations by 22% for the whole period.* ***In the 2018 test year, Hydro One's total costs are 21.4% above benchmark expectations.*** *Based on the 4th Generation IR stretch factor thresholds, Hydro One would be assigned a stretch factor of 0.45% based on these projections."* [Emphasis added]

a) For clarification, is PSE recommending that the 0.45% stretch factor be applicable for the 2018 test year or for the full five-year term of the Hydro One's proposed Custom IR plan?

b) Is PSE suggesting that the total cost benchmarking study be updated annually? If so, would this entail updating data for all utilities (i.e., the 380 U.S. "peer" utilities as well as Hydro One)? If yes, then how much work would this entail, and by what process would the results be reviewed and approved for establishing the stretch factor for adjusting Hydro One's distribution rates for each year from 2019 to 2022?

c) Hydro One has proposed that the 0.45% stretch factor be held constant throughout the five-year term. If PSE is proposing that the stretch factor be updated annually, why has Hydro One made its proposal to hold the stretch factor constant?

OEB staff B10-47
Ref: Exhibit B1-1-1/DSP Section 1.5/pg 2/Table 17- Productivity Savings

Table 17 shows the detailed productivity savings that Hydro One has estimated for the capital and OM&A programs in its application, by year. Hydro One states that these savings are factored into the capital and OM&A plans.

a) Are the savings for Procurement and Administration categorized as capital or OM&A in nature? If mixed please provide a disaggregation.

b) It is easy to see how OM&A productivity savings in 2018 can be factored into the 2018 revenue requirement and hence reflected in 2018 distribution rates to recover that revenue requirement, all else being equal. Similarly, with the forecasted capital budget which is factored into the forecasted rate base for each year, it is easy to see how the capital productivity savings can be factored into each year's revenue requirement. However, Hydro One has proposed that the OM&A component of each year's revenue requirement is adjusted formulaically by inflation-less-productivity for the period 2019-2022.

   Please explain how the expensed productivity savings for 2019-2022 are factored into the revenue requirement derivation so that customers receive the benefits of these savings.

OEB staff B10-48
Ref: Exhibit B1-1-1/DSP Section 1.6 – Benchmarking

On page 1 of this exhibit, Hydro One states:

> *"In the Decision in Hydro One's last Distribution Rate Application for the 2015 to 2019 rates (EB-2013-0416), dated March 12, 2015, the OEB found that the proposed plan showed limited prospects for continuous improvement, lacked externally imposed improvement incentives, included limited cost and productivity benchmarking support, and failed to demonstrate value to customers commensurate with the forecast spending. To address the perceived shortcomings in the application, the OEB directed Hydro One to undertake several studies and submit reports.*
>
> *The undertaking of these studies and reports presented Hydro One with the opportunity to demonstrate continuous improvement by different means: comparison to self; comparison to others; and unit cost trending analysis. This will assist Hydro One align its performance outcomes with those of the RRF.*
>
> *Hydro One also challenged itself, venturing further ahead than just undertaking the studies and reports asked of it by the OEB. Hydro One identified other studies that would help it perform more efficiently, develop a*

> *culture of continuous improvement and stay on the path to excellence in execution."*

As described in the pages following in this exhibit, it appears that IT Budget is the only benchmarking study of an operational nature and filed in the application that Hydro One has done of its own initiative. The total cost benchmarking study conducted by PSE also appears to not have been directed; however, OEB staff sees this as complementary to the TFP analyses also conducted by PSE.

a) Please confirm, correct or clarify OEB staff's understanding of the filed benchmarking studies and whether they were directed or conducted by Hydro One of its own initiative.

b) Are there other areas of its capital and operations programs that Hydro One considered suitable for benchmarking? If so, please provide a list, including why these were not completed or the status of each that is still ongoing, and when Hydro One expects that the study would be completed.

c) Please identify other benchmarking studies that Hydro One participates in and are conducted by other organizations such as the Canadian Electricity Association or the Edison Electrical Institute. Provide copies of any recent studies or, alternatively, a synopsis describing each study and the results. Also, indicate how each study has informed Hydro One with respect to its capital and operational management of its electric distribution business.

OEB staff B10-49
Ref: Exhibit B1-1-1/DSP Section 1.6.3.4 – Benchmarking – IT Budget

Under Recommendation 2, with respect to (IT) Capitalization Policy, Hydro One states that its Finance group is *"reviewing the current capitalization policy of $2M and will be making a decision in the near future on a potential reduction of the minimum threshold"* based on the benchmarking study's analysis that shows the peer group have capitalization thresholds of $250K to $500K.

a) Has any change in IT capitalization policy been reflected in the budget plan or the forecasted revenue requirement for 2018-2022? If so, please explain.

b) Please explain what would be the efficiencies resulting from a change in the capitalization. Further, explain the impacts on Hydro One from a financial and credit metrics impact, on Hydro One's investors, and on Hydro One's ratepayers.

OEB staff B10-50
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1 – Distribution Unit Cost Benchmarking Study: Pole Replacement and Substation Refurbishment/pages 4 and 12 - Credentials and Project Cost

Pursuant to an OEB order to conduct an external unit cost benchmarking study of its distribution pole replacement and station refurbishment programs and an internal unit cost trend analysis, Hydro One commissioned Navigant and First Quartile ("the authors") to perform such a study. The document *Distribution Unit Cost Benchmarking Study* ("Unit Cost Report") provides an overview of their work.

a) Please provide a list of similar projects the authors have done, referencing reports that are in the public domain.

b) Please provide the terms of engagement or other instructions from Hydro One to the authors for conducting the work.

c) Was a more thorough statistical report prepared? If so, please provide it.

OEB staff B51
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1 pp. 1, 4-5 and 20 – Sample

The authors state on page 1 that:

> *"This work leveraged First Quartile Consulting's existing transmission and distribution benchmarking program participants as well as additional companies recruited specifically for this study."*

Further, on pages 4-5:

> *"The goal of the comparison group selection is to find utilities that represent the industry, with both similarities and differences from Hydro One. Similar utilities provide the opportunity for direct comparisons of outcomes (costs, service levels, etc.) while dissimilar utilities offer the opportunity to investigate a broader array of practices that might be beneficial for Hydro One. Companies across North America were identified and evaluated for their usefulness as part of the comparison group. As a result, 29 North American Utilities were approached to participate in the study...*
>
> *A concerted effort was made, as requested by stakeholders, to include more Canadian utilities. However, because there is no requirement for them to participate, and the effort for them to participate is significant, only a few Canadian utilities agreed and provided data for the study. As shown in Figure 5, the utilities in the comparison group are located throughout Canada and the U.S. There are several large companies, some smaller ones, with regulatory circumstances and weather patterns similar and different from Ontario. The net*

result is a reasonably representative and useful comparison group."

The authors also state on page 20 that Hydro One has the *"second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile)."*

a) How many (and specifically which) participants in the study had already participated in a First Quartile or Navigant benchmarking study, and how many (and which) were added specifically for this study?

b) Please identify the companies that were invited but chose not to participate. How many of these non-participants have been in First Quartile or Navigant benchmarking programs?

c) The resulting peer group includes many utilities (e.g. Austin, SCE, Oncor, Centerpoint, Com Ed, PECO, and PEPCO) which serve large urban areas. Several operate in markedly different climates with less extensive forestation. How then is this comparison group "reasonably representative"? Should the "dissimilar utilities" be included in the unit cost calculations? Can you identify a subset of the peers that are *especially* representative?

d) Since the authors use unit cost metrics, there is an automatic (if imperfect) control for differences in the operating scale of sampled utilities. Do you agree that peer group selection should therefore be based chiefly on criteria other than operating scale such as the "demographic scale variables" listed on p. 4? What are the key drivers which should ideally determine peer groups for distribution poles and substations? What is the relative importance of these drivers? Is there any reason why the peer groups for poles and substations should be the same?

e) The sample period for the study was 2012-14. Since HON filed in mid-2017 to set rates for several future years, please explain why data for 2015 and 2016 were not included.

OEB staff B10-52
Ref: Exhibit B-1-1-/DSP Section 1.6/Attachment 1 – Distribution Unit Cost Benchmarking Study: Pole Replacement and Substation Refurbishment/pp 4 &12

On page 4 of this Navigant study, it is identified that collected information included

> *"Number of in-service poles by material type and age profile" and "Planned Service Life for different pole types."*

On page 12, Figures 14 and 15 are labelled as pertaining sole with respect to wood poles.

a) Does the Pole Replacement/Refurbishment Unit Cost Benchmarking study only pertain to wood poles, or to all poles? Are the other figures shown in the study with respect to all poles, or only for wood poles?

b) Some of the utilities identified as being contacted for the pole benchmarking study would appear to operate in more urbanized areas relative to Hydro One. While Hydro One does operate in some urban and suburban areas, primarily service areas of acquired utilities, this is a smaller fraction of its poles and hence pole installation, inspection and refurbishment/replacement costs. In addition to the three Ontario distributors contacted (Veridian Connections Inc., Essex Powerlines, and PowerStream (now part of Alectra)), as identified on the map on page 5, other U.S. utilities such as Austin Energy and CPS Energy may also operate in more densely populated and built-up areas on a percentage basis. They may also rely on poles constructed from other materials. How has Navigant and/or Hydro One taken into account the different operating characteristics, including different pole types, in the analysis and conclusions in this study?

OEB staff B10-53
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 7 - Cost Comparisons
On page 7 of the report, the authors state:

> *"The cost analysis portion of the study looked at pole replacement from several aspects – lifecycle costs per pole across all poles, unit costs per pole worked on in a year, and then costs of individual aspects of the pole program such as inspection costs, replacement costs, and refurbishment costs."*

a) Please provide a detailed explanation of how "life cycle costs per pole" were calculated.

b) How did the authors ensure standardization of the reported cost data? For example, were there differences in overhead, capitalization, and benefit accounting? If so, how were adjustments made?

c) Please confirm that the study did not benchmark the *capital* cost (e.g. depreciation and return on rate base), or the unit *total* cost of poles or substations.

d) How does a focus on cost *per pole* address commission concerns about the number of annual pole replacements?

OEB staff B10-54
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 6 - Input Prices

The authors state on page 6 of their report that:

> *"Because the comparison group includes both U.S. and Canadian utilities, the first normalization step was to convert all cost figures into Canadian currency. All charts and tables showing dollar values are based on Canadian dollars. The conversion rate used for data submitted by U.S. companies was the average currency exchange rate in effect during the year in which the work was performed. The shift in the exchange rate in 2014, the Canadian companies look slightly more cost effective, despite any change in their actions. All values are presented in nominal dollars, and costs were not adjusted for inflation when taking an average or aggregating across multiple years."*

a) Why were exchange rates employed for currency conversion rather than the measures of purchasing power parity used in PSE's benchmarking study for Hydro One?

b) Have the authors used exchange rates in all of their transnational cost benchmarking studies?

c) Several sampled utilities serve large urban areas where high wage rates are common. Did the authors not control for differences in local input prices of sampled utilities, like PSE did in its benchmarking study? If not, why not?

d) Doesn't the lack of control for *inflation* limit the accuracy of the performance *trend* results that the Board requested?

OEB staff B10-55
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 7 - Pole Program Costs

The authors state on page 7 that:

> *"Another way to view pole program costs is through the unit cost of the poles touched (or treated) during an individual year. This is affected by the choices of how many poles to work on during a year, and what is done to those poles. "Poles touched" in this case is those inspected, refurbished, or replaced during the year, so depending on the mix of work done, the costs can vary year to year for an individual company."*

The authors state on page 8 that:

> *"Inspection costs are a function of what is done during the inspection. For example, is it a visual inspection, sound and bore, or other more complex physical inspection. Hydro One performs visual and light physical inspections on a shorter interval than most other companies (three to six years compared to 10 for the*

> *panel). Hydro One is the only company that does not use bore, excavation or ultrasonic methods on a dedicated schedule (seven to 20 years)."*

Please confirm that Figures 8 and 9 do not control for differences in the mix of procedures of the sampled companies.

OEB staff B10-56
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1, p. 15 – Pole Replacement Costs

Please confirm that the pole replacement costs shown in Figures 18 and 19 on page 15 include the costs of the replacement pole as well as the costs of emplacement. Are costs for removal of the replaced poles also included?

OEB staff B10-57
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 17 – Multiple Scale Variables

The authors state on page 17 that:

> *"A limited number of companies completed a full station rebuild in the past three years. The costs associated with these projects were compared on a per-transformer bank basis and a per-MVA basis."*

The authors similarly compute two unit cost metrics for substation-centric refurbishment projects. They state on page 19 that:

> *"Hydro One's projects...fall at different points within the comparative cost spectrum, whether measured on a per-transformer or a per-MVA basis."*

a) What research has been conducted by the authors to ascertain the relative importance of the number of transformers and MVA capacity as drivers of substation cost?

b) How is the OEB to weight multiple unit cost comparisons that use different scales for the two metrics?

OEB staff B10-58
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 17 – Substation Refurbishments

The authors state on page 17 that

> *"Since companies take different approaches to substation refurbishment, it was necessary to group the refurbishment work into several categories – full station rebuild projects, substation-centric projects, and component-based projects."*

a) Please provide a thorough description/explanation of these categories.

b) Does the cost of a full substation rebuild project include the new equipment or just the cost of its installation?

c) Please appraise Hydro One's overall substation refurbishment cost per refurbishment project and its refurbishment cost per transformer bank and substation MVA.

OEB staff B10-59
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 1/p. 20 – Substation Refurbishments

The authors state on page 20 that:

> *"Hydro One's current emphasis on station centric and full station rebuild projects is not unique within the comparison group and is related to several demographic factors that distinguish Hydro One:*
>
> - *Higher than average transformer loadings at non-coincident peak;*
> - *An older age profile for in-service power transformers;*
> - *Highest percentage of single transformer substations; and*
> - *Second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile)."*

Please explain how the third and fourth "demographic" factors on this list affect the approach to refurbishments by any utility.

OEB staff B10-60
Ref: Exhibit B1-1-1/DSP Section 1.6/Appendix 2/CN Utility Consulting Hydro One Vegetation Management Benchmarking Study/pg 14

On page 14, CN Utility Consulting states:

> *"Customer density is important when analyzing the cost to the customer and reliability. In 2011-2015 each Hydro One customer spent on average $99.36 for UVM. Although this is above the average ($35.13 in 2015) for utilities in their peer group, it is important to note some extenuating circumstances that contribute to higher cost for Hydro One customers …"*

Is the $99.36 per customer an annual number or the average cost per customer for the 2011-2015 period?

OEB staff B10-61
Ref: Exhibit B1-1-1/DSP Section 1.6/Attachment 2/CN Utility Consulting Hydro One Vegetation Management Benchmarking Study/p. 48

On page 48, CN Utility Consulting states:

> *"Although Hydro One compares favorably using the metric of outages per kilometre, it will have to make improvements in reliability performance for the foreseeable future. First and foremost, the UVM department should be investigating tree-caused outages. Hydro One* ***is the only utility in the survey where the vegetation management department does not investigate tree-related outages.*** *It is also unknown how many tree-related outages are categorized as unknown or weather-related."* [Emphasis added]

a) Why does Hydro One not investigate and further document tree-related outages?

b) What plans does Hydro One have with respect to CNUC's assessment and recommendations on pages 48-49 of CNUC's study?

OEB staff B10-62
Ref: Exhibit B1-1-1/DSP Section 1.6/pp 11-12 and Exhibit B1-1-1/DSP Section 1.6/Attachment 3/Gartner IT Budget Assessment

Hydro One notes that it undertook this study of its own initiative – i.e., it was to address a directive from the OEB from a prior decision. Table 26 provides a summary of the key findings, while Table 27 (reproduced below), provides a summary of recommendations:

#	**Recommended Actions**
1	Optimize enterprise computing and storage costs and increase server virtualization.
2	Reduce materiality threshold for IT capital expenditure.
3	Review IT organization structure and identify any duplication between roles and responsibilities of retained staff and outsourced service provider.

Hydro One states that more information is provided in section 1.6.4 [sic – 1.6.3.4], but there is little additional information there, and the discussion regarding recommendations 2 and 3 states that work is ongoing.

a) What has Hydro One done or is it doing, and when are decisions and implementation of these expected to occur.

b) How has Hydro One reflected any decisions taken to date regarding the recommendations from the Gartner study? For recommendations 2 and 3, given that their assessments seem to be ongoing, how has Hydro One factored in, or propose to factor in, any cost, cost efficiencies or productivity improvements as a results of decisions taken during the five-year term of the proposed Custom IR plan.

OEB staff B10-63
Ref: Exhibit B1-1-1/DSP Section 2.3/pg 13/Figure 19 – Number of Transformer Replacements

Please provide a variation on Figure 19 showing the number of transformer replacements by year, segregating by Planned versus Unplanned replacements.

Issue 11. Are the results of the studies sufficient to guide Hydro One's plans to achieve the desired outcomes to the benefit of ratepayers?

Issue 12. Do these studies align with each other and with Hydro One's overall custom IR Plan?

Issue 13. Are the annual updates proposed by Hydro One appropriate?

Issue 14. Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

Issue 15. Is the proposed Earnings/Sharing mechanism appropriate?

OEB staff B15-64
Ref: Exhibit A/Tab3/Schedule 2/pg 9 – Earnings Sharing Mechanism
Hydro One documents its proposed Earnings Sharing Mechanism as follows:

"Hydro One proposes to share with customers 50% of any earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One Distribution's next rebasing. The calculation of the actual ROE for a test year will use the Board approved mid-year rate base for that period."

Per the proposal in this application, Hydro One's next rebasing would be for rebased rates effective January 1, 2023. At the time of application, or even of a decision and rate order, audited actuals for 2022 may not be available. How is Hydro One proposing the clear the balance of the proposed ESM deferral account in this situation?

Issue 16. Are the proposed Z-factors and Off-Ramps appropriate?

OEB staff B16-65
Ref: Exhibit A/Tab3/Schedule 2/pg 12 – Off-ramp

Please confirm whether the ROE would be calculated on the regulated Distribution operations of Hydro One, or for Hydro One on a consolidated Distribution and Transmission basis.

C. OUTCOMES, SCORECARD AND INCENTIVES

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

OEB staff C17-66
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.1 (5.2.3 A AND B) METHODS AND MEASURES, Table 8 – Distribution OEB Scorecard, Page 1918 of 2930.

Table 8 – Distribution OEB Scorecard

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

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

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

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

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

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

OEB staff C18-67

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.4 ATTACHMENTS: PERFORMANCE MEASURES AND OUTCOME MEASURES, Attachment 1: Productivity Reporting Governance Document, Page 1964 of 2930.

"*Deliverables and Stakeholders*

Productivity reporting has two primary customers, including the Executive Leadership Team and the OEB. The OEB requires annual reporting to ensure performance levels are being maintained as well as for rate setting purposes during regulatory proceedings. The Executive Leadership Team requires monthly and quarterly reporting in order to successfully manage the business and achieve the business objectives."

Scorecard	Ontario Energy Board	Executive Leadership Team	Operations Managers
Regulatory			
Tx OEB – Tier 1	Annual	Quarterly	Monthly
Dx OEB	Annual	Quarterly	Monthly
Electricity Distributor Scorecard	Annual	Quarterly	Monthly
Compensation			
Team Scorecard	Upon Request	Monthly	Monthly
Operational Reporting			
Tx OEB – Tier 2 & 3	Not Provided	Quarterly	Monthly
Operational Reporting	Not Provided	Not Provided	Monthly

a) Please provide examples of the reporting format that will be used for each of the listed reports.

b) What concrete and measurable metrics will be addressed in each report?

c) Are the metrics being used easily quantifiable and measurable? Please provide examples.

Issue 19. Are the proposals for performance monitoring and reporting adequate and do the outcomes adequately reflect customer expectations?

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

OEB staff C20-68

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.2.1 RELIABILITY RESULTS, Table 10 - Historical SAIDI Summary; Figure 3 - Chart of Historical SAIDI; Table 11 - Historical SAIFI Summary; Figure 4 - Chart of Historical SAIFI, Page 1936 – 1937 of 2930.

Table 10 - Historical SAIDI Summary

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

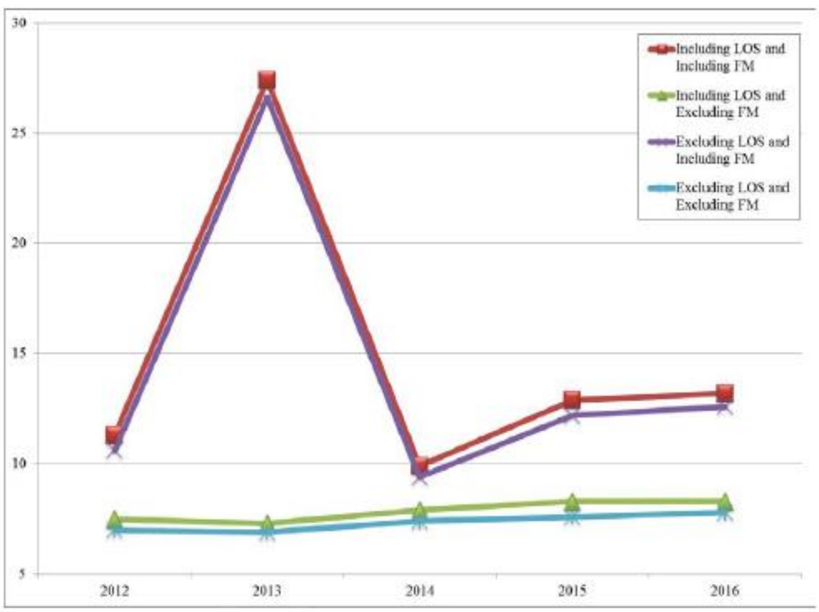


Figure 3 - Chart of Historical SAIDI

Table 11 - Historical SAIFI Summary

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

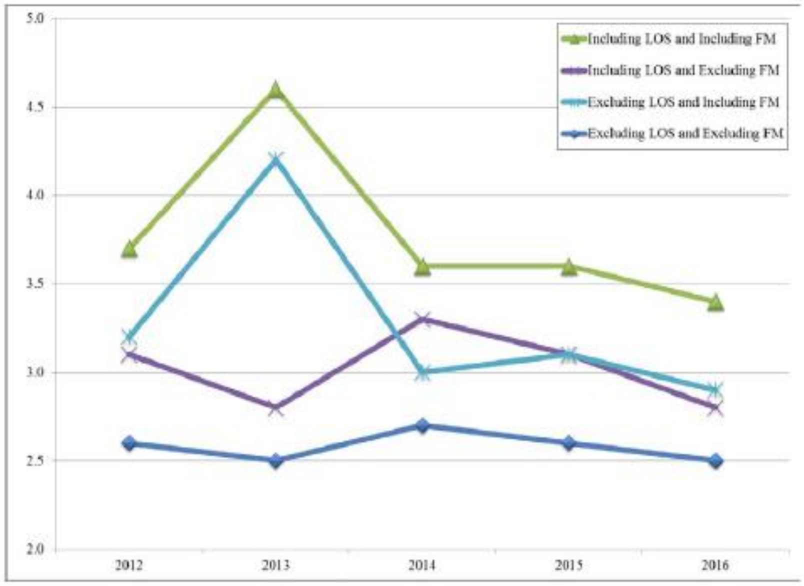


Figure 4 - Chart of Historical SAIFI

a) Please confirm that the correct interpretation of the above figures is that the frequency of outages (ex-LOS and Force Majeure) is staying relatively constant, but average outage durations are becoming longer. If confirmed, please explain why the outage frequency is not increasing, in the context of Hydro One's filed evidence that asset condition is deteriorating, and the vegetation management program is falling behind, which would logically anticipate an increasing frequency of outages.

b) Why is it taking longer on average to restore power after outages? Have Hydro One's investments in remote sectionalizing and smart meter technology measurably reduced average outage durations?

OEB staff C20-69

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.1 (5.2.3 A AND B) METHODS AND MEASURES, Table 8 – Distribution OEB Scorecard, Page 1918 of 2930; and Section 1.4.2.1 RELIABILITY RESULTS, Table 13 - SAIDI by Outage Cause, Page 1939 of 2930.

Table 8 – Distribution OEB Scorecard

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

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

Table 13 - SAIDI by Outage Cause

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

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

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

OEB staff C20-70

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.2.1 RELIABILITY RESULTS, Table 14 - SAIFI by Outage Cause, Page 1940 of 2930.

Table 14 - SAIFI by Outage Cause

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

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

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

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

OEB staff C20-71
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.2.1 RELIABILITY RESULTS, Table 15 – CAIDI* by Outage Cause, Page 1942 of 2930.

Table 15 – CAIDI* by Outage Cause

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

Includes outages due to Loss of Supply and Force Majuere

a) For the Outage Causes listed in Table 15, please indicate which of these causes are within the control of Hydro One, and which are outside of Hydro One's control.

b) Please define what constitutes as Human Element as an outage cause.

c) What action is Hydro One taking to reduce the duration of Tree Contact outages?

d) Table 15 indicates that the duration of outages with Unknown causes has been increasing since 2014. Please identify any actions being taken by Hydro One to reduce the non-identification of outage causes.

   i. Is Hydro One taking any action to reduce the duration of outages with Unknown causes? Please explain.
   ii. Are ongoing Hydro One Smart Grid investments expected to ultimately reduce the number of outages with unknown causes?

Issue 21. Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

OEB staff C21-72
Ref: B1-1-1 DSP Section 1.5, pages 2-3
Hydro One states that the Move to Mobile project will *"result in a 5% increase in field productivity"*, and goes on to identify a reduction of 29 positions.

a) Please provide an update on the status of the implementation, scheduled for April 2017.

b) Please provide a derivation of the capital savings ($10.3 million in 2018, growing to $10.7 million by 2020) from productivity gained through Move to Mobile.

c) Please provide a derivation of the OM&A savings ($2.7 million in 2018, growing to $2.9 million by 2020) from productivity gained through Move to Mobile.

OEB staff C21-73
Ref: B1-1-1 DSP Section 1.5, p 7
Labour Optimization is planned to *"optimize the number of high-skilled regular work staff to the level required to complete core work programs."*

a) How many 'high-skilled' regular work staff does Hydro One employ?
b) How many 'high-skilled' regular work staff does Hydro One expect to employ in 2022?
c) To what extent does Hydro One expect this will impact recovery times from a potential major weather event with significant forestry effort requirements?
d) What steps is Hydro One taking to manage impacts to recovery times?

OEB staff C21-74
Ref: B1-1-1 DSP Section 1.5, pp 8-9
Procurement savings are planned through several measures including "Feedback Rounds – Maximize competitive pressure through multiple feedback rounds on rates, with an opportunity for vendors to improve their proposals" and "Cost Transparency – increase knowledge of bidders' prices and composition to improve Hydro One's ability to challenge and negotiate competitive pricing."

a) Does Hydro One anticipate that the results of these strategies would reveal pricing information of the submitted bids to other vendors? To the public at large?

b) Please explain how the Feedback Rounds and Cost Transparency would work.

c) Please provide a derivation of how much Hydro One expects to save using these measures.

d) Is it reasonable that some vendors, such as competitors and other prospective clients, would hesitate to have their best possible pricing made available. How would Hydro One address this issue?

Issue 22. Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

D. <u>DISTRIBUTION SYSTEM PLAN</u>

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

OEB staff D23-75
Ref: Exhibit B1/Tab1/Schedule 1 – DSP 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."

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?

OEB staff D23-76
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.3: (5.2.2) Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.3 SUMMARY OF CUSTOMER NEEDS AND PREFERENCES, Page 1449 of 2930.

The Ipsos Report showed the following:

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

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".

OEB staff D23-77
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.3: (5.2.2) Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.3 SUMMARY OF CUSTOMER NEEDS AND PREFERENCES, Page 1450 of 2930.

The Ipsos Report showed the following:

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

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.

OEB staff D23-78
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.3: (5.2.2) Coordinated Planning with Third Parties - Customer Engagement, Section 1.3.4 (5.4.1 F) HOW THE PLAN REFLECTS CUSTOMER NEEDS AND PREFERENCES, Page 1451 of 2930.

The evidence indicates:

"2. Customers asked that Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases.

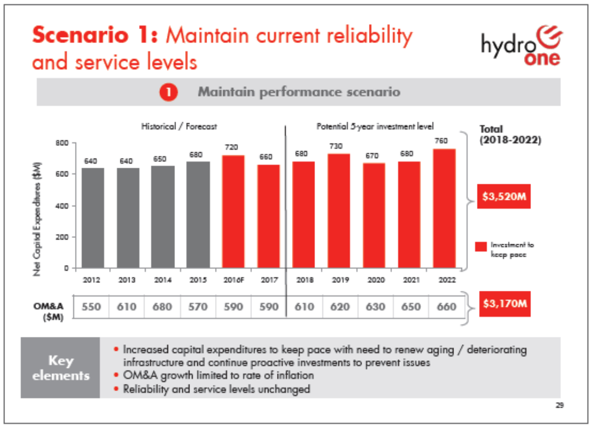
Response: Hydro One has implemented a number of productivity initiatives to reduce unit and operational costs and the associated rate impacts. These productivity initiatives are detailed in Section 1.5."

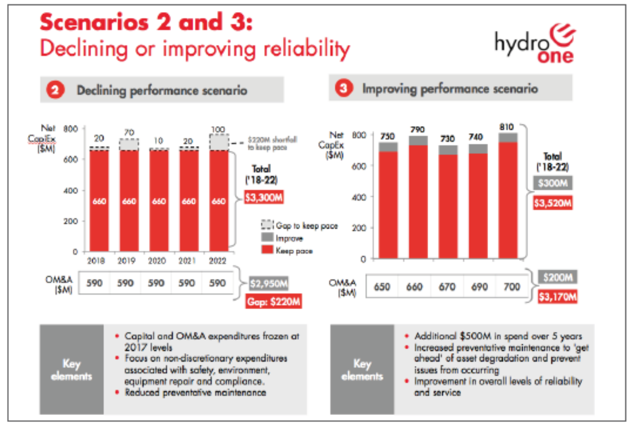
a) Please describe how Hydro One intends to track the results of these productivity initiatives.

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?

OEB staff D23-79

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.3: (5.2.2) Coordinated Planning with Third Parties - Customer Engagement, Workshop Materials: CUSTOMER REACTION TO ILLUSTRATIVE INVESTMENT SCENARIOS, Pages 1696 – 1697 of 2930.





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.

OEB staff D23-80

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.3.1 CUSTOMER FOCUSED PROJECTS, Page 1948 of 2930.

“*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."*

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.

OEB staff D23-81
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.3.1 CUSTOMER FOCUSED PROJECTS, Page 1948 of 2930.

"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."

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?

OEB staff D23-82
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.3.1 CUSTOMER FOCUSED PROJECTS, Page 1948 of 2930.

"*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."

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

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

OEB staff D23-83
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-07 Distribution Lines Trouble Call and Storm Damage Response Program, Page 2618 of 2930.

"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."

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.

OEB staff D23-84
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-03 Reliability Improvements, Page 2675 of 2930.

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."

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.

OEB staff D23-85
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-06 Worst Performing Feeders, Page 2687 of 2930.

"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."

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?

OEB staff D23-86
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-06 Worst Performing Feeders, Page 2691 of 2930.

($ 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.*

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.

OEB staff D23-87
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) 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."

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

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?

OEB staff D24-88

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1. 1: Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) CHANGES TO ASSET MANAGEMENT PROCESS, Page 35 of 2930.

"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."

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.

OEB staff D24-89

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1. 1: Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) CHANGES TO ASSET MANAGEMENT PROCESS, Pages 35 – 36 of 2930.

Ref: Exhibit B1/Tab1/ Schedule 1 – DSP Section 2. 1: Investment Planning Process Section 2.1.4.2 Risk Assessment, Pages 2382 - 2384 of 2930.

"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."

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?

OEB staff D24-90
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.1: Distribution System Plan Overview, Section 1.1.5 (5.2.1 E) CHANGES TO ASSET MANAGEMENT PROCESS, Page 36 of 2930.

“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.”

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.

OEB staff D24-91
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Section 1.4.3.2: Operational Effectiveness Investments, Page 1954 of 2930.

“<u>Distribution Station Component Planned Replacements Program ISD SR 04</u>

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.”

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.

OEB staff D24-92
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Figure 9 - Hydro One's Investment Planning Process, Page 2361 of 2930.

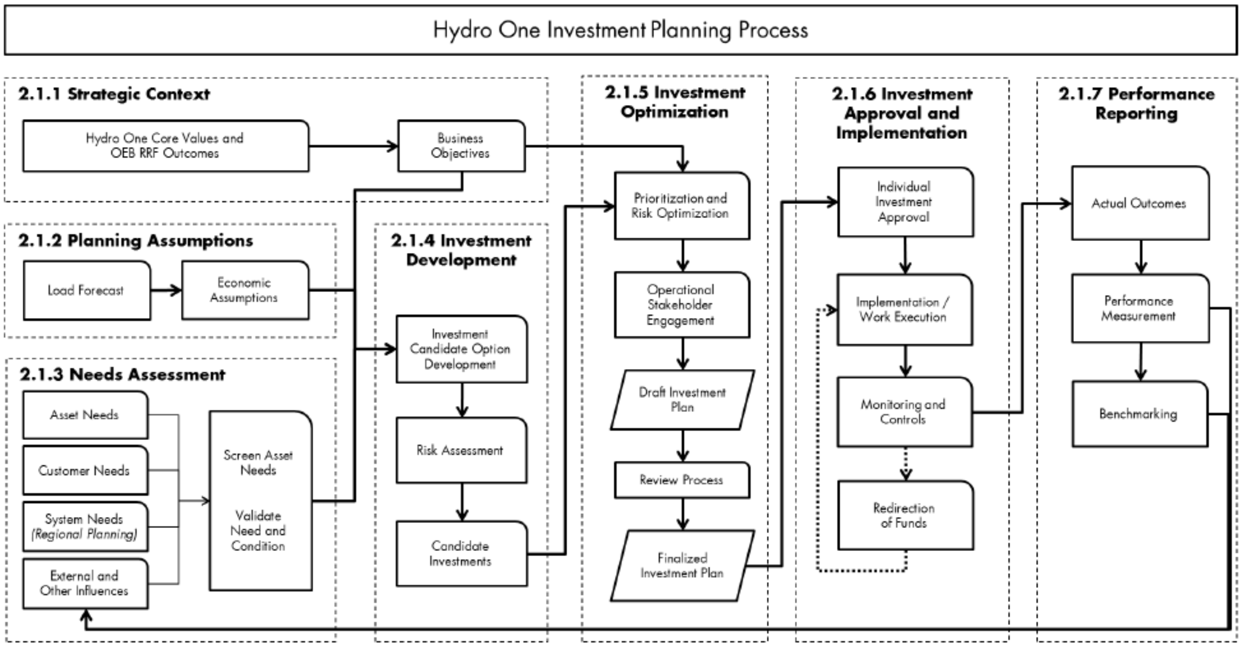


Figure 9 - Hydro One's Investment Planning Process

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.

OEB staff D24-93
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Figure 10 - Asset Need Development Process, Page 2371 of 2930.

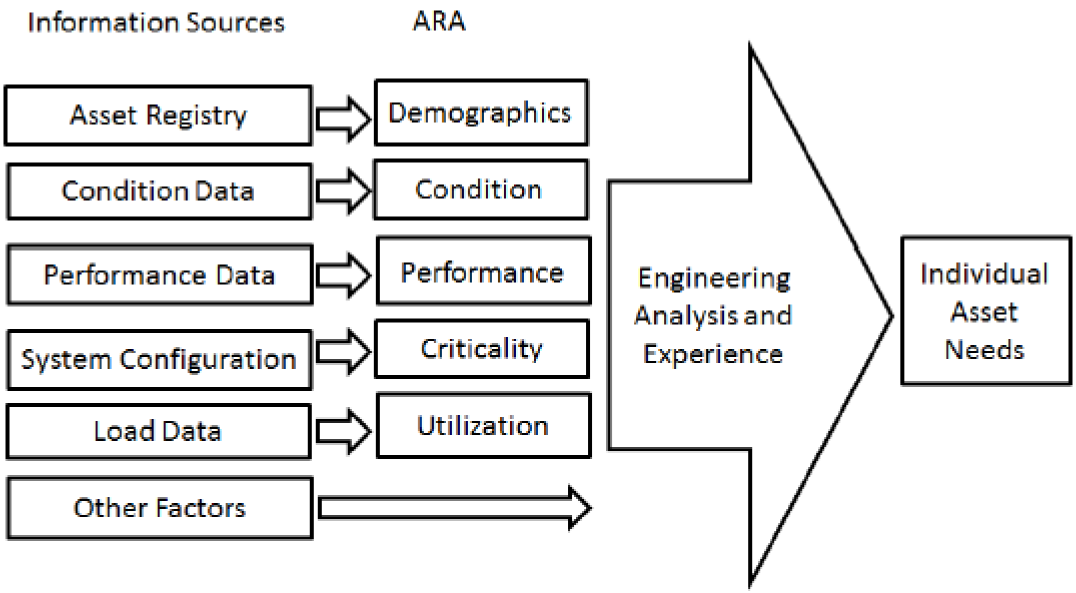


Figure 10 - Asset Need Development Process

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.

OEB staff D24-94
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Page 2371 of 2930.

*"**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."*

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.

OEB staff D24-95
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Page 2371 – 2372 of 2930.

*“**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.”

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.

OEB staff D24-96
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Page 2372 of 2930.

*“**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.

Does Hydro One typically utilize more than one testing approach on a pole before designating it for replacement? Please explain why or why not.

OEB staff D24-97
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Page 2372 of 2930.

> ***"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."*

Please identify the Hydro One asset classes for which replacements are driven primarily or substantially by asset performance risk. Please provide quantified details.

OEB staff D24-98
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.3.1 ASSET NEEDS, Page 2373 of 2930.

> ***"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."*

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?

OEB staff D24-99
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.4.1 INVESTMENT CANDIDATE OPTION DEVELOPMENT, Page 2378 of 2930.

> ***"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."

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.

OEB staff D24-100
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.4.2 RISK ASSESSMENT, Page 2383 of 2930.

"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."

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.

OEB staff D24-101
Ref: Exhibit B1/ Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section 2.1.4.3 CANDIDATE INVESTMENTS, Page 2384 of 2930.

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 of 2930.

“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.”

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.

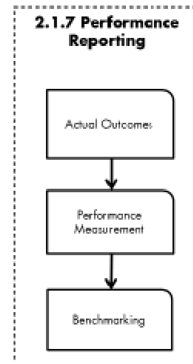
   i. Are these considerations not taken into account by the Asset Investment Planning tool? If not, why not?

   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.

OEB staff D24-102
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.1: (5.3.1) Investment Planning Process, Section (5.3.1 B) PERFORMANCE REPORTING, and Section 2.1.7.1 ACTUAL OUTCOMES, Page 2391 of 2930.

"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."

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?

OEB staff D24-103
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.2: (5.3.2) Overview of Assets Managed, Section 2.2.2.1 DISTRIBUTION STATIONS, Page 2400 of 2930.

"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."

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.

OEB staff D24-104
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1 STATION TRANSFORMERS AND REGULATORS, Page 2412 of 2930.

"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."*

How is the timing for thermal inspections chosen? Is equipment heating correlated with daily and seasonal loading patterns?

OEB staff D24-105
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (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, Page 2418 of 2930.

"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."

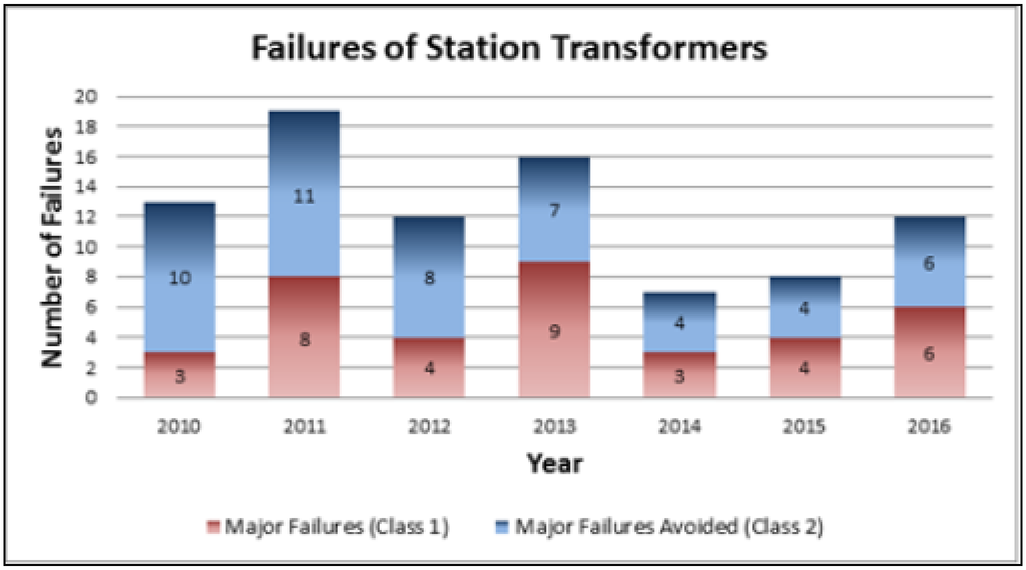


Figure 18 - Failures of Station Transformers

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?

OEB staff D24-106
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (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, Page 2419 of 2930.

"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."

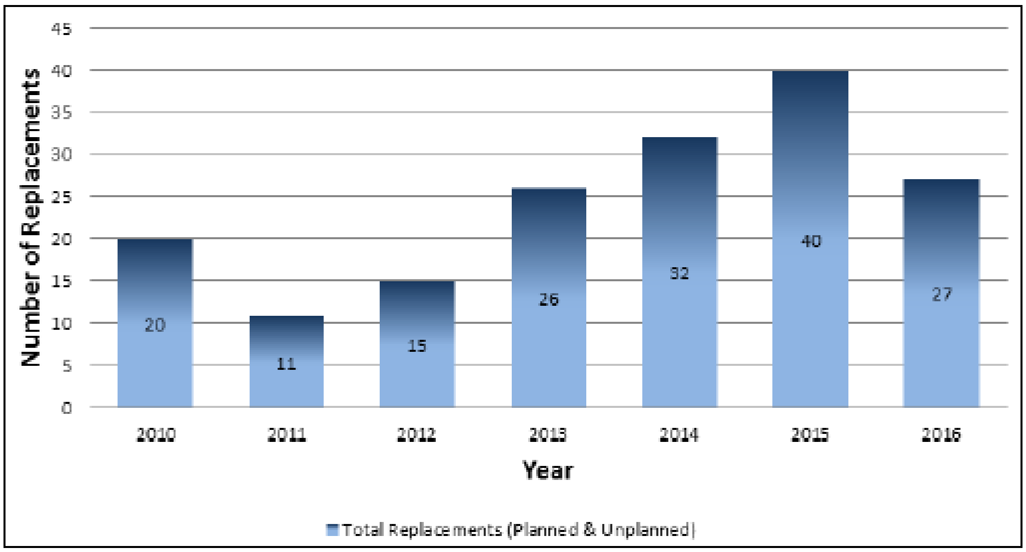


Figure 19 - Number of Transformer Replacements

Please describe the reason for the decrease in number of replacements during 2016.

OEB staff D24-107
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (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, Page 2419 – 2420 of 2930.

"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."

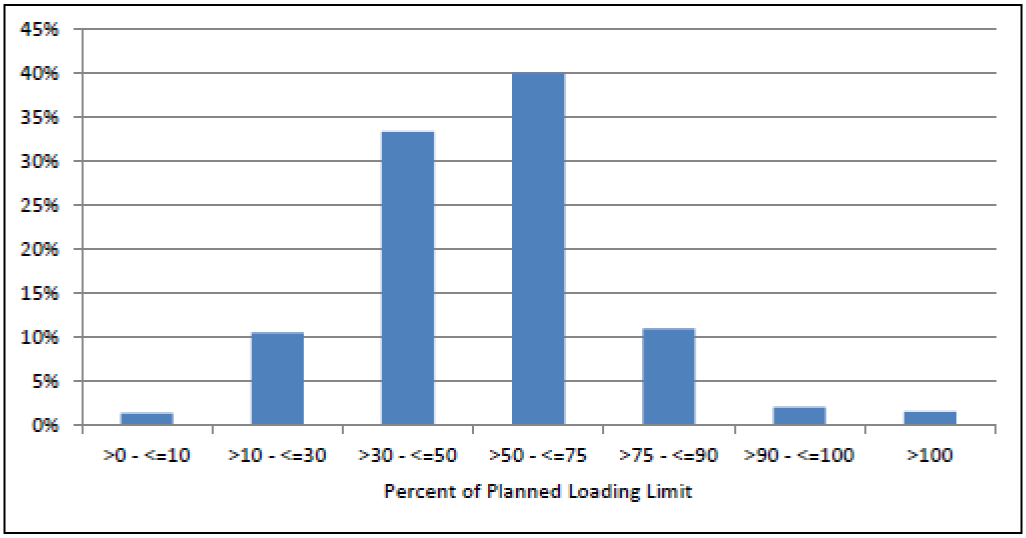


Figure 20 - Station Loading as a Percentage of Total Fleet

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?

OEB staff D24-108

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.1.1: STATION TRANSFORMERS AND REGULATORS, Page 2420 of 2930.

"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."

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).

OEB staff D24-109

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.4.1 MOBILE UNIT SUBSTATIONS, Table 42 – MUS Defects, Page 2432 – 2433 of 2930.

"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**

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?

OEB staff D24-110
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.3: (5.3.3) Asset Component Information and Life Cycle Strategies, Section 2.3.2.1 POLES, Page 2444 of 2930.

*"**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."

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?

OEB staff D24-111
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.4: (5.3.3 B) How the Plan Reflects Investment Planning and Asset Management, Page 2497 – 2498 of 2930.

"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."

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.

OEB staff D24-112
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.4: (5.3.3 B) How the Plan Reflects Investment Planning and Asset Management, Page 2499 of 2930.

"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%."*

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?

OEB staff D24-113
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-08 Distribution Lines PCB Equipment Replacement Program, Page 2622 of 2930.

"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."

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.

OEB staff D24-114
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-10 Distribution Lines Planned Component Replacement Program, Page 2632 - 2634 of 2930.

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.*

Please explain for 2018 why the capital investment is significantly higher for the same number of component replacement units.

OEB staff D24-115
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-12 Distribution Lines Sustainment Initiatives, Page 2638 of 2930.
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."

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.

OEB staff D24-116
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-13 Life Cycle Optimization & Operational Efficiency Projects, Page 2645 of 2930.

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."

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.

OEB staff D24-117

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-18 Integrated System Operating Centre, Page 2780 of 2930.

"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."

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.

OEB staff D24-118

Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 9)

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.4: (5.2.3) Performance Measurement and Outcome Measures, Table 8 – Distribution OEB Scorecard, Page 1918 of 2930.

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 of 2930.

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.

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.

OEB staff D24-119
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec.11)
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-35 Asset Analytics Risk Factor, Pages 2881 - 2885 of 2930.

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."

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.

OEB staff D24-120
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 12)
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 2.2: (5.3.2) Overview of Assets Managed, Page 2394 of 2930.

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"*

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.

OEB staff D24-121
Ref: 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."*

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?

Issue 25. Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

OEB staff D25-122
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.1: 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."

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?

OEB staff D25-123

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.5: (5.2.3) Productivity and Continuous Improvement, Section 1.5.1 PRODUCTIVITY SAVINGS IN THE PLAN, Table 17 – Detailed Productivity Savings Forecast, Page 1966 – 1967 of 2930.

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**

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?

OEB staff D25-124

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.2.3 VEGETATION MANAGEMENT PROGRAM STUDY, Page 1985 of 2930.

"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."

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.

OEB staff D25-125

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.3.2: DISTRIBUTION STATION REFURBISHMENT PROGRAM STUDY, Page 1994 of 2930.

"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."

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?

OEB staff D25-126

Ref: Exhibit B1/Tab1/Schedule 1 – 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, Page 2004 of 2930.

"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.

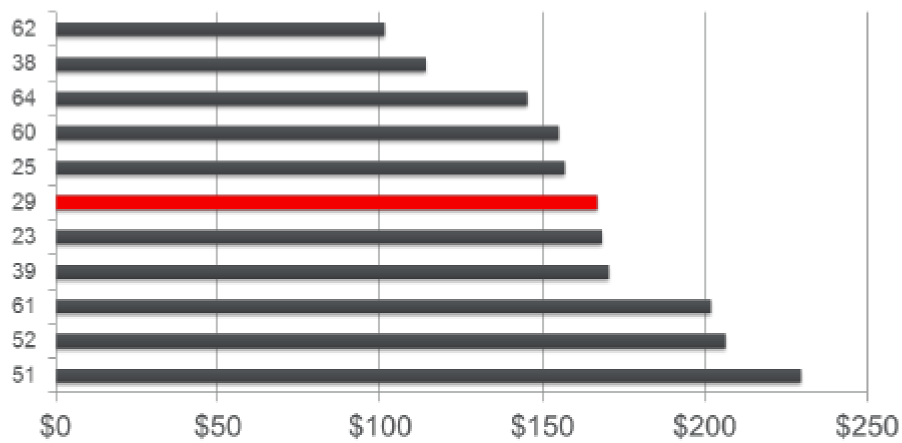
5. *Consider implementing a formal data governance process for equipment performance and maintenance data, and incorporating that information into the asset condition scoring and project planning process.*
6. *Enhance cost and work completion reporting for individual projects, and implement a formal 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."*

Has Hydro One taken action to address these recommendations? Please provide details.

OEB staff D25-127

Ref: Exhibit B1/Tab1/Schedule 1 – 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, Figure 7 – Actual Annualized Life Cycle Costs per Pole per Year, Page 2011 of 2930.

Figure 7. Actual Annualized Life Cycle Costs per Pole per Year



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?

OEB staff D25-128

Ref: Exhibit B1/Tab1/Schedule 1 – 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, Page 2030 of 2930.

"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."

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?

OEB staff D25-129

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2041 of 2930.

"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)"

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.

OEB staff D25-130

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2042 – 2043 of 2930.

"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."

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.

OEB staff D25-131

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2044 of 2930.

"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)."

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.

OEB staff D25-132

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2045 of 2930.

"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)"

How does Hydro One perform in cost efficiency versus hour-efficiency? Please provide a detailed explanation of the discrepancy.

OEB staff D25-133

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2045 of 2930.

"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)"

Why is under-resourcing evaluated in the study as "performed better"?

OEB staff D25-134
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Section 1.6.4 ATTACHMENTS: BENCHMARKING STUDIES, Attachment 2: Hydro One Vegetation Management Study 2016, Page 2046 of 2930.

"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."*

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.

OEB staff D25-135
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Page 2

"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."

Please provide a citation for the referenced OEB report.

OEB staff D25-136
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Page 2

"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."

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.

OEB staff D25-137
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Sect. 1.3 Reliability Results, Pg 3

- *"Off-ROW tree and branch failures cause approx. 90% of all outages"*

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?

OEB staff D25-138
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Sect. 1.4 Forecast Workload and Cost, Page 3

"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."

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.

OEB staff D25-139
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Sect. 1.6 Key Findings, Page 4

*"**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."*

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.

OEB staff D25-140

Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Important Safety Observation, Page 4

"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."

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?

OEB staff D25-141

Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Outage Rates over Time, Page 10

"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."

If Hydro One implements the proposed forestry strategy, is it anticipated to measurably improve performance during severe weather events? Please explain in detail.

OEB staff D25-142

Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Page 12

"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."

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?

OEB staff D25-143
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule1/Attachment 2 – Hydro One – Forestry Survey Assessment, Page 13

"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."

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?

OEB staff D25-144
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule 1/Attachment 2 – Hydro One – Forestry Survey Assessment, Page 13

"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."

Please estimate the second cycle costs, broken down by the same categories shown in Table 6 on pg. 13.

OEB staff D25-145
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.6: (5.4.4) Capital Expenditure Summary, Section 3.6.3 (5.4.4) IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING, Page 2554 of 2930.

"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)."

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.

OEB staff D25-146
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.6: (5.4.4) Capital Expenditure Summary Section 3.6.3 (5.4.4) IMPACT OF CAPITAL INVESTMENT ON OPERATIONS, MAINTENANCE AND ADMINISTRATION SPENDING, Page 2554 of 2930.

"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)."

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?

OEB staff D25-147
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SA-03 Meter Infrastructure Expansion Program, Page 2575 of 2930.

*"**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."

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?

OEB staff D25-148
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-07 Corporate Performance Reporting, Page 2728 of 2930.

"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).”

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.

OEB staff D25-149
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-08 PCMIS Modernization and Optimization, Page 2733 of 2930.

“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.”

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.

OEB staff D25-150
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-10 Work Management & Mobility, Page 2741 of 2930.

“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.”

Please explain in detail how the projected productivity gain was calculated, and explain how the actual results will be reliably monitored and reported.

OEB staff D25-151
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-10 Work Management & Mobility, Page 2743 of 2930.

"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."

Please provide a list of the expected qualitative benefits, including concrete examples of each.

OEB staff D25-152
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-14 Warehouse Scanning Device Replacement, Page 2763 of 2930.

*"**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.

OEB staff D25-153
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: GP-17 S4 HANA for Finance, Page 2775 of 2930.

*"**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.

OEB staff D25-154
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 10)
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.6: (5.2.3) Benchmarking, Vegetation Management Program Study, Pages 1994 - 1997 of 2930.

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.

OEB staff D25-155
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 14)

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.

OEB staff D25-156
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 15)

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-03 Station Spare Transformer Purchases Program, Page 2546 - 2550 of 2930.

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.

OEB staff D25-157
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 16)
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-03 Reliability Improvements, Page 2624 - 2628 of 2930.

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?

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

OEB staff D26-158

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SA-02 Metering Infrastructure Sustainment Program, Page 2573 of 2930.

*"**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.

OEB staff D26-159
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-06 Distribution Station Refurbishment, Page 2611 and 2617 of 2930.
Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –S-07 Station Refurbishment

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.

OEB staff D26-160
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-01 Remote Disconnection/Reconnection Program, Page 2658 of 2930.

"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?

OEB staff D26-161
Ref: Office of Auditor General of Ontario – Annual Report 2015 (Rec. 13)

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.

Issue 27. Has the distribution System Plan adequately addressed government mandated obligations over the planning period?

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

OEB staff D28-162
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.2: (5.2.2) Coordinated Planning with Third Parties - Regional Planning, Section 1.2.3 STATUS OF REGIONAL PLANNING ACTIVITIES, Page 48 of 2930.

"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?

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

OEB staff D29-163
Ref: Evidence Update, 2017-12-21, Exhibit Q/Tab1/Schedule 1/Attachment 1 - Page 12 of 24, Budget Breakdown by OEB RRF

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.

OEB staff D29-164
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.1: Distribution System Plan Overview, Section 1.1 (5.2.1) DISTRIBUTION SYSTEM PLAN OVERVIEW, Page 17 – 19 of 2930.

"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 (ie. The total reliability improvement is the summation of each expected reliability improvement for each project within the Plan)

OEB staff D29-165

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.2: (5.4.1 B) Capital Expenditure Forecast, Table 54 – Historical Bridge Year Capital Expenditure Summary, Page 2509 of 2930.

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)?

OEB staff D29-166
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.2: (5.4.1 B) Capital Expenditure Forecast, Table 55 – Historical and Bridge Year Capital Expenditure Breakdown by SDOC, Page 2512 of 2930.

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)?

OEB staff D29-167
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.2: Capital Expenditure Forecast, Table 57 – Forecast Test Years Capital Expenditure Breakdown by SDOC, Page 2515 – 2516 of 2930.

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.

OEB staff D29-168
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.7: (5.4.5.1) List of Material Capital Investments Proposed, Pages 2555 - 2560 of 2930.
Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 2 - List of Capital Expenditure Programs/Projects in excess of $1M, Pages 1 - 5 of 5.

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.

OEB staff D29-169
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SA-04 New Load Connections, Upgrades, Cancellations and Metering, Page 2578 of 2930.

*"**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?

OEB staff D29-170
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-01 Distribution Stations Demand Capital Program, Page 2587 of 2930.

*"**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?

OEB staff D29-171
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-02 Mobile Unit Substation Program, Page 2591 of 2930.

"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.

OEB staff D29-172
Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SR-03 Station Spare Transformer Purchases Program, Page 2601 of 2930.

*"**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.

OEB staff D29-173
Ref: Evidence Update, 2017-12-21 Exhibit Q/Tab1/Schedule 1 – 1.2 A reduction in the capital forecast; updated rate base and in-service additions forecasts.

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.

Issue 30. Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

OEB staff D30-174

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 1.1: Distribution System Plan Overview, Section 1.1.1 (5.2.1 A) KEY ELEMENTS OF THE DSP, Page 31 of 2930.

"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.

OEB staff D30-175

Ref: Exhibit B1/Tab1/Schedule 1 – DSP Section 3.8: (5.4.5.2) Attachments: Material Investments, ISD: SS-02 System Upgrades Driven by Load Growth, Page 2662 of 2930.

Ref: EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-02 System Upgrades Driven by Load Growth

"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).

Issue 31. Are the methodologies used to allocate Common Corporate capital expenditures to the distribution business appropriate?

Issue 32. Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

E. <u>RATE BASE & COST OF CAPITAL</u>

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

OEB staff E33-176
Ref: Exhibit D1/Tab1/Schedule 1/pg 2/Table 1

Table 1 provides a comparison of the 2017 Board-approved versus 2017 Bridge Year Forecast Rate Bases. In the text below Table 1, Hydro One states:

> “Total rate base in 2017 is expected to be $158.3 million above the OEB-approved amount. This variance of 2.2% is explained by higher in-service additions due to higher than forecast replacement of assets due to trouble

calls and storm damage, as well as joint use and relocation projects. In addition, a higher cash working capital requirement also contributes to the higher rate base. This is partially offset by lower demand for distribution generation connections and reduced spending on wood pole replacements."

a) Does Table 1 reflect the impacts of the Fair Hydro Plan which came into effect on July 1, 2017, particularly with respect to cost of power costs applicable to Residential, remote and First Nations ratepayers served by Hydro One?

b) If not, please update Table 1 to reflect the impact of the Fair Hydro Plan. Please provide Hydro One's analysis on the variance between the OEB-approved 2017 forecast and Hydro One's updated budget forecast.

OEB staff E33-177
Ref: Exhibit D1/Tab2/Schedule 1/pg 5/Table 1 – Cost of Capital Summary

Please update Table 1 of this exhibit, based on the updates to the working capital allowance requested for Exhibit D1-1-1/Tables 1, 2, 3 and 4 reflecting the Fair Hydro Plan which came into effect on July 1, 2017, and any other changes to the rate base for the test year period from 2018 to 2022.

OEB staff E33-178
Ref: Exhibit D2-1-1 – Statement of Utility Rate Base, D2-1-2 - Continuity of Property, Plant and Equipment, D2-1-3 – Continuity of Property, Plant and Equipment - Accumulated Depreciation, D2-1-4 - Continuity of Property, Plant and Equipment - Construction Work in Progress, D2-1-5 - Statement of Working Capital

Please update these tables to reflect the Fair Hydro Plan which came into effect on July 1, 2017 and any other changes to the components of rate base changed as a result of budget updates or responses to interrogatories.

OEB staff E33-179
Ref: Exhibit E1/Tab 1/Schedule 1 - Revenue Requirement, Determination of Net Utility Income

Please update tables in this exhibit to reflect the Fair Hydro Plan which came into effect on July 1, 2017 and any other changes to the components of rate base changed as a result of budget updates or responses to interrogatories.

OEB staff E33-180
Ref: Exhibit D2/Tab1/Schedule 2, Attachment 1

a) Please reconcile the asset continuity schedule to Note 10 of the applicant's December 31, 2016 audited financial statements (by total cost and total accumulated depreciation).

b) Please update the test period asset continuity schedule such that it reflects the impacts of the updates to the application as filed in Exhibit Q.

Issue 34. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

OEB staff E34-181
Ref: Exhibit D1-1-1/Page 4 – Cash Working Capital

Please update Hydro One's forecast of its Cash Working Capital for each of the test years to reflect the Fair Hydro Plan which came into effect on July 1, 2017, including the Tables in this exhibit.

Issue 35. Is the proposed capital structure appropriate?

Issue 36. Are the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rate implementation appropriate?

Issue 37. Is the forecast of long term debt for 2018 and further years appropriate?

OEB staff E37-182
Ref: Exhibit D2/Tab 2/Schedule 2

In its December 21, 2017 update, Hydro One updated its cost of capital to reflect the most recently released OEB cost of capital parameters but did not file a cost of capital long term debt table to reflect new issuances of debt and new forecasts of debt for 2018.

Please provide an updated schedule of actual debt issued in 2017 and the forecast of planned debt issuances and forecast of interest rates that would apply for the 2018 test year.

F. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

Issue 38. Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

OEB staff F38-183
Ref: Exhibit C1/Tab1/Schedule 1
Please update the OM&A schedules for 2017 actuals and for any other changes that may have taken place since the application was filed. Please highlight and explain any significant changes to the evidence.

OEB staff F38-184
Ref: Evidence Update, 2017-12-21, Exhibit Q/Tab1/ Schedule 1/pp 5-6
Hydro One includes Table 3 on page 5 with revised OM&A totals on page 6. The December 8, 2017 Business Plan is also included with similar tables for OM&A.

Please explain the differences in the 2018 OM&A numbers on page 6 with the OM&A numbers for 2018 on page 16 in the December 8, 2017 Business Plan.

OEB staff F38-185
Ref: Exhibit C1/Tab1/Schedule 2, pg 3
Table 1 shows that in almost all categories and all years from 2015 to 2017, Hydro One has consistently underspent approved amounts under Sustaining OM&A.

a) Why was Hydro One not able to meet planned or budgeted amounts, approved by the OEB?

b) What sacrifices were made by Hydro One in terms of reliability or customer service as a result of this underspending?

OEB staff F38-186
Ref: Exhibit C1/Tab1/Schedule 2, pg 3-4
Hydro One indicates that increased spending in 2018 is due to increases of $7 million to address a vegetation management backlog and reliability concerns and further increases of $12 million in lines demand work to address trouble calls to address customer expectations.

How does Hydro One reconcile these increases in spending, when it appears that these areas have suffered from an underspending in previous years, below OEB approved levels, and now increases are proposed?

OEB staff F38-187
Ref: Exhibit C1/Tab1/Schedule 2, pg 6
Table 2 shows that under the Planned Preventative Station Maintenance category, in all years from 2015 to 2017, Hydro One has consistently underspent OEB approved funding levels.

a) What are the major reasons that spending was curtailed from planned levels?

b) Did Hydro One consider the impact on reliability and that more spending would be required in future years to address station maintenance issues?

OEB staff F38-188
Ref: Exhibit C1/Tab1/Schedule 2, pg 14
Table 3 shows that there is underspending for Line Maintenance consistently from 2015 to 2017.

a) What are the major reasons that spending was curtailed from planned levels?

b) Did Hydro One consider the impact on reliability and that more spending would be required in future years to address line maintenance issues?

c) In the same table, Trouble Calls spending is higher than approved levels in all years and 2018 shows a 15% increase from 2017 approved levels. Please comment on the extent the Trouble Calls spending is driven by the underspending in Line Maintenance in previous years.

OEB staff F38-189
Ref: Exhibit C1/Tab1/Schedule 2, pg 15
Hydro One's evidence shows that proposed spending for the 2018 test year is based on an expected volume of trouble calls of 42,645 per year.

a) Please provide a table showing the number of trouble calls per year from 2012 to 2017.
b) Please comment on the trend of the cost per trouble call per year.

OEB staff F38-190
Ref: Exhibit C1/Tab1/Schedule 2, pg 16
With regard to Disconnects/Reconnects, Hydro One's evidence shows that proposed spending for the 2018 test year is based on an expected volume of 14,250 Disconnect/Reconnect calls per year.

a) Please provide a table showing the number of Disconnect/Reconnect calls per year from 2012 to 2017.

b) Please comment on the trend of the cost per Disconnect/Reconnect per year.
c) Hydro One also indicates on page 17 that the numbers of service Disconnect/Reconnect requests have increased over the past several years. Has Hydro One determined why this is the case?

OEB staff F38-191
Ref: Exhibit C1/Tab1/Schedule 2, pg 18
Under Maintenance, Hydro One states that proposed spending for the 2018 test year is based on an expected volume of 9,210 defect corrections per year.

a) Please provide a table showing the number of defect corrections per year from 2012 to 2017.
b) Please comment on the trend of the cost per defect correction per year.
c) Hydro One also indicates on page 19 that it expects an increase in the level of defect corrections. Has Hydro One determined why defect corrections are on the rise?

OEB staff F38-192
Ref: Exhibit C1/Tab1/Schedule 2, pg 20
Table 3 shows that there is consistent underspending (from approved levels) for PCB Equipment and Waste Storage from 2015 to 2017.

a) What are the major reasons that spending was curtailed from planned levels?
b) Did Hydro One consider the environmental impact of this lower than planned spending?
c) If so, what was the rationale for the reduced spending?
d) Hydro One also states, on page 20 that proposed spending for the 2018 test year is based on an expected volume of 27,595 PCB Inspections and Testing per year. Please provide a table showing the number of PCB Inspections and Testing per year from 2012 to 2017.
e) Please comment on the trend of the cost per Inspection/Test per year.

OEB staff F38-193
Ref: Exhibit C1/Tab1/Schedule 2, pg 23
Table 4 shows that Telecom, Monitoring and Control spending jumps by 68% in 2017 and continues at that level in 2018 ($6.4 million).

What was the cause for this increase in spending and why has Hydro One proposed to continue spending at this level in the 2018 test year?

OEB staff F38-194
Ref: Exhibit C1/Tab1/Schedule 2, pg 29
Table 5 again shows that Vegetation Management spending in each of the 2015, 2016 and 2017 years is below OEB approved levels. Yet, Hydro One's evidence refers to a backlog of maintenance.

a) If Hydro One was aware of backlogs in vegetation management, why did it not at least spend to the approved levels?

b) To what extent is the demonstrated underspending on Vegetation Management contributing to the increase in 2018 levels of Demand Vegetation Management to $10.2 million well above the OEB approved levels of $6.8 million and $6.9 million for 2016 and 2017 respectively?

c) Please provide a table showing the km of Line Cleared and km of Line Brush Control (as in past applications) per year from 2012 to 2017.

d) Please comment on the trend of the cost per km of Line Cleared and km of Line Brush Control and also indicate how its three changes for the Vegetation Management program as noted on page 28, will contribute to lower costs in 2018 and beyond.

OEB staff F38-195
Ref: Exhibit C1/Tab1/Schedule 2, pg 30
Ref: Evidence Update, 2017-12-21, Exhibit Q/Tab1/ Schedule 1/pp 13-15
At this reference, Hydro One states that it will now clear lines at an "optimal cycle length which is between four and eight years", based on the vegetation benchmarking study. Yet in its December 21, 2017 Update (Exhibit Q), Hydro One changes its objective to pursue a 3 year cycle.

a) How can Hydro One make such a radical change to its vegetation management program in such a short space of time?

b) Under the new program, how will Hydro One keep vegetation management spending at currently planned levels while moving from a 4 to 8 year cycle to a 3 year cycle?

c) Please define the term 'defect'. How does a 'defect based approach' differ from previous practice? Please provide specific examples.

d) On what basis does Hydro One say that its vegetation management costs will decrease? Has this increase in efficiency been included in productivity claims?

OEB staff F38-196
Ref: Exhibit C1/Tab1/Schedule 3, pg 1
Table 1, the Summary Table, again shows that Hydro One has consistently underspent its OEB-approved OM&A budgets on Development from 2015 to 2017.

Has Hydro One considered the impact on reliability and customer satisfaction that this lower than approved development spending (across all budget categories) will have?

OEB staff F38-197
Ref: Exhibit C1/Tab1/Schedule 4, pg 1
Table 1 shows a summary of Operations OM&A, highlighting the 4 categories of spending. In three categories, Operations Support, Environment Health and Safety and Smart Grid, spending is significantly below OEB-approved levels.

Has Hydro One considered the impact on reliability, customer satisfaction and Health and Safety that this lower than approved operations spending will have?

OEB staff F38-198
Ref: Exhibit C1/Tab1/Schedule 4, pg 4
At this reference, under the Smart Grid category, Hydro One indicates that it delayed the rollout of the Distribution Management System upgrade which will now be completed in 2018.

a) What was the cost of delaying the Distribution Management System upgrade and what were the expected benefits for Hydro One?

b) Is the implementation delay responsible for the 40% increase in costs for 2018?

c) To what extent is the 2018 budget a one-time cost of implementation?

OEB staff F38-199
Ref: Exhibit C1/Tab1/Schedule 5, pg 3
At this reference, under Call Centre Operations, Hydro One indicates that the call center handled over 2.7 million calls from customers and responded to over 63,000 emails.

a) Please provide a table showing these statistics per year from 2012 to 2017.

b) Please comment on the trend of the cost per customer call response per year.

OEB staff F38-200
Ref: Exhibit C1/Tab1/Schedule 5, pp 4-5
Under Meter Reading, Hydro One indicates that approximately 150,000 meters require a manual meter read due to the limited geographical reach of the Smart Meter Network infrastructure.

a) To what extent is Hydro One striving to reduce the number of meters that require manual meter reading?

b) What are the targets to reduce manual reading over the course of the IRM period?

c) Hydro One also indicates that as a result of amendments to the DSC, requiring distributors to install an interval meter in any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW, spending will be higher in 2017 and 2018. How many additional meters will have to be installed as a result of these amendments?

OEB staff F38-201
Ref: Exhibit C1/Tab1/Schedule 5, pg 5
Hydro One mentions that a new e-billing solution was launched at the end of 2016 to reduce postage and other costs.

a) How is this new e-billing solution a better option for the customer than previous practice?
b) What are the expected savings to be had from this solution?
c) What is the status of the roll-out of this e-billing solution at the end of 2017?
d) Have Hydro One's expectations for this new e-billing solution been met? Why or why not?
e) Why does this new e-billing solution not result in lower costs, mitigating the increase in 2018 costs, currently set at $14.6 million?

OEB staff F38-202
Ref: Exhibit C1/Tab1/Schedule 5, pp 8-9
Hydro One mentions that it suspended its collections program from 2013 to early 2016 related to the implementation of CIS.

a) Please provide further information as to why the collections program was suspended and how the suspension related to the new CIS system.

b) On page 9, Hydro One indicates that it is committed to reducing Net Bad Debt as a percentage of revenue from 2017 to 2022. What are Hydro One's targets in this regard and, if targets are met, what are the expected cost reductions Hydro One expects to achieve?

c) In this light, why are Net Bad Debt costs for 2018 set at the $21.1 million level, a 46% increase over OEB approved levels in 2017?

OEB staff F38-203
Ref: Exhibit C1/Tab1/Schedule 5, pg 13
Table 11 shows a number of Operational Effectiveness Outcomes with some cost savings estimates for each area.

a) Under My Account Self-Service, there are no targets cited for increasing the uptake of this service. Please provide the current level of uptake; Hydro One's targets for the 2018 – 2022 period; and the projected cost savings as more customers move to self-service.

b) Under e-billing, Hydro One indicates that 545,000 customers are expect to sign up by 2022 and that this will result in $17 million in OM&A savings due to reduced postage costs. What is the current uptake of e-billing? Are the projected savings reflected in the 2018 OM&A forecast?

c) Under Remote Disconnect, Hydro One indicates that Field Support OM&A expenditure will decline by $3 million annually. How are these projected savings reflected in the 2018 OM&A forecast?

Issue 39. Do the proposed OM&A expenditures include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences?

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)?

OEB staff F40-204
Ref: Exhibit C1/Tab2/Schedule 1, p 9
Table 1 shows Full Time Equivalents from 2017 to 2022 for various employee categories. For 2017 the number of Casual employees is 2802 or about 33% of the total FTEs. This ratio remains the same for 2022.

a) Does Hydro One consider the 33% ratio to be optimal in terms of casual employees?

b) Will the percentage of Casual employees be increased into the 2019 – 2022 period?

OEB staff F40-205
Ref: Exhibit C1/Tab2/Schedule 1, p 9
Has Hydro One conducted a Staffing study to compare its staffing levels to other distributors and determine the optimal staffing level for its operations?

If so, please file this study or studies, and provide a rationale for current and planned staffing numbers. If not, why not?

OEB staff F40-206
Ref: Exhibit C1/Tab2/Schedule 1, pp 11-13
On these pages Hydro One summarizes efforts underway to manage the total FTE complement and increase efficiency.

Please provide the estimated savings for each initiative for the 2018 test year and future years, under the various categories: Construction (flexible workforce); Engineering (standardized processes, organizational alignment, external resources); Lines (consolidation of first line managers, outsourcing, Move to Mobile and planning for Pole Replacements); Forestry (efficiency initiatives and the "Muskoka Project"); and Stations Maintenance (temporary workforce and new scheduling tool).

OEB staff F40-207
Ref: Exhibit C1/Tab2/Schedule 1, pg 33
Hydro One indicates the base salary increases of 2% for MCP staff, 1% for PWU staff and 0.5% for Society staff for the IRM period. Then Hydro One states that over the test period, total compensation for the Distribution business increases by 2.5%.

Please explain how the individual increases mentioned total to the 2.5% aggregate number.

OEB staff F40-208
Ref: Exhibit C1/Tab2/Schedule 1, pg 39
In addressing the Mercer study results at point 4, Hydro One indicates, "The study does not account for the impact of Hydro One's negotiated cost-saving initiatives such as future pension benefit reductions or the updated pension valuation filed with the OEB."

a) How significant are these factors to the total results of the study?
b) When does Hydro One plan to conduct another Mercer Study?

OEB staff F40-209
Ref: Exhibit C1/Tab2/Schedule 1, pg 43
Table 13 shows the annual savings from the increase in employee pension contributions from 2018 to 2022.

Please provide the methodology used to calculate these savings.

OEB staff F40-210
Ref: Exhibit C1/Tab2/Schedule 1, pg 44
Hydro One mentions the move of the employer/employee pension cost sharing ratio to 50-50.

a) How has this ratio changed from the time Hydro One became a stand-alone distributor (for both Society and PWU employees), in each year to 2017?

b) What are the assumptions for these ratios from 2018 to 2022?

Pensions and OPEBs

OEB staff F40-211
Ref: Exhibit C1/Tab2/Schedule 2
In its September 14, 2017 Report on the Regulatory Treatment of Pension and OPEB costs (OEB Report), the OEB indicated that utilities proposing to set rates using a method other than accrual must support such a proposal with evidence, giving consideration to factors such as providing value to customers and assuring fairness to both present and future ratepayers, and the principles and practices enunciated in the OEB Report.

Hydro One has proposed to recover its test period pension costs on a cash basis. Hydro One indicates that it believes that this method is more beneficial to its customers than the accrual method as it results in a lower cost recovered through rates, it is more predictable, and the OEB has historically accepted the cash method as the basis for the recovery of its pension obligations.

a) In accordance with the OEB Report, please provide evidence that supports the appropriateness of Hydro One's use of the cash method to recover its pension costs. Please ensure that the evidence provided addresses the required areas as specified in OEB Report.

b) In indicating that the cash method results in lower costs being recovered through rates, Hydro One, however has not provided any analysis to support this statement. Please prepare an analysis similar to the one provided for OPEBs in Table 2 of Exhibit C1/Tab2/Schedule 2, comparing on historical basis, the cash amount recovered in rates and the accrual expense related to Hydro One's annual pension obligations.

OEB staff F40-212
Ref: Exhibit C1/Tab2/Schedule 2
Does Table 1 of Exhibit C1-2-2 include the contribution requirements for the defined contribution pension plan as well?

a) If the response above is no, then please provide a table similar to Table 1 that presents the test period contribution requirements for the defined contribution pension plan.

b) Is the test period amount related to the defined contribution pension plan being underpinned by an actuarial valuation? If so, please provide. If not, then please explain how an estimate of the contributions is being made and provide the relevant support.

OEB staff F40-213
Ref: Exhibit C1/Tab2/Schedule 2, Attachment 1

Section 3.1 of the actuarial valuation for the defined benefit pension plan illustrates the minimum employer pension contributions for the period 2017-2019. This section indicates that the contributions will be funded through Plan surpluses.

Does this mean that the applicant will not be funding these contributions with cash from its operations? Please explain.

OEB staff F40-214
Ref: Exhibit C1/Tab2/Schedule 2, Attachment 1

Section 3.1 of the actuarial valuation for the defined benefit pension plan illustrates the minimum employer pension contributions for the period 2017-2019. This section indicates that the contributions will be funded through Plan surpluses.

Does this mean that the applicant will not be funding these contributions with cash from its operations? Please explain.

OEB staff F40-215
Ref: Exhibit Q/Tab1/Schedule 1

As per the December 21, 2017 update, the estimate of the test period OPEB costs has changed as a result of an updated actuarial valuation.

a) Please provide the updated OPEB cost amount for the test period.in a table consistent with Table 1 of Exhibit C1/Tab2/Schedule 2.

b) Please provide the updated OPEB valuation.

OEB staff F40-216
Ref: Exhibit C1/Tab2/Schedule 2

In Table 2, Hydro One provides a historical summary of OPEB costs it has recovered in rates (on an accrual basis) compared to the related cash payments for the same period.

The analysis indicates that Hydro One has historically over-collected with respect to its OPEB costs.

Please explain how these over-collections have been used.

OEB staff F40-217
Ref: Exhibit C1/Tab2/Schedule 2, Section 5.1

At this reference, Hydro One discusses an update to the US GAAP accounting standard for pension and OPEB costs that is effective from January 1, 2018, which has an impact on the pension and OPEB amounts for the test period.

a) Please explain why Hydro One has proposed to capture the test period impact of this new standard in a variance account rather than updating its application.

b) Please provide a table that summarizes the impact that this new accounting standard has on the test period revenue requirement.

Issue 41. Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs (excluding executive compensation)?

Issue 42. Is the updated executive compensation information filed by Hydro One in the distribution proceeding on December 21, 2017 consistent with the OEB's findings on executive compensation in the EB-2016-0160 Transmission Decision?

Issue 43. Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?

G. <u>REVENUE REQUIREMENT</u>

Issue 44. Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

OEB staff G44-218
Ref: Exhibit C1/Tab6/Schedule 1

From the evidence filed in the above reference, it is not clear what actually underpins Hydro One's estimate for the amortization related to its environmental costs.

a) Please explain how this balance is estimated and provide evidence that supports the estimate for the test period.

b) Please provide a table that compares the amount collected in rates over the last 5 years (2013-2017) with respect to amortization of environmental costs and the actual amortization as per the audited financial statements for the same period.

Issue 45. Are the proposed other revenues for 2018 – 2022 appropriate?

H. <u>LOAD AND REVENUE FORECAST</u>

Issue 46. Is the load forecast methodology including the forecast of CDM savings appropriate?

OEB staff H46-219
Ref: Exhibit E1/Tab2/Schedule 1, p 7
The load forecast was last updated June 7, 2017 using data available in January 2017. Since then, Hydro One prepared a partial update of the application in December 2017.

Please file an update of the load forecast using 2017 actual consumption information, or as much of 2017 as possible. Please also update for updates to explanatory variables including actual and normal weather, as well as historic and forecast economic data.

OEB staff H46-220
Ref: Exhibit E1/Tab2/Schedule 1, pp 1 and 13
Hydro One assumes typical weather conditions based on the average of the last 31 years.

a) Please confirm that the comparisons in Table 5 on page 13 of the Load Forecast evidence are based on averages of the last 20 and 10 years.

b) If part a) cannot be confirmed, please explain.

c) Please prepare a forecast run using a 20 year trend definition of normal weather.

OEB staff H46-221
Ref: Exhibit E1/Tab2/Schedule 1/pg 11 – Load Forecasting Methodology
On page 11, Hydro One provides the following:

> *"Hydro One Distribution's load forecast is developed using both econometric and end-use approaches. The load impacts of CDM are added back to the historical values during the modeling process (see Figure 2 below)."*

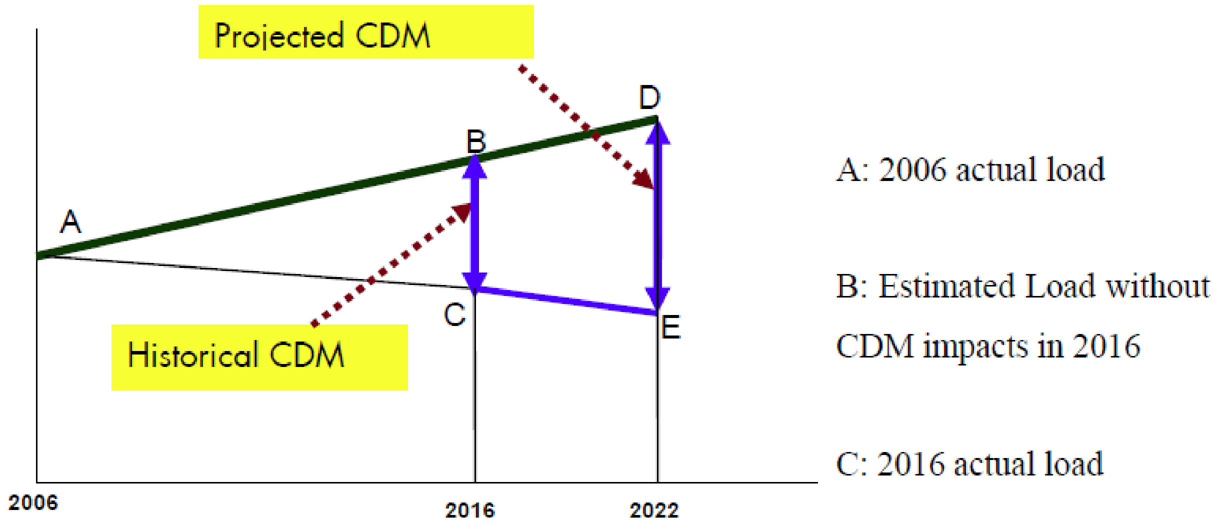


Figure 2: Incorporation of CDM in the Load Forecast

The forecast base-year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base-year value. The forecast is weather-normal in the sense that it predicts the future load under normal weather conditions.

a) What are the points "D" and "E" in Figure 2?

b) Please provide a more precise explanation of Hydro One's methodology for incorporating or otherwise adjusting for historical actual and forecasted CDM in its load forecast.

OEB staff H46-222
Ref: Exhibit E1/Tab2/Schedule 1, p 17
In producing 2015 load profiles, 2015 actual hourly smart meter and interval meter data was used. Where hourly data was not available for all customers, the available hourly data was scaled up to the 2015 actual load for the rate class.

Has Hydro One considered other methods, such as calculating an hourly residual net of known hourly customers, and estimated losses in developing the hourly load profile for each rate class? Please describe.

OEB staff H46-223
Ref: Exhibit E1/Tab 2/Schedule 1, pp 22-23

Appendix A provides a description of the monthly model. Page 2 provides the coefficient estimates. Please explain the following:

a) A[1]

b) K[1]

c) GDPONT[-4]. Does the [-4] mean that the variable is lagged by four months? What is the rationale for this lag, and why is the current month's value not relevant?

d) BPONT[-8]. Does the [-8] mean that the variable is lagged by eight months? What is the rationale for this lag? Further, on page 1, Hydro One defines the variable LBPONT as "logarithm of Ontario residential building permits in constant dollar". How is this variable expressed in dollars?

e) How were the appropriate lags for Ontario GDP and Ontario building permits determined?

OEB staff H46-224
Ref: Exhibit E1/Tab 2/Schedule 1, pp 24-26 – Annual Retail Load Model

Hydro One specifies the following equation format for the annual Retail Load Model:

> LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-4)-LPGASRES(-4))+C(4)*LHDD+C(5)*LRTLT(-1)-C(4)*C(5)*LHDD+C(6)*D99A+C(7)*TR+C(8)*TR2+C(9)*D08ON

and defines the terms following:

> LRTLT = logarithm of retail load,
>
> LYPDPHH = logarithm of Ontario personal disposable income per household / house in constant dollar,
>
> - History is based on disposable income in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistics Canada and divided by the number of households / houses based on IHS Global Insight housing starts
>
> - Forecast is based on forecasts of disposable income from C4SE, University of Toronto (PEAP) and Conference Board of Canada deflated by CPI from IHS Global Insight and divided by the number of household / houses based on consensus forecast of housing starts as presented in Appendix E
>
> LPELRES = logarithm of electricity price for Ontario residential sector

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016

- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016 Outlook

- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

TR2 = TR to power 2,

D08ON = a dummy variable to account for economic changes, equals zero prior to 2008 and 1 elsewhere.

C(1) – C(9) = variable coefficients.

OEB staff notes that, since the model is specified in double-log (double-logarithmic) form, the coefficients of variables such as income and price can be interpreted as the elasticities of demand. For example, C(2) is the income elasticity of demand.

OEB staff notes that the regression equation could be written as follows, after rearranging terms:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*LPELRES(-4)-C(3)*LPGASRES(-4)
+C(4)*(1+C(5))*LHDD+C(5)*LRTLT(-
1)+C(6)*D99A+C(7)*TR+C(8)*TR2+C(9)*D08ON

a) Do LPELRES(-4) and LPGASRES(-4) mean that these variables are lagged by 4 years? If so, why does demand depend of such prices that are lagged so long, and not on current prices?

b) Are PELRES (residential electricity price) and PGASRES (residential natural gas price) specified in real (adjusted for inflation) or nominal terms?

c) As OEB staff has written it, C(3) is the price elasticity of demand and –C(3) is the cross-price elasticity of demand with respect to natural gas prices. The estimated coefficient is -0.013723, but is statistically insignificant (*t*-statistic of -1.04), as shown on page 26. This means that, all else being equal, a 1% increase in the price of electricity results in a 0.013723% decline in electricity consumption.

i. Hydro One's specification assumes that the price elasticity of demand and the cross-price elasticity of demand with respect to natural gas prices are equal in magnitude. What is the basis for Hydro One's assumption?

ii. While electricity demand is basically assumed to be price inelastic (i.e. price elasticity between 0 and -1), does Hydro One believe that the price elasticity of electricity demand is so small? Please explain your response.

d) What is the purpose of specifying the coefficient of LHDD as C(4)+C(4)*C(5) = C(4)*(1+C(5))?

e) Please confirm that LRTLT(-1) means that annual demand lagged one year is used as a regressor variable.

f) Why is HDD at Pearson Airport considered to be a suitable explanatory variable for weather impacts for Hydro One's expansive service territory?

g) Why is there no variable for CDD (Cooling Degree Days)?

OEB staff H46-225
Ref: Exhibit E1/Tab2/Schedule 1, pp 24-26
In the Retail Load forecast, several coefficients have a t-ratio between -2.0 and 2.0 indicating a lack of certainty in the statistical significance of the variables, including C(3), C(4), and C(9) relating to LPELRES(-4)-LPGASRES(-4), LHDD, and D08ON.

a) Has Hydro One tested other variables related to differences in fuel costs, heating degree days, and the economic changes of 2008?

b) Has Hydro One considered forecasting using explanatory variables rather than logarithms of explanatory variables?

OEB staff H46-226
Ref: Exhibit E1/Tab2/Schedule 1, pp 24-26
The prior year retail load forecast, LRTLT(-1) is used in generating the current year forecast.

Please prepare a sensitivity of a 5% change in the 2018 forecast on the results of 2019, 2020, 2021, and 2022.

OEB staff H46-227
Ref: Exhibit E1/Tab2/Schedule 1, pp 27-28 – Annual Embedded LDC Load Model
Hydro One specifies the following equation format for the annual Embedded LDC Load Model:

LEMBLDCS=C(1)+C(2)*D(LHHOLD)+C(3)*(LPELRES(-1)-LPGASRES(-1))
+C(4)*LCDD+C(5)*LHDD+C(6)*LEMBLDCS(-1)-C(4)*C(6)*LCDD(-1)-
C(5)*C(6)*LHDD(-1)+C(7)*TR

and defines the terms as:

LEMBLDCS = logarithm of Embedded LDC load,

LHHOLD = logarithm of Ontario number of households / houses,
- History from IHS Global Insight housing starts
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

LPELRES = logarithm of electricity price for Ontario residential sector
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2016 Outlook
- Forecast is from NEB 2016 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPGASRES = logarithm of natural gas price for Ontario residential sector,
- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2016
- Forecast is from NEB 2016 Outlook accounting for carbon tax

LHDD = logarithm of heating degree days for Pearson International Airport,

D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,

TR = a dummy variable to account for a shift in growth pattern of distribution load, increases by 1 per year prior to 1989 and no increase afterwards,

C(1) – C(7) = variable coefficients.

a) Please provide the definition of the variable LCDD. If this is the logarithm for Cooling Degree Days as measured by Environment Canada at Pearson Airport, please explain how CDD at Pearson Airport is considered appropriate for the demand of all of the embedded distributors served by Hydro One Networks distribution throughout Ontario.

b) Why is HDD at Pearson Airport considered to be a suitable explanatory variable for weather impacts for Hydro One's expansive service territory with respect to the energy demand/consumption of embedded distributors served by One Networks distribution throughout Ontario?

c) Hydro One provides the following estimates and associated statistics for the model coefficients:

	Estimated Coefficient	Standard Error	*t*-Statistic
C(1)	1.763528	0.621723	2.836516
C(2)	1.586283	0.916446	1.730908
C(3)	-0.046937	0.016798	-2.794270
C(4)	0.007978	0.009718	0.820939
C(5)	0.012515	0.058312	0.214612
C(6)	0.781907	0.076054	10.28089
C(7)	0.010703	0.004228	2.531607

C(4) is the coefficient for LHDD and C(5) is the coefficient for LCDD. Both coefficients have low *t*-statistics and are statistically insignificant at even a 90% confidence level. Why has Hydro One retained these variables given their insignificant estimated coefficients?

d) C(3) is the price elasticity of demand, and has an estimated value of -0.46937. In the Retail Load Model for Hydro One's directly served end customers, the estimated price elasticity of demand is estimated at -0.013723. Notwithstanding that the two estimates may not be statistically significantly different, please provide Hydro One's views on whether these estimated price elasticities for the two segments are reasonable from a conceptual economic basis.

OEB staff H46-228
Ref: Exhibit E1/Tab2/Schedule 1, pp 27-28
In the Embedded LDC load forecast, three coefficients have a t-ratio between -2.0 and 2.0 indicating a lack of certainty in the statistical significance of the variables, including C(2), C(4), and C(5) relating to LHHOLD, LCDD, and LHDD. C(5) in particular has a t-stat of only 0.214612 indicating very little certainty of statistical significance at all.

a) Has Hydro One tested other variables related to differences in fuel costs, heating degree days, and the economic changes of 2008?

b) Has Hydro One considered forecasting using explanatory variables rather than logarithms of explanatory variables?

OEB staff H46-229
Ref: Exhibit E1/Tab2/Schedule 1, pp 27-28
The prior year forecast, LEMBLDCS(-1) is used in generating the current year forecast.

Please prepare a sensitivity of a 5% change in the 2018 forecast on the results of 2019, 2020, 2021, and 2022.

OEB staff H46-230
Ref: Exhibit E1/Tab2/Schedule 1, pp 39 and 41
Table E.5 normalized energy use for Hydro One Distribution and Table E.7 weather corrected sales and forecast do not match.

Please reconcile the apparent discrepancy between Tables E.5 and E.7 for all years.

OEB staff H46-231
Ref: Exhibit E1/Tab2/Schedule 1, pp 39- 41
The tables supplied include the effect of acquired utilities in 2021 and 2022.

a) Please provide versions of E.4, E.6, and E.7 which exclude the acquired utilities.

b) Please provide versions of E.4, E.6, and E.7 which include only the acquired utilities for all 2011 – 2022, or all available years.

OEB staff H46-232
Ref: Exhibit E1/Tab2/Schedule 1
The Fair Hydro Plan (FHP) will have an impact on retail electricity prices which will vary by customer class, over the 4 year scope of the FHP. All else being equal, the Fair Hydro Plan should have a stimulative impact on kW and kWh.

a) Has Hydro One considered the impact of the FHP on its load forecast?
b) If the answer to part a) is no, why not?
c) If the answer to part a) is yes, what are the impacts?
d) If the impacts are not significant, why not?
e) If the impacts are significant, please explain how the FHP was taken into account or how the load forecast will be amended.

OEB staff H46-233
Ref: Exhibit E1/Tab2/Schedule 1, Attachment 2, pp 15-16
Appendix 2-I was filed prior to the release of the 2018 Chapter 2 Appendices. The default weighting factor for the most recent historic year is 0.5 reflecting that half of the CDM savings are already reflected in the historic load. The default weighting factor for the test

year is 0.5 reflecting that on average, CDM programs are delivered half way through the year, and therefore only realize savings for half a year.

a) Why has Hydro One chosen a weighting factor of 1.0 for both 2016 and 2018 reflecting that all CDM delivery in those years would serve to reduce the 2018 load forecast?

b) Please provide an updated Appendix 2-I based on the current Chapter 2 Appendices. Recognizing the update to include 2017 historic actual usage in ExE-Staff-03, please weight 2016 CDM savings at 0, 2017 CDM savings at 0.5, and 2018 CDM savings at 0.5, or explain why this would not be appropriate.

OEB staff H46-234
Ref: Decision, March 12, 2015 (EB-2013-0416), Page 51
Ref: Exhibit E1, Tab 1, Schedule 2, Pages 5-8
Ref: Exhibit H1, Tab 2, Schedule 3, Pages 4-8
In the decision referenced above, Hydro One was directed to file "a study assessing whether its service charges reflect Hydro One's underling costs and to propose changes accordingly." This was in response to a concern of Sustainable Infrastructure Alliance (SIA) that "Hydro One's charges for miscellaneous services significantly under-recover the true cost of the services." The results of that study are included in Exhibit H1/Tab 2/ Schedule 3, and the impact on revenue is seen in Exhibit E1/Tab1/Schedule 2.

a) Several charges in the reference at Exhibit H1, e.g. rate code 26 have current approved and updated 2018 proposed charges, while at the same time do not appear in Exhibit E1.
   i. Are these charges being applied to existing customers?
   ii. If so, why are they not included in the reference in Exhibit E1?
   iii. If not, how was the appropriate charge calculated in the reference in Exhibit H1?

b) The Miscellaneous Service Revenue is expected to increase from $18.7 million to $21.2 million. Is Hydro One expecting that this will address the significant under-recovery concern of SIA?

Issue 47. Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

Issue 48. Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?

I. COST ALLOCATION AND RATE DESIGN

Issue 49. Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?

OEB staff I49-235
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab I2 LDC Class
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab I2 LDC Class
The summary of the run cell is not populated. The contents of this cell appears on the header of all other worksheets in the model, and is useful for parties to be certain of which model run they're looking at when examining model printouts.

Please populate this cell with a meaningful description, unique to each run.

OEB staff I49-236
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab I4 BO Assets
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab I4 BO Assets

The Contributed Capital – 1995, cell C103, and Accumulated Depreciation – 2015, cell C104 have had formulas overtyped with values. Cell I104 does not balance with cell C104.

a) Please explain why the formulas were overtyped for both the 2018 and 2021 models.

b) Please reconcile cell G103 back to the trial balance account 1995 for both the 2018 and 2021 models.

c) Please reconcile cell I104 back to the trial balance for account 2015 for both the 2018 and 2021 models.

OEB staff I49-237
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab I6.2 Customer Data
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab I6.2 Customer Data
Ref: OEB Letter: "Review of Cost Allocation Policy for Unmetered Loads", June 12, 2015
Ref: "Cost Allocation to Different Types of Street Lighting Configurations" EB-2012-0383, June 12 2015, Navigant
The provided Cost Allocation models have calculated the Street Light Adjustment Factor (SLAF) for Primary distribution, and applied this to Total number of customers, Bulk Distribution, and Primary Distribution. The provided Cost Allocation models have also calculated the SLAF for Line Transformer, and applied this to Line Transformer and Secondary. In its report, Navigant recommended, and in its letter, the OEB adopted no changes to the existing connection based cost allocation for secondary distribution.

a) The default cost allocation model only applies the SLAF for Primary distribution to the Primary connection count. Why has Hydro One chosen to apply this amount to the Total Number of Customers as well?

b) The default cost allocation model only applies the SLAF for Line Transformer to the Line Transformer Customer Base. Why has Hydro One chosen to apply this amount to the Secondary Customer base as well?

c) How many connections are made to the secondary system by the street lighting rate class?

OEB staff I49-238
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab I6.2 Customer Data
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab I6.2 Customer Data
Hydro One has entered that it plans to prepare 63,879 Street Lighting bills in 2018, and 65,336 Street Lighting bills in 2021.

a) Please confirm how many customers Hydro One forecasts to have in each of 2018 and 2021, and on average, how many bills it plans to issue to each.

b) If Hydro One plans to bill a customer more than 12 times per year, please explain.

OEB staff I49-239
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab I6.2 Customer Data
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab I6.2 Customer Data
Hydro One has entered that it plans to prepare 67,167 USL bills for 5,597 customers related to 5,597 connections in 2018, and 71,334 USL bills for 5,944 customers related to 5,944 connections in 2021.

a) Please confirm that Hydro One treats each connection as a separate customer, and bills each one separately.

b) If part a) cannot be confirmed, please revise the model to reflect the connection, customer, and billing counts.

OEB staff I49-240
Ref: G1-03-01-03 Cost Allocation Model for 2018, Tab O1 Revenue to Cost|RR
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab O1 Revenue to Cost|RR
The Allocated Rate Base does not reconcile with the input on sheet I3. This discrepancy exists in both the 2018 and 2021 models.

Please reconcile the allocated Rate Base to the input on sheet I3, and correct if appropriate.

OEB staff I49-241
Ref: Exhibit G1/Tab3/Schedule 1, pp 3-4
Hydro One is proposing to use the billing and collecting weighting factors from the 2017 model.

Please provide the derivation of the Billing and Collecting factors used and please identify the year of any data used, and whether it was an actual or forecast basis.

OEB staff I49-242
GFA Adjustment Factors
Ref: Exhibit G1/Tab3/Schedule 1, p 7 and Exhibit Q/Tab1/Schedule 1, p 15
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab E2 Allocators
Ref: Exhibit Q1-01-01_20171221, Tab E2 Allocators
Hydro One is proposing GFA adjustment factors ranging from 0.177 to 0.667 for the acquired rate classes.

a) Please confirm that these adjustment factors serve to reduce the fixed assets allocated to the acquired rate classes.

b) Please confirm that the amount reduced from the acquired rate classes, is then re-allocated back to the existing Hydro One rate classes, and this effectively gives the existing rate classes GFA adjustment factors in excess of 1.00.

c) Please provide calculations underpinning the GFA adjustment factors chosen.

d) Does Hydro One intend to continue to update the GFA adjustment factors in future rate applications? If so, what measures is Hydro One taking to keep the values current. If not, why not?

OEB staff I49-243
NFA Adjustment Factors
Ref: Exhibit G1, Tab 3, Schedule 1, Page 7 and Exhibit Q, Tab 1, Schedule 1, pg 15
Ref: G1-03-01-04 Cost Allocation Model for 2021, Tab E2 Allocators
Ref: Exhibit Q1-01-01_20171221, Tab E2 Allocators
Hydro One is proposing NFA adjustment factors ranging from 0.208 to 0.678 for the acquired rate classes.

a) Please confirm that these adjustment factors serve to reduce the net assets allocated to the acquired rate classes.

b) Please confirm that the amount reduced from the acquired rate classes, is then re-allocated back to the existing Hydro One rate classes, and this effectively gives the existing rate classes NFA adjustment factors in excess of 1.00.

c) Please provide calculations underpinning the NFA adjustment factors chosen.

d) Does Hydro One intend to continue to update the NFA adjustment factors in future rate applications? If so, what measures is Hydro One taking to keep the values current. If not, why not?

OEB staff I49-244
Adjustment Factors
Ref: Exhibit Q/Tab1/Schedule 1, p 16
Hydro One states that they have "added distribution station equipment (US of A accounts 1815 to 1820) to the assets that should be included in the adjustment factor calculations."

a) For any distribution station equipment in service prior to the merger, was this equipment owned by acquired utilities or by Hydro One?

b) For any distribution station equipment in service since the merger, would this equipment have been owned by the acquired utilities or Hydro One had the utilities not been acquired?

c) If the response to a) and/or b) indicates that the equipment was owned by Hydro One, or would have been if not for the LDC acquisition, please describe the how the value included in each acquired LDC's accounts 1815 and 1820 was derived.

d) Is the distribution station equipment dedicated to serving customers of the acquired utilities, or does it also serve legacy customers of Hydro One or other LDCs?

OEB staff I49-245
Ref: Exhibit E1/Tab1/Schedule 1, p 4 and Exhibit H1/Tab1/Schedule 2
Ref: EB-2013-0416, dated 2014-05-30, Exhibit G1/Tab4/Schedule 1, p 16
At the first reference, referring to the revenue requirement workform (RRWF), Hydro One states "Tabs 10 through 13 of the workform have not been completed as the template does not allow for the necessary flexibility required for Hydro One's cost allocation and rate design requirements." Tab 12 of the RRWF provides the expected methodology for the implementation of the new rate design policy for residential customers.

a) Please explain why Hydro One could not have used one instance of Tab 12 for each transition year in each rate residential rate class. What flexibility was missing?

b) Please provide a derivation of proposed fixed charges for each residential class in each year using either Tab 12 of the RRWF, or an alternative worksheet which replicates the functionality to the extent possible.

OEB staff I49-246
Ref: Exhibit H1/Tab1/Schedule 1, pp 24-25
Ref: EB-2013-0416, dated 2014-05-30, Exhibit G1/Tab4/Schedule 1, p 16
In its previous rate application, Hydro One projected an increasing Hopper Foundry Lost Revenue amount in each year. In 2015, the lost revenue was expected to be $91,195, and by 2018 was expected to be $124,974. In this application, Hydro One expects the lost revenue for 2018 to be $62,040, and expects the lost revenue to increase each year.

a) Please explain the discrepancy between the previous rate application and this rate application.

b) Please provide a derivation of the 2018-2022 Hopper Foundry Lost Revenue outlining the changes that are expected to result in the increasing Lost Revenue Amount.

OEB staff I49-247
Depreciation Cost Adjustment
Ref: Exhibit G1/Tab/3/Schedule 1, p 8
Hydro One is proposing to apply the GFA adjustment factors to the depreciation expense.

a) Has Hydro One considered the use of depreciation expense of the assets used the serve the acquired rate classes instead? I.e. created a new depreciation adjustment factor based on the methodology used to create the GFA.

b) If the answer to a) is no, why not? If the answer to a) is yes, what was the result?

Issue 50. Are the proposed billing determinants appropriate?

Issue 51. Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

OEB staff I51-248
Ref: EB-2013-0416 Decision, March 12, 2015, p 45
Ref: Exhibit H1/Tab1/Schedule 1, pp 10-14

In the decision referenced above, “The OEB directs Hydro One to move its ratios to 90% - 110% over the three year period for which rates are approved.” However, in the current rate application, on page 10 of the reference in Exhibit H1, Hydro One has stated “By

2020, the DGen rate class R/C ratio will be within the Board-approved range and no further adjustments will be required to any of the R/C ratios." Table 7 on page 11 indicates a R/C ratio of 0.81 or 81% for DGen.

a) In Hydro One's view, should the OEB decision referenced above not apply to the DGen rate class in this rate application?

b) Please provide an alternate rate design for 2020 and 2021 where DGen is moved to a minimum ratio of 90%.

c) What is Hydro One's view on the applicability of the Decision referenced above on the revenue to cost ratio ranges for the acquired rate classes?

OEB staff I51-249
Ref: Exhibit H1/Tab1/Schedule 1, pp 9-14
On Table 6, several of the R/C ratios are different between 2018, and 2019 Before Rate Design. In the case of DGen, this is material as the R/C ratio has changed from 0.63 to 0.68.

Please provide a schedule which includes the derivation of the R/C ratios before and after rate design in 2019, 2020, and 2022.

Issue 52. Are the proposed fixed and variable charges for all rate classes over the 2018-2022 period, appropriate, including implementation of the OEB's residential rate design?

OEB staff I52-250
Ref: Exhibit H1/Tab1/Schedule 1, p 2, Exhibit H1/Tab2/Schedule 2, p 9
Exhibit H1/Tab4/Schedule 1, p 2
Hydro One's existing DGen rates are $149.34 fixed, $7.0504 variable. For 2018 it proposes to increase the fixed charge to $196.16 and decrease the variable charge to $6.4310. From 2019 to 2022, it proposes to increase the revenue to cost ratio for this class while holding the fixed charge constant by increasing the variable charge to $12.1690 in 2022. It is noted that the bill impact for the low consumption level has a total bill impact over 15% in 2018, and the high consumption level has a total bill impact over 22% in 2019.

a) Please explain why Hydro One is proposing to decrease the variable charge in 2018 only to significantly increase it in 2019-2022.

b) Please provide an alternate rate design where the fixed proportion of revenue is maintained in 2018, and until the fixed charge reaches $196.16 – using a fixed charge of $196.16 from that point forward.

Issue 53. Are the proposed Retail Transmission Service Rates appropriate?

Issue 54. Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?

OEB staff I54-251
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, pp 23-24
Hydro One states that "Emergencies related to safety or reliability will not be billed at the higher after regular hours rates."

a) Please confirm that Hydro One still intends to bill emergencies at the regular hours rates.

b) How does Hydro One intend to recover the full costs of these services where the service charge is insufficient?

OEB staff I54-252
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 25
Hydro One states that "the winter months in which this study were run were abnormally warm and calm."

a) Does Hydro One intend to repeat this study on a regular interval? If so, how frequently?

b) Can Hydro One provide an estimate of how much would it cost to repeat this study?

OEB staff I54-253
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1
When Hydro One performs a service, it is conceivable that additional related activities may follow. For example, a call to the call centre may follow a disconnection.

a) Has Hydro One considered scenarios where a service routinely generates an expected amount of follow-up activity?

b) If so, is this included in the service charge?

OEB staff I54-254
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 27
Hydro One states that the service charge "fees are not relevant in the context of a typical customers' total bill and therefore a mitigation or phase in concept should not apply."

a) Are there any groups of customers where an individual customer is likely to make routine use of services?

b) From the perspective of a customer requiring routine use of services, please explain why the services would not be considered part of their total bill?

OEB staff I54-255
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 68
Ref: Exhibit E1/Tab1/Schedule 2, pp 5-8
Charges 41 and 42 relate conversion to central metering.

a) Has Hydro One performed either of these services in the years 2014-2017?

b) Does Hydro One anticipate performing these services in the years 2018-2022?

c) If the answer to part a) or part b) is yes, please explain how it is included in External Revenues given that it is missing from Table 4 at the second reference.

d) If the answer to a) is no, please explain how Hydro One determined the hours required to perform the tasks.

OEB staff I54-256
Ref: Exhibit H1/Tab2/Schedule 3, p 74
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 67
For service 41, in the first reference, 6.06 hours of Field Staff (RLM) time is required. At the second reference, 6.06 hours of inside staff time is required. At the third reference, 6.06 hours of RLM time is required.

a) Please reconcile.
b) Please explain the activities required in the 6.06 hours, and how this differs from the 3.5 hours of Field Staff (ADET) time required.

OEB staff I54-257
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 42
Service 16 is charged when an employee collects in the field due to non-payment of a bill.

Please confirm that service 16 is applied when an employee arrives to perform a disconnection or installation of a load limiting device.

OEB staff I54-258
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, pp 40 and 96
Service 14 requires 0.3 hours of clerical (call centre) staff time. This time is charged at a rate of $74.70, and a payroll burden rate of 59.30% is applied.

a) Please advise what is included in the $74.70/hr rate for a call centre employee.
b) Please advise what is included in the payroll burden rate.

OEB staff I54-259
Ref: Exhibit H1/Tab2/Schedule 3, p 19
Ref: Exhibit H1/Tab2/Schedule 3, Attachment 1, p 96
The payroll burden rate is 59.30% in the section reference, and in the first reference it increases from 53.60% to 55.60%.

a) Please advise what is included in the payroll burden rate at each reference.
b) Please explain why the payroll burden rate is increasing over time at the second reference.

OEB staff I54-260
Ref: Exhibit H1/Tab2/Schedule 3, pp 103-105
Table 3 details how the telecom rate is calculated for 2017. Total capital costs of a pole of $124.34 are derived, and an allocated capital cost associated with telecom of $42.65 is provided. With non-capital costs, the total cost is $46.75 per pole.

a) Please confirm that all the figures on table 3, with the exception of the net embedded cost are annual amounts.

b) Please provide a derivation of the allocated capital cost of $42.65.

c) Please clarify if service 30, access to power poles is a monthly or annual charge.

OEB staff I54-261
Ref: Exhibit H1/Tab2/Schedule 3, p 8
Charge 49 relates to street light use utility poles.

a) Please provide a derivation of the $2.04 charge for municipal streetlight access to poles, and explain where costs are incurred monthly vs. annually.

b) Please clarify if service 49 is a monthly or annual charge.

Issue 55. Are the proposed line losses over the 2018 – 2022 period appropriate?

Issue 56. Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?

OEB staff I56-262
Ref: Exhibit G1/Tab2/Schedule 1, p 5
Norfolk and Haldimand have existing Embedded Distributor rate classes.

a) Please identify the embedded distributors, and whether they will continue to be embedded distributors of Hydro One.

b) If there will continue to be embedded Norfolk and Haldimand distributors, please advise which rate class they would join in 2021.

OEB staff I56-263
Density of Acquired Rate Classes
Ref: Exhibit G1/Tab2/Schedule 1, p 6 and Exhibit G1/Tab3/Schedule 1, pp 4 and 5
From the reference in Tab 2, "The decision to create two new sets of acquired rate classes is based on the fact that the majority of former Woodstock Hydro customers are located in urban areas, with an average customer density of 63 customers/cct-km, while customers from former Norfolk Power and Haldimand Hydro have a mixed density."

From the reference in Tab 3/Schedule1/page 5 "Hydro One is proposing to use a density factor of '1' for all acquired rate classes as these classes are not distinguished based on density." It is noted that at page 4 of the second reference, Hydro One has selected that the AR Weighting Factor for Services be set to 0.75, mirroring the R1 rate class, while the AUR class Weighting Factor for Services be set to 0.5, mirroring the UR rate class.

a) Please explain whether density is a distinguishing characteristic of the two sets of new rate classes.

b) If not, please explain why "two sets of acquired rate classes" are necessary.

c) If so, please provide details supporting a density factor of "1" for all acquired rate classes, or propose density factors reflective of differences in density.

OEB staff I56-264
Escalated Acquired Utility Rates
Ref: Exhibit Q/Tab1/Schedule 1, pp 20-25
Hydro One, in its update, has provided comparisons to Escalated Acquired Utility rates.

a) Please provide a derivation of the escalated 2021 rates.
b) Please provide a derivation of the escalated 2022 rates.

OEB staff I56-265
Depreciation Cost Adjustment
Ref: Exhibit G1/Tab2/Schedule 1, p 4

Hydro One states “The proposed acquired classes would also be used to harmonize the rates of any future acquired utilities.”

a) How does Hydro One intend to handle the situation where a new acquired utility may have substantially different costs from the existing acquired utilities?

   i. Would the new acquired utility’s rates be quickly harmonized with the existing acquired utilities?
   ii. How would the rates charged to the customers of each acquired utility reflect the costs to serve those customers?
   iii. Would additional rate classes be required?

b) Does Hydro One plan to eventually harmonize rates for acquired utilities with the rates for the legacy customer base?

   i. If so, how?
   ii. If so, would Hydro One require acquired rate classes of different stages in harmonization to facilitate a smooth transition to harmonized rates?
   iii. If not, how does Hydro One plan to ensure that the costs to serve the acquired utilities’ customers continues to be updated and reflected in future rate applications?

J. DEFERRAL/VARIANCE ACCOUNTS

Issue 57. Are the proposed amounts, disposition and continuance of Hydro One’s existing deferral and variance accounts appropriate?

OEB staff J57-266
Ref: Exhibit F1/Tab1/Schedule 1, Attachment 1

a) Please provide a table that compares the December 31, 2016 closing balances for each account presented in the DVA continuity schedule to the corresponding December 31, 2016 account balance as filed by Hydro One in its RRR filing for 2016.

b) Please provide explanations for any differences. If there are no differences, Hydro One may just respond by providing a statement that confirms that their 2016 balances per the DVA continuity schedule in Exhibit F1-1-1, Attachment 1 agree to their 2016 RRR filing, without exception.

OEB staff J57-267
Ref: Exhibit F1/Tab1/Schedule 1
Section 2.5.9.1 in Chapter 2 of *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications* requires all distributors to complete a GA Analysis Workform in order to support the reasonability of its balance in account 1589.

a) In accordance with the filing requirements, please complete and submit the GA Analysis Workform. Please note that a separate GA Analysis Workform must be completed for each year since the year that account 1589 was last disposed.

b) Section 2.5.9.1 also requires a certification by the CEO, CFO, or equivalent, confirming that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed. Please provide this certification.

OEB staff J57-268
Ref: Exhibit F1/Tab1/Schedule 1
In booking expense journal entries for Charge Type 1142 (formerly 142), and Charge Type 148 from the IESO invoice, please confirm which of the following approaches is used:

a) Charge Type 1142 is booked into Account 1588. Charge Type 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589, respectively[1].

b) Charge Type 1142 is booked into Account 1588. In relation to Charge Type 148, the non-RPP quantities multiplied by the GA rate is booked to account 1589 and the remainder of Charge Type 148 is booked to account 1588.

c) Charge Type 148 is booked into Account 1589. The portion of Charge Type 1142 equaling RPP-HOEP for RPP consumption is booked into Account 1588. The portion of Charge Type 1142 equaling GA RPP is credited into Account 1589.

d) If another approach is used, please explain in detail.

[1] Note, the following in all references in OEB Staff questions relating to amounts booked to accounts 1588 and 1589. Amounts are not booked directly to accounts USoA 1588 and 1589 relating to power purchase and sale transactions, but are rather booked to the cost of power USoA 4705 Power Purchased/4707 Charges - Global Adjustment and the respective Energy Sales USoA accounts, respectively. However, accounts 1588 and 1589 are impacted the same way as accounts 4705/4707 are for cost of power transactions, and the same way as the Energy Sales accounts are for revenue transactions.

OEB staff J57-269
Ref: Exhibit F1/Tab1/Schedule 1
With regard to the amount recorded in USoA 1589 at December 31, 2016, all components that flow into Account 1589 (i to iv in table below) should be based on actuals in the DVA continuity schedule. Please complete the following table to:

a) Indicate whether each of the components are based on estimates or actuals at year end, and

b) Quantify the adjustment amount pertaining to each component that is trued-up from estimate to actual.

	Component	Estimate or Actual	Notes/Comments	Quantify True Up Adjustment $ Amount
i	Revenue (i.e. is an unbilled revenue true-up adjustment reflected in the balances being requested for disposition?)			
ii	Expenses - GA non-RPP: Charge Type 148 with respect to the quantum dollar amount (i.e. is expense based on IESO invoice at year end)			
iii	Expenses - GA non-RPP: Charge Type 148 with respect to the RPP/non-RPP kWh volume proportions.			
iv	Credit of GA RPP: Charge Type 142 if the approach under Staff Question 1c is used			

c) For each item in the table above, please confirm that the GA Analysis Workform for 2016 and the DVA Continuity Schedule for 2016 have been adjusted for settlement true-ups where settlement was originally based on estimate and trued up to actuals subsequent to 2016.

OEB staff J57-270
Ref: Exhibit F1/Tab1/Schedule 1
With regard to the disposition of account 1589, Hydro One has indicated that it will be receiving a GA refund from the IESO of $121.8 million due to errors in meter readings for the period from January 2005 through to August 2016. Since the expected GA refund from the IESO is greater than the December 31, 2016 balance in account 1589 (117.9 million), the applicant is not proposing to seek disposition of account 1589 as part of this proceeding.

a) The applicant expected to receive the refund monthly during the period April through November 2017. Please confirm that these amounts have now been received and provide the actual dollar amount that was recovered.

b) Does the issue that gave rise to the refund only impact account 1589 or are other DVA accounts also impacted as a result. Please explain.

c) Was the refund allocated entirely to Hydro One Distribution? If not, please provide the amount of the total refund that relates to Hydro One Distribution.

d) How much of the recovery from the IESO was allocated to account 1588 relating to RPP customers and how much was allocated to account 1589 relating to non-RPP customers?

   i. How was the portion that was allocated to account 1588 for RPP customers settled with the IESO.
   ii. If no portion of or the recovery from the IESO was allocated to account 1588 for RPP customers, please explain why.

e) As the amounts have been fully recovered from the IESO, utilizing the adjustments column of the DVA Continuity Schedule please adjust the relevant account balances of December 2016 to reflect the impact of this recovery from the IESO.

OEB staff J57-271
Ref: Exhibit F1/Tab1/Schedule 1

With regard to the USoA account 1588 balance as at December 31, 2016, all components that flow into Account 1588 (i to iv in table below) should be based on actuals at year end. Please complete the following table to:

a) Indicate whether each of the below components is based on estimates or actuals at year end, and

b) Quantify the adjustment pertaining to each component that requires a true-up from estimate to actual

	Component	**Estimate or Actual?**	**Notes/Comments**	**Quantify True Up Adjustment $ Amount**
i	Revenues (i.e. is an unbilled revenue true-up adjustment reflected in the balances being requested for disposition?)			
ii	Expenses – Commodity: Charge Type 101 (i.e. is expense based on IESO invoice at year end)			
ijj	Expenses - GA RPP: Charge Type 148 with respect to the quantum dollar amount (i.e. is expense based on IESO invoice at year end)			

iv	Expenses - GA RPP: Charge Type 148 with respect to the RPP/non-RPP kWh volume proportions.			
v	RPP Settlement: Charge Type 142 including any data used for determining the RPP/HOEP/RPP GA components of the charge type			

c) For each item in the table above, please confirm that the DVA Continuity Schedule for 2016 has been adjusted for settlement true-ups where settlement was originally based on estimate and trued up to actuals subsequent to 2016.

OEB staff J57-272
Ref: Exhibit F1/Tab1/Schedule 1

Hydro One is proposing to dispose of several sub-accounts of account 1508:

a) Pension Cost Differential Account – Since the last disposition of this account balance, please provide a table that compares on an annual basis the pension amount approved in rates and the actual pension contributions made, with the total of this table agreeing to the December 31, 2016 balance being sought for disposition. For each of the years, please provide support for the actual contributions made including how the applicant has performed the allocation between capital and non-capital in respect to these actual contributions.

b) Distribution System Code Exemption Deferral Account – Since the last disposition of this account, please provide a table that summarizes by year, and by cost category (as approved by the OEB), the amounts incurred in each year up to December 31, 2016. Provide explanations of the costs included in each category along with other relevant evidence to support the balance. .

c) OEB Cost Differential Account – Please provide the calculation to support the balance in the account at December 31, 2016.

d) Bill Impact Mitigation Variance Account – please provide a table that summarizes, by year, the costs that have been included in this account.

e) Please provide the relevant accounting orders for each of the accounts above.

OEB staff J57-273
Ref: Exhibit F1/Tab1/Schedule 1
For all draft accounting orders, the accounting orders themselves should be stand-alone in that they contain sufficient detail necessary for the reader to understand the purpose and functionality of the account. Currently several of the draft accounting orders state “as documented in section XX of the application” in lieu of providing the required detail.

Please update accordingly.

Issue 58. Are the proposed new deferral and variance accounts appropriate?

OEB staff J58-274
Ref: Exhibit F1/Tab1/Schedule 1

Hydro One has proposed to create a new variance account to capture the difference between the revenue requirement associated with actual in-service additions and the revenue requirement associated with the OEB approved in-service capital additions, on a cumulative basis. From the description provided in the accounting order and related evidence filed in the application, it is not clear if this variance account will also capture the impact on the test period revenue requirement from a short-fall in the bridge year (2017) in-service additions.

a) Will the test period revenue requirement impact of a shortfall in the in-service additions for the bridge year be captured in this variance account?

b) If the response above is no, please explain why.

c) The accounting order should clearly specify the period over which the revenue requirement impact will be captured, please update the accounting order accordingly.

Issue 59. Is the proposal to discontinue several deferral and variance accounts appropriate?

-end-