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BY E-MAIL

August 3, 2018

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Hydro One Networks Inc.
Application for Rates
OEB File Number EB-2017-0049

Please find attached OEB staff's submission on the application filed by Hydro One Networks Inc.

Original Signed By

Martin Davies
Project Advisor, Rates
Major Applications

2018 - 2022 ELECTRICITY DISTRIBUTION RATES

Hydro One Networks Inc.

EB-2017-0049

ONTARIO ENERGY BOARD

STAFF SUBMISSION

August 3, 2018

INTRODUCTION

Hydro One Networks Inc. (Hydro One) filed a five-year Custom Incentive Regulation (Custom IR) application with the Ontario Energy Board (OEB) on March 31, 2017 with subsequent updates under section 78 of the *Ontario Energy Board Act, 1998*[1], seeking approval for changes to its distribution rates, to be effective January 1, 2018 to December 31, 2022 (the application).

Hydro One is applying for an Order approving its distribution revenue requirement, cost allocation and rates as determined by its Custom IR approach for the period 2018 to 2022 as discussed below.

This submission reflects observations and concerns which have arisen from OEB staff's review of the record of this proceeding and are intended to assist the OEB in evaluating the application and in setting just and reasonable rates.

SUMMARY OF THE APPLICATION

Hydro One has applied for the following:

- A requested 2018 revenue requirement which reflects an increase of 3.5% over 2017 OEB-approved levels. The increase is largely attributed to rate base growth including associated increases in depreciation, return on capital and income tax expenses, partially offset by a lower cost of debt and lower operating, maintenance and administration (OM&A) expenses. After adjustment for a 3.0% reduction in load forecast, the resulting average impact on distribution rates is an increase of 6.5% in 2018 and an average of 3.4% per annum over the term of the application.
- Bill impacts for typical residential and general service customers are stated as follows:[2]

[1] S.O. 1998, c.15 (Schedule B)
[2] Exh. H1, Tab 4, Sch 1, p. 4.

Rate Class	Monthly Consumption	Dx Bill		Total Bill	
	(kWh)	$	%	$	%
Medium Density Residential Customer (R1)	750	2.47	4.8	4.40	2.9
General Service Energy Customer (GSe)	2,000	6.40	4.5	7.80	1.8

Hydro One stated that updated distribution rates would be addressed through the draft rate order process.

- A Custom Incentive Rate-Setting approach for the five-year period of the application. The revenue requirement for 2018, which is the first year, is determined using a cost of service forward test year approach. The revenue requirements for the remaining years of 2019 to 2022 are proposed to be established through a Revenue Cap IR, whereby the revenue for the test year t+1 is equal to the revenue in year t adjusted annually by the revenue cap index (RCI).

- A level of capital investment represented as required to avoid degradation in overall system asset condition, to meet regulatory requirements and maintain current reliability levels in response to customer concerns about rising rates. The requested 2018 capital portion of the revenue requirement is 2.7% above the 2017 OEB-approved level as a component of overall revenue requirement.

- Requested OM&A expenses of $576.7 million (2.7% below 2017 OEB-approved OM&A costs) represented as reflecting efficiency improvements and cost reductions to control OM&A contribution to higher rates.

- An earnings sharing mechanism (ESM) that will permit customers to share 50% of any earnings exceeding the regulatory return on equity (ROE) by more than 100 basis points in any year of the five year term.

- Integration of three acquired utilities (Norfolk Power Distribution Inc. (Norfolk), Haldimand County Hydro Inc. (Haldimand) and Woodstock Hydro Services Inc. (Woodstock) (collectively the Acquired Utilities) effective January 1, 2021.

OVERVIEW OF OEB STAFF'S SUBMISSION

This submission is organized based on the OEB approved Issues List.

The following is a summary of OEB staff's main submissions. The impacts on Hydro One's proposed revenue requirement of these submissions are summarized in the following table:[3]

$ millions

Hydro One 2018 Revenue Requirement	**1475.5**
Proposed OM&A Reduction - Non Pension Related	-17.0
Proposed OM&A Reduction - Pension Related	-17.0
Proposed Capital Reduction - Pension Related	-2.0
Proposed Capital Reduction - Capital Program	-6.9
Non-capitalization of OPEB Costs	11.7
Specific Service Charges Reduction	-1.6
Revised Hydro One 2018 Revenue Requirement	**1442.7**
Overall $ Reduction	32.8
Overall % Reduction	2.23

- OEB staff does not support all elements of Hydro One's application and is proposing an overall 2% reduction in the 2018 test year revenue requirement. That said, on their face, the rate impacts are supported by the evidence, subject to adjustments proposed by OEB staff, and in a few cases where mitigation is proposed, the planned mitigation is reasonable. Hydro One stated that its applied-for revenue requirement would result in a 6.5% distribution rate increase in 2018 over the 2017 OEB-approved level. Hydro One further stated that the average increase over the proposed five-year period is 3.4% per annum. OEB staff notes that, as shown above, the rate increases in 2018 for a typical residential customer are expected to be significantly lower than 6.5% - 4.8% on the distribution bill and 2.9% on the total bill. These impacts are before the effects of the proposed OEB staff reductions are taken into account.

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[3] Argument-in-chief, p. 19, Table 1 for Hydro One's 2018 revenue requirement. Capital reductions have been effected through an assumed 10% first year effect on revenue requirement. The basis for the specific decreases proposed are discussed in the relevant sections of the submission. This table also excludes the impacts related to the refund Hydro One received from the IESO related to the Global Adjustment which is discussed in the deferral account section of this submission.

- Customer engagement was generally adequate, subject to some specific concerns in the area of the Distribution System Plan (DSP).)

- Agreement with Power Systems Engineering's (PSE) proposed 0.45% stretch factor and overall acceptance of the proposed Custom IR framework subject to some specific concerns expressed.

- General acceptance of Hydro One's approach to the integration of the Acquired Utilities with some specific concerns about what would be included in the proposed update at the time of integration in 2021.

- Scorecards provided by Hydro One and the targets and performance levels tied into these scorecards do not provide Hydro One with adequate incentive during the 2018-2022 period to achieve outcomes for existing and future customers that appropriately reflect customer expectations as many of the targets are either not stated, or do not appear challenging given the present level of achievement.

- Productivity gain forecasting of combined capital and OM&A of $398 million over five years appears to be overly optimistic due to a lack of clarity as to how the stated productivity gains are distinct from normal prudent cost management. It is also not clear that where headcount reductions are concerned, that they reduce Hydro One's overall headcount, as compared to a reduction that may take place in one part of the organization but be offset by an increase in another part.

- Rates should be set on the basis of a 11% per annum reduction in Hydro One's proposed $3.6 billion 2018 to 2022 capital program or approximately $400 million in total on the basis of concerns identified by OEB staff that justify a 17% reduction in the level of system renewal costs, which translates into a reduction of approximately 8% in the overall capital budget. OEB staff believes that in addition to its specific concerns about overspending in this area, there are other factors more difficult to quantify that would justify a further cut, particularly related to: the impact of the new vegetation management program which given it is in its very early stages of implementation is hard to estimate but is likely to have some impact;. OEB staff also has concerns that Hydro One's claimed level of productivity savings of $398 million may be overstated;, as well as with the limited extent of the scoping information provided by Hydro One on many projects and the lack of clarity in terms of how it prioritizes projects and determines which ones are selected for implementation, particularly in the context of the concerns expressed by the Auditor General.

- A minimum level of reduction in Hydro One's proposed 2018 OM&A level of $17 million (from $577 million proposed to $560 million) should be made. Hydro One's consistent underspending of its forecasts justifies this and suggests that there may be room for an additional OM&A cut beyond this level, given the significant level of increase in Hydro One's non-executive compensation costs forecast in 2018. OEB staff is also recommending an additional OM& cut related to pension fund contributions which is discussed below

- Executive compensation is specifically excluded from the Issues List and is also precluded from inclusion as a result of the *Urgent Priorities Act, 2018*, so staff has made no submissions in this area. Hydro One is forecasting an almost 10% increase in distribution non-executive compensation costs in the 2018 test year when compared to the 2017 actual. OEB staff considers this increase to be excessive given currently expected increases in the inflation rate, and is a further basis for the overall reduction in the test year OM&A being recommended by OEB staff. In terms of comparators, Hydro One remains 12% over the median in 2017 which is an improvement over the 2016 level of 14%, but worse than the 10% level of 2013.

- The proposed pension fund contributions should not be allowed in rates given that the actuarial valuation provided by Hydro One indicates that no employer contributions are presently required as the fund is in a significant surplus position. This results in an additional $17 million proposed reduction in OM&A and $20 million in capital.

- OEB staff have no major concerns with load forecast, cost allocation or rate design, other than specific service charges.

- Specific service charge increases that are significant should not be approved unless customers have been adequately engaged. If necessary, large impacts should be mitigated through phased-in increases should be approved, but cost causality should be respected. On this basis, OEB staff is recommending a $1.6 million reduction in the revenue requirement.

- Deferral and Variance accounts proposed clearance is established consistent with OEB requirements (Accounting Procedures Handbook, subsequent OEB direction) with one exception. Disposition sought for an amount of $8.3 million owing from customers over a one-year recovery period does not include adjustment to GA account 1589 for IESO credit, which should be incorporated.

- Hydro One requested a new OPEB deferral account due to a change in the US GAAP accounting standard for pension and OPEB costs. Certain components of OPEBs that were previously permitted to be capitalized to assets must now be expensed to OM&A. Hydro One proposed a deferral account to capture the impact in order to avoid adverse rate impacts to customers. Hydro One also clarified that its preference is to get OEB approval to continue to capitalize these amounts for regulatory purposes, or failing that, for the OEB to approve the deferral account. OEB staff is opposed to both the account proposal and the continued capitalization of the costs. The impact of OEB staff's proposal is a net $11.7 million in crease in the 2018 revenue requirement due to the reduced capitalization levels.

A: GENERAL

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

Background

Hydro One provided in its evidence the table below[4] which lists OEB directions to Hydro One in its previous distribution rates decision[5] and the evidentiary references in the current application that respond to them. Hydro One stated that there were no other outstanding OEB directives or undertakings from prior proceedings that are relevant to the application.

[4] Application, Exh A, Tab 2, Sch 2, p. 1, Table 1 Filed: 2017-03-31
[5] EB-2013-0416

#	OEB Direction	Exhibit Reference
1	File a total factor productivity study of Hydro One's own productivity, including data from 2002 and following years at a minimum.	Exhibit A, Tab 3, Schedule 2
2	File a compensation study similar to the study Hydro One filed in EB-2013-0416 to allow benchmarking to comparable companies.	Exhibit C1, Tab 2, Schedule 1
3	File a comprehensive trend analysis of the vegetation management program showing year over year comparisons in unit costs.	Exhibit B1, Tab 1, Schedule 1
4	File a best practices study, if undertaken, for vegetation management similar to the CN Utility study filed in EB-2009-0096.	Exhibit B1, Tab 1, Schedule 1
5	File an updated depreciation study.	Exhibit C1, Tab 6, Schedule 1
6	File a consolidated Distribution System Plan, with either an independent third-party review of the Plan if conducted, or an explanation of the decision not to conduct such a review.	Exhibit B1, Tab 1, Schedule 1
7	File annual capital in-service additions, with explanations of any variance from approved levels (as required by the OEB Filing Requirements).	Exhibit D1, Tab 1, Schedule 2
8	File an external benchmarking study on the unit cost of the pole replacement program.	Exhibit B1, Tab 1, Schedule 1
9	File an internal trend analysis to show the variability of the unit costs of the pole replacement program year over year.	Exhibit B1, Tab 1, Schedule 1
10	File an external benchmarking study on the unit cost of the station refurbishment program.	Exhibit B1, Tab 1, Schedule 1
11	File an internal trend analysis to show the variability of the unit costs of the station refurbishment program year over year.	Exhibit B1, Tab 1, Schedule 1
12	Report on an updated customer classification review.	Exhibit G1, Tab 2, Schedule 1
13	File a study on Hydro One's miscellaneous service charges, assessing whether the charges reflect underlying costs.	Attachment 1 to Exhibit H1, Tab 2, Schedule 3.

OEB Staff Submission

OEB staff submits that Hydro One has responded appropriately to all relevant directions from previous proceedings, subject to any concerns OEB staff may express about the contents of the above reports in subsequent sections of this submission.

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

Background

OEB staff notes that the OEB hosted a series of community meetings regarding the application across the province (including a province-wide telemeeting) as listed below.[6]

June 15, 2017	Leamington, Ontario	Leamington Kinsmen Recreational Complex
June 19, 2017	Napanee, Ontario	Strathcona Paper Centre
June 20, 2017	Rockland (Ottawa), Ontario	Club Powers, Colombian Hall
June 21, 2017	Owen Sound, Ontario	Harry Lumley Bayshore Community Centre
June 22, 2017	Ancaster, Ontario	Ancaster Rotary Centre
June 26, 2017	Stouffville, Ontario	Royal Canadian Legion – Branch 459
June 27, 2017	Dryden, Ontario	Legion Hall
June 28, 2017	Sudbury, Ontario	Rotary Centre
July 12, 2017	Telemeeting	Province-wide
July 13, 2017	Bracebridge, Ontario	Bracebridge Sportsplex

The OEB staff summary of the community meetings identified three major areas of concern among the attendees:

- The cost of electricity was too high and therefore Hydro One's request for a rate increase should not be approved
- Salaries at Hydro One are too high
- Reliability and service capacity issues[7]

OEB Staff Submission

OEB staff will address the extent to which it believes Hydro One has adequately responded to the customer concerns expressed in the Community Meetings held for this application in its submissions on the relevant issues related to these concerns.

The first major concern of consumers was that the cost of electricity was too high and therefore Hydro One's request for a rate increase should not be approved. OEB staff has

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[6] EB-2017-0049 "OEB Staff Summary of Community Meetings Hydro One Networks Inc. Application for 2018-2022 Distribution Rates," September 7, 2017, p. 1

[7] *Ibid,* p. 12

responded to this concern by conducting a thorough review of Hydro One's proposals that are leading to the proposed increase and recommending reductions in such key areas as OM&A expenses (discussed in section F) and the capital program (discussed in section D). The effect of OEB staff's recommendations is to reduce the size of the rate increase requested by Hydro One.

The second major concern was that salaries at Hydro One are too high. OEB staff shares this concerns and discusses the reasons for this under Issue 40. OEB staff is recommending a $17 million reduction in Hydro One's requested increase in OM&A expenses in part because of its concerns that Hydro One's compensation costs are too high.

The third major concern was with reliability and service capacity concerns. OEB staff has discussed this matter in a number of areas of the application, particularly under Issue 24 and has attempted to achieve a balance in its recommendations between the concerns customers have expressed about the cost of electricity with the need to also respond to their concerns about reliability and service capacity.

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

Background

Hydro One stated that it follows standard regulatory practice and has calculated its revenue requirement consistent with the principles of the OEB's *2006 Electricity Distribution Rate Handbook*. Hydro One provided a comparison of the 2017 revenue requirement proposed in the previous distribution rates application[8], along with the revenue requirement proposed for the 2018 test year in the current application as shown below[9]:

[8] EB-2013-0416

[9] Argument-in-chief of Hydro One Networks Inc., July 20, 2018, p. 20.

$ millions

Description	2017 OEB Approved	2018 Forecast	2018 vs. 2017 Change (%)
OM&A	593.0	576.7	(1.1)
Depreciation and Amortization	390.2	398.2	0.6
Income Taxes	48.7	65.2	1.2
Return on Capital	435.8	474.0	2.7
Total Revenue Requirement	**1,467.6**	**1,514.2**	**3.3**
Deduct External Revenues and Other	(52.7)	(47.0)*	0.4
Rates Revenue Requirement	**1,414.9**	**1,467.2**	**3.7**
Regulatory Deferral and Variance Accounts Disposition	11.1	8.3**	(0.2)
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,475.5**	**3.5**

* 2018 External Revenue was updated as part of J11.02.

** Regulatory Deferral and Variance Accounts Disposition is updated to reflect Hydro One's revised proposal.

Hydro One stated that its proposed 2018 revenue requirement is the amount it requires to achieve its business objectives and to align customer needs and preferences, responsible stewardship of a safe and reliable system and impact on rates. Furthermore, it is a reflection of Hydro One's commitment to pursuing efficiencies and improved productivity before requesting its customers pay more.

The revenue requirements for the remaining years of 2019 to 2022 are proposed to be established through a Revenue Cap IR, whereby the revenue for the test year t+1 is equal to the revenue in year t adjusted annually by the RCI.

OEB Staff Submission

OEB staff does not support all elements of Hydro One's application and is proposing an overall 2% reduction in the 2018 test year revenue requirement. OEB staff submits that the overall increases in the distribution revenue requirement from 2018 to 2022 proposed by Hydro One are supported by the evidence, subject to adjustments proposed by OEB staff, as discussed in the relevant sections of this submission.

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

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?**

Background

Hydro One stated that its applied-for-revenue requirement would result in a 3.5% distribution rate increase in 2018 over 2017 OEB-approved levels and that it further seeks an additional 3% increase in rates in 2018 due to declines in load which are beyond its control. Hydro One further stated that the average increase over the proposed five-year period is 3.4% per annum and that these revised rate impacts reflect a 0.3% per annum reduction from the original filing in March 2017.[10]

Hydro One stated that the total bill impacts across most rate classes resulting from the revenue requirement, regulatory asset disposition and rate harmonization requested in the application are below 10%.

However, Hydro One stated that it has proposed a rate mitigation plan for the following three classes of customers of recently acquired utilities (the Acquired Utilities): (i) street lighting customers, (ii) sentinel light customers and; (iii) unmetered scattered load (USL) customers. Hydro One proposed rate mitigation in the form of a bill credit for those customers within these rate classes that are experiencing rate increases to ensure that they will not experience total bill impacts greater than the mitigation threshold.

Hydro One also proposed rate mitigation in the form of adjustments to the revenue-to-cost ratios for the DGen customer class to limit total bill impacts to no more than 10% for a typical customer in that class.

OEB Staff Submission

OEB staff submits that the mitigation measures proposed by Hydro One for its distributed generation customers in 2018 and 2019 are appropriate. With respect to the issues related to rate mitigation for customers of the Acquired Utilities, please see the OEB staff submissions under issue #14.

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[10] Argument-in-chief, p. 22

OEB staff considers the bill impacts for the remaining customer classes as supported by the evidence, subject to adjustments proposed by OEB staff, as discussed in the relevant sections of this submission.

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?

Background

Hydro One stated that it is committed to developing and maintaining positive relationships with First Nations and Métis communities and customers across Ontario. Hydro One further stated that it recognizes the unique rights and interests of Aboriginal peoples in Canada and seeks to work with First Nations and Métis communities in Ontario in the spirit of collaboration, mutual respect and trust and shared responsibility.

Hydro One noted that it provides electricity transmission and distribution services to 85 First Nations communities. Furthermore, approximately 21,700 First Nations customers residing on reserve lands receive service, 88% of which are residential and 12% are general service customers. Transmission and distribution facilities used to provide this service are situated across reserve lands, traditional or treaty lands.

Hydro One stated that the three pillars of its First Nations and Métis Relations Strategy Framework are as follows:

> a) Integration - Improve communication with First Nation and Métis communities and develop programs to ensure their unique interests and concerns are integrated into Hydro One's lines of business and that Hydro One works with communities in a way that recognizes and respects Aboriginal and treaty rights.
>
> b) Partnership - Develop opportunities to collaborate with First Nations and Métis communities in Ontario through the development of business, technical, knowledge, and advocacy partnerships.
>
> c) Leadership - Provide opportunities to First Nations and Métis individuals within Hydro One's organization to support the training, development, and promotion of First Nations and Métis employees and future leaders.

Hydro One stated that it is continuing to research and consider industry best practices to benchmark its activities in these three areas and will seek input on and give consideration to new strategic approaches to achieve these objectives.[11]

Hydro One stated that over the past 18 to 24 months, it has refined its approach as to how it engages with First Nations and Métis communities and that its strategy addresses the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service as evidenced by: (1) Hydro One's engagement with its First Nations and Métis customers; and (2) Hydro One's initiatives that address concerns expressed by First Nations and Métis customers.[12]

During the oral hearing phase of the proceeding, it was announced that Hydro One and Anwaatin Inc. (Anwaatin) had agreed on a settlement proposal to be presented to the OEB with respect to Anwaatin's motion to review and vary the OEB's recent Hydro One transmission decision.[13]

Hydro One submitted that the agreement with Anwaatin is a significant achievement as not only is the pilot project intended to address reliability concerns in Anwaatin First Nations Communities, but it is also intended to assess whether similar and repeatable approaches may be used in other remote areas of the Hydro One distribution system that are experiencing poor reliability conditions. Hydro One stated that the maximum total cost of the Anwaatin initiative is $5 million and any further funding is dependent on the results of the pilot project and approval of increases to Hydro One's capital envelope.[14]

OEB staff asked Anwaatin by way of undertaking[15] with reference to the settlement proposal to: (1) discuss what impact, if any, Anwaatin believes the filing of the settlement proposal would have on this proceeding; and (2) to state what Anwaatin is requesting that the OEB direct Hydro One to do in its decision on the application.

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[11] Exh A, Tab 4, Sch. 2, pp. 1-2
[12] Argument-in-chief, p. 25
[13] Exhibit K4.4 EB-2017-0335 "Settlement Proposal Anwaatin Inc. Motion to Review and Vary the Ontario Energy Board's Decision on Hydro One Network Inc.'s Transmission Rates in EB-2016-0160," June 15, 2018
[14] Argument-in-chief, p. 28.
[15] J11.4 Filed: July 17, 2018.

Anwaatin's response to this undertaking was that Anwaatin would generally request that the OEB do the following:[16]

- Make findings related to reliability in Indigenous communities that are supported by evidence;
- Incorporate, by express reference in its decision and potentially future scorecards, the distributed energy resources reflected in Pilot Project and the communications and cooperation plan reflected in the settlement proposal as innovative non-wires approaches to attempt to address the reliability challenges and the disparate impact of those challenges in Indigenous communities; and
- Approve the portion of HONI's proposed capital investment envelope, any applicable O&M amounts, and related evidence pertaining to the settlement proposal and the Pilot Project.

OEB Staff Submission

OEB staff commends Hydro One for its development of its First Nations and Métis Relations Strategy Framework and believes that the OEB should encourage both Hydro One and First Nations and Métis groups to continue this evolution to achieve greater understanding of the concerns of both sides.

OEB staff submits that the ability of the two sides to reach a settlement proposal is a strong indicator that Hydro One's First Nations and Métis Relations Strategy Framework is having a positive influence in improving relations between the two sides.

OEB staff supports the settlement proposal and notes that as the pilot project (for which Hydro One's investment shall not exceed $5 million) could potentially have learnings that can benefit other regions in Hydro One's service territory, including it in the distribution capital investment plan is reasonable.[17]

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[16] J11.4, pp. 2-3

[17] OEB Staff Submission, EB-2017-0335, *Anwaatin Inc. Notice of Motion for Review and Variance EB-2016-0160 Hydro One Networks Inc. 2017-2018 Transmission Revenue Requirement and Charge Determinant Application.*

B: CUSTOM APPLICATION

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

Background

Hydro One asserted that its proposed Custom IR methodology is consistent with the OEB's *Handbook for Utility Rate Applications* (the Handbook), which states that the test for adequacy of a Custom IR application is: (a) the extent to which its features contribute to the achievement of the OEB's Renewed Regulatory Framework (RRF) goals; and (b) whether it meets certain standards set out in the Handbook, specifically: (i) a minimum five year term; (ii) an index for the annual rate adjustment; (iii) benchmarking; (iv) performance metrics; (v) minimal updates; and (vi) protecting customers.[18]

Hydro One has proposed that, for the five-year Custom IR plan, the annual revenue requirement, and the rates to recover it, be adjusted annually through a "revenue cap index" (RCI) plan.

The basic formula for 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 [TFP] 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 [DSP], beyond the amount of revenue recovered in rates.[19]

Hydro One noted that the design is similar to Toronto Hydro Electric System Limited's (THESL's) current Custom IR plan, which is termed a "price cap index" (PCI). The Hydro One formula is very similar to much the same as that of THESL's Custom IR plan, but

[18] Argument-in-chief, p. 30.

[19] Exhibit A/3/2/p. 2

adds a few additional items.[20] The main common feature is the C-factor, which accounts for the annual increment of approved capital expenditures (in terms of additions to rate base).

The key difference is that THESL's PCI acts directly as the adjustment to rates from one year to the next:

$$P_t = P_{t-1} \times (1 + PCI_t),$$

where P_t is the price (rate) for year t. This is very much like the standard Price Cap rate adjustment mechanism.

For Hydro One's proposal, it is the annual *revenue requirement* that is adjusted by the RCI:

$$RR_t = RR_{t-1} \times (1 + RCI_t)$$

where RR_t is the revenue requirement for year t. Prices are then derived through the allocation of the revenue requirement to all classes, application of the class-specific fixed/variable splits, and then division by the forecasted billing determinants (number of customers, kWh, kW, as applicable). Because the customer and load forecasts are established at the outset for each year of the Custom IR plan term, the actual percentage changes in rates in each year may be different from that year's RCI.

OEB Staff Submission

OEB staff submits that Hydro One's characterization of its proposal as a "revenue cap" is somewhat misleading. As pointed out by OEB staff and acknowledged by Hydro One in an interrogatory,[21] Hydro One could earn more in revenues under certain circumstances, where actual demand is higher than the forecasted demand for that year; in this way, the proposed mechanism is not a "revenue cap" but a "revenue requirement" index.[22]

The use of the "revenue cap index" term for distribution led to a confusing discussion with Hydro One's Witness Panel 1 at the oral hearing[23] with respect to whether the proposed

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[20] Hydro One's witnesses on Panel 1 provided a comparison of the THESL and Hydro One Custom IR plans in testimony. Transcript, Vol. 1 (Juned 11, 2018), p. 60/l. 7 to p. 61/l. 15

[21] Exhibit I/8/Staff-21 b)

[22] It could also earn less. The RCI does not cap revenues, as pointed out by Hydro One's witness. See Transcript, Vol. 10 (June 26, 2018), p. 155/l. 27 to p. 157/l. 1.

[23] Transcript, Vol.1 (June 11, 2018), p. 20/l. 27 to p. 23/l. 22, p. 39/l. 8 to p. 50/l. 27, and Vol. 2 (June 12, 2018), p. 8/l. 7 to p. 9/l. 25, p. 18/l. 23 to p. 21/l. 20

"revenue cap index" formula is consistent with the Handbook, which solely references a "price cap" approach.

In OEB staff's view, this distinction is not significant. The reference to "revenue" in Hydro One's proposed RCI is relates to it being the *revenue requirement* that is adjusted, whereas for the THESL Custom IR, it is a price cap index (PCI) in that it is the *prices* that the PCI is applied to; in both plans, the key aspect is that both are Custom IR proposals for formulaic adjustments, based on forecasted demand and operating and capital costs, of the revenue requirement and rates to recover them over a multi-year plan.

It is OEB staff's view that the reason the Handbook does not refer to "*revenue* cap" but only to "*price* cap" is due solely to the fact that the OEB has had experience with "*price* cap" and similar *price*-adjusting mechanisms over the past two decades, not that it has any objection to *revenue* adjustment approaches. As noted in material in Energy Probe's Compendium for Panel 1,[24] the OEB is familiar with the concept of the *revenue* cap from the development of first generation Performance-Based Regulation (PBR)[25] for electricity distributors.[26]

In light of the above discussion, OEB staff submits that Hydro One's proposed Custom IR methodology is consistent with the Handbook.

Concerns Expressed by Pacific Economics Group

OEB staff retained Dr. Mark Lowry of Pacific Economics Group (PEG) as an expert to review Hydro One's Custom IR proposal, and the total factor productivity (TFP) and cost benchmarking evidence of PSE, Hydro One's expert consultant in this area. PEG also conducted its own analyses and assessed provisions of the Custom IR proposal, which were discussed in PEG's evidence,[27] in responses to interrogatories,[28] and during oral testimony.[29]

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[24] Exhibit K1.4
[25] Since 2006 EDR, the OEB has used the term Incentive Regulatory Mechanism (IRM) as a synonym for PBR.
[26] RP-1999-0034. As noted in the preceding footnote, Energy Probe included several pages from Working Group documents from the RP-1999-0034 process in its compendium for Panel 1, Exhibit K1.4
[27] Exhibit M1
[28] Exhibit L1
[29] Transcript, Volume 11 (June 28, 2018), p. 184 L22 to p. 190 L12.

PEG has commented on PSE's TFP and benchmarking analyses, and has highlighted its concerns, and has made its efforts to correct these in its analyses. In general, OEB staff submits that there are more similarities in the approaches than there are differences. The asset price deflator is a key consideration. This is a real, but technical, issue, which has arisen since Statistics Canada discontinued its Electric Utility Construction Price Index (EUCPI) after 2014. PSE uses U.S. Handy-Whitman indices. While these are well-known, there are potential limitations for them, and for their adaptation to Canadian jurisdictions. PEG has suggested an alternative Statistics Canada measure, the implicit price index for the capital stock of the Canadian utility sector.[30]

PEG also commented that PSE's Ontario local distribution company (LDC) TFP estimate of -0.91% is likely too low, and suggested that not accounting properly for the completion of the smart meter and Advanced Metering Infrastructure (AMI) deployment in Ontario, and the conversion from CGAAP to MIFRS, both occurring between 2012 and 2015, were factors in this. There were other factors which PEG identified in its evidence and highlighted during its testimony.[31] PEG, in its analysis, came up with an Ontario LDC TFP estimate of +0.23%.

However, PEG did concur with the 0% base productivity estimate that Hydro One has proposed and which was supported by PSE.[32] OEB staff concurs with PEG's analyses and recommendations. Econometric models, for TFP or other purposes, are representations of real-world phenomena. They are based on assumptions and on data. Both assumptions and data are often less-than-perfect. The similarities of the experts' analyses outweigh the differences, in the context of this application.

However, OEB staff submits that this is not so say that the differences in the technical differences should or can be ignored. When the OEB considers the next IRM rate-setting regime for electricity distributors, and possibly for other rate-regulated utilities in Ontario, issues of a replacement for the EUCPI, and proper accounting for smart meters and AMI costs, conversion to MIFRS, and other material matters that have arisen since 2012 should be addressed.

[30] Exhibit M1, p. 10

[31] Exhibit M1, pp. 3-4, 10-14

[32] Transcript, Vol. 11 (June 28, 2018), p. 185/ll. 7-20

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

<u>Inflation Factor</u>

Background

Hydro One proposed to utilize the industry-specific inflation factor set by the OEB. Hydro One noted that this inflation factor is created for use in incentive rate-setting under the Price Cap IR and Annual Index rate-setting options and there is no reason to depart from the OEB-established inflation factor under the circumstances of this application.

OEB staff notes that the formula for the 2-factor Input Price Index (IPI) for electricity distributors is a weighted average of the annual changes in labour and non-labour components:

$$IPI = 0.70 \times \Delta GDPIPI(FDD) + 0.30 \times \Delta AWE(Ontario)$$

where:

- GDPIPI(FDD) is the annual Implicit Price Index for (national) Gross Domestic Product, and
- AWE(Ontario) is the annual Average Weekly Earnings for Ontario, all businesses except unclassified, including overtime.

OEB staff notes that both statistics are measured and published by Statistics Canada. The OEB computes and publishes the IPI annually.

OEB Staff Submission

OEB staff notes that there was no opposition to Hydro One's proposal. However, OEB staff's expert, Dr. Lowry, has suggested that Average Hourly Earnings (AHE) could be a potential substitute for AWE.[33]

OEB staff submits that this matter should be left to a generic policy for IRM rate-setting, as the IPI is used for electricity distribution and, with different weights, for OPG's current hydroelectric generation price cap plan.

[33] Exhibit M1/pp. 11-12, and Transcript, Vol. 11 (June 28, 2018), p. 215/ll. 24-28

X-factor, Base X and Stretch Factor

Background

Hydro One stated in respect of the proposed custom productivity factor that its proposed 0.45% stretch factor is the sum of two productivity factors – a custom industry total factor productivity measure of 0%, and a 0.45% custom productivity stretch factor. Hydro One further stated that its proposals are based on the work of PSE, who was engaged by Hydro One to conduct a study of total factor productivity for Hydro One distribution in the Ontario industry as well as a custom econometric benchmarking study of Hydro One's total distribution costs in order to recommend a custom productivity stretch factor.

Hydro One noted that PSE's recommended productivity factors are supported by PEG, which agreed in its report that Hydro One's proposed Custom Industry Total Factor Productivity Measure and the proposed Hydro One stretch factor, and therefore the resulting productivity X factor are reasonable. Hydro One noted, in addition, that the OEB's letter[34] setting out updated stretch factor assignments found that Hydro One should be moved from cohort 5 (0.6% stretch factor) to cohort 4 (0.45% stretch factor).[35]

OEB Staff Submission

OEB staff notes that the X-factor is composed of a base X and a stretch-factor. The base X represents the long-run historical TFP[36] trend in an industry. The stretch factor represents a consumer productivity dividend – a sharing of the increased productivity that the firm can be expected to realize under the multi-year plan with streamlined regulation and more flexibility to adjust operations and investments to meet customer needs and expectations. Additionally, the stretch factor may represent a structural change in regulation, with the transition from traditional cost of service regulation to incentive regulation a commonly cited reason, or it may also be a "stretch" to motivate the firm to consciously attempt to improve its performance relative to the industry and peer firms.

[34] September 14, 2017
[35] Argument-in-chief, pp. 36-37.
[36] Total Factor Productivity or TFP is a technical term in Economics and Econometrics to refer to the productivity – the ratio of the rate of change of all outputs (products and services) of a firm relative to the rate of change of all inputs (capital investments, materials and labour) used to produce the output products and services.

Nearly all IRM plans adopted in Ontario for both electricity and natural gas, since 2000, have explicitly included both the base X and stretch factors, which are integrated (added) into a single X-factor.

As noted previously, OEB staff hired PEG to review Hydro One's Custom IR proposal, and the TFP and cost benchmarking evidence of PSE. PEG also conducted its own analyses and assessed provisions of the Custom IR proposal.

PEG concluded that Hydro One's proposed base X of 0% and stretch factor of 0.45% were reasonable based on its separate TFP analyses and review of PSE's cost benchmarking. However, PEG did express certain concerns with details of PSE's methodologies and attempted to correct (or at least improve) on these.[37]

OEB staff submits that there is accordingly no disagreement with the proposed overall stretch factor of 0.45% for Hydro One based on the analyses of the two expert witnesses. The 0.45% stretch factor is indicative of Cohort 4 (from the OEB's 5-cohort scheme for annual distributor benchmarking), an improvement from Hydro One's historical placement in Cohort 5.

OEB staff notes that while the cost benchmarking indicates improvement, particularly with respect to OM&A productivity, OEB staff expresses concerns below with respect to Hydro One's assessment of the size of its service area, as customer density is a factor taken into account in the cost benchmarking.

However, despite these concerns, OEB staff concurs with Dr. Lowry that, on the basis of the tested and sound evidence, the proposed 0.45% stretch factor, and hence the overall 0.45% X-factor, are reasonable for the proposed 5-year plan.

Hydro One has proposed that the stretch factor not be updated annually, as is done for other Ontario electricity distributors operating under Price Cap IR plans. OEB staff notes that in principle, such an updating could be done, as the OEB commissions an annual benchmarking using the methodology established for the 3rd Generation IRM plan to conduct an annual update. All distributors are included, even those for which the stretch factor is not required for rate-setting in the year (i.e. distributors on the Annual Index

[37] Exhibit M1, pp. 2-3,11-17, and Transcript, Col. 11 (June 28, 2018), p.185x/l. 1 to p.187x/l.17

plan, who get the 0.6% stretch factor automatically, those rebasing and those operating under Custom IR, depending on the rate adjustment formula).

The proposed stretch factor of 0.45% represents an improvement in Hydro One's performance, as it has historically been placed in the last cohort. The improved performance is supported by PSE's cost benchmarking study, and by OEB staff's external expert witness, Dr. Mark Lowry from PEG, based on his own review and analysis.

OEB staff does however note that the analysis undertaken by PSE for Hydro One differs from the annual cost benchmarking done for the OEB in that Hydro One was compared against a group of U.S. investor-owned utilities and rural electric cooperatives, rather than against Ontario electricity distributors.

PSE took this approach so that it could compare Hydro One to utilities with similar size characteristics (number of customers) and customer density. This was done because most Ontario distributors are markedly different from Hydro One in these dimensions.[38] While there are a few Ontario distributors close to Hydro One in terms of number of customers (e.g. Alectra Utilities and THESL), these utilities are urban/suburban and operate in smaller and denser service territories. OEB staff notes that comparisons with other Ontario distributors has been contentious in the past.

OEB staff submits that PSE's attempt to cost benchmark Hydro One against other utilities of similar size and density, reflecting the urban/rural nature of Hydro One's service territory, is reasonable. However, OEB staff notes comments of PEG in evidence and in Dr. Lowry's testimony, of certain concerns with the approach. In particular, as noted, OEB staff does have concerns with Hydro One's reported service territory size.

OEB staff submits that, notwithstanding these matters, for most utilities, updating of the stretch factor results in no change from year to year. OEB staff expects that this would also hold for Hydro One. As such, a requirement to update the stretch factor annually based on a comparison to an extra-provincial peer group, and possibly other Ontario distributors, would not be warranted. OEB staff therefore considers that Hydro One's proposal to hold the stretch factor constant for the plan term is reasonable.

[38] Exhibit A/3/2/Attachment 2/p. 4

However, OEB staff submits that Hydro One should undertake efforts to extend the analysis for its next plan. This should also include data improvements and efforts to include utilities from other Canadian provinces.

<u>Cost Benchmarking – the Issue with Service Territory Size</u>

Background

A concern that has arisen in this proceeding is the size of Hydro One's service area and, by extension, its customer density. More specifically, concerns were expressed that Hydro One's claimed and reported service area is larger than the land area of the Province of Ontario, as reported on provincial government websites. Despite efforts to resolve this apparent inconsistency during the proceeding, a satisfactory explanation was not provided, in OEB staff's submission.

OEB Staff Submission

OEB staff submits that this matter is a relevant concern for the OEB to consider in that customer density is an operational parameter used to normalize comparisons between utilities in cost benchmarking. It is used as such in PSE's Total Cost Benchmarking study[39], and is also a variable in the annual benchmarking analysis conducted by PEG for the OEB to determine the stretch factors used in electricity distributor IRM applications.

While size data – km of line and km^2 of service territory, have been reported under the Reporting and Record-keeping Requirements (RRR) since 2000, concerns about Hydro One's service area were not apparent when compared against most other Ontario distributors. Most municipally-owned distributors serve well-defined urban and suburban areas, with relatively high densities. Only a few distributors, such as Energy+, Kitchener-Wilmot Hydro, Waterloo North Hydro, have urban and rural areas, but still with high density urban areas predominating. Only Algoma Power, serving a rural area (including Lake Superior National Park) outside of Sault Ste. Marie, has a customer density per km^2, lower than Hydro One. It is recognized that Hydro One was an urban-and-rural utility unlike others, and with increases in urbanization due to growth outside of existing

[39] Exhibit A/3/2/Attachment 1

communities, and the acquisition, since 2000, of close to 100 former municipal electric utilities.

However, PSE's cost benchmarking study compared Hydro One to a group of U.S. investor-owned utilities (IOUs) and rural electric cooperatives (RECs). One of the observations was that Hydro One's customer density was lower than the average for the U.S. RECs, and lower than that for most of the RECs. This was questioned through interrogatories and at the technical conference.[40]

OEB staff is of the view that ideally, customers per km of line is a better measure of density, as it more closely corresponds with the quantity of assets, particularly poles, conduit, wires and transformers that the utility has invested in, and must operate and maintain, to provide distribution services to customers. However, there are some concerns over the quality and consistency of that data.[41] As a result, km^2 of service territory is used. PSE noted that it has relied on GIS maps purchased from Platts,[42] for the service areas of all utilities.

The issue, as discussed at the Technical Conference and as was further explored by OEB staff at the oral hearing,[43] is that, as has been previously noted, Hydro One's claimed and reported service area is larger than the land area of the Province of Ontario as reported on Provincial Government websites even after excluding the service areas of all of the other 60+ electricity distributors. OEB staff suggests that this may be explained by the polygon-mapping used by Platts, that does not distinguish inland freshwater from surface land.[44]

[40]Exhibit I/10/Staff-40 and Technical Conference Transcript, Vol, 1 (March 1, 2018), p. 17/l. 25 to p. 19/l. 27, p. 44/l. 25 to p. 47/l. 15

[41] Whether 3-phase wire km. is tripled or not is often cited as one major inconsistency. Per the RRR, it is not supposed to be so reported.

[42] Platts, a subsidiary of Standard & Poors, is an information service provider. Service areas for the vast majority of North American electricity utilities, including maps of the whole of North America, are available for purchase in hardcopy and digital formats.

[43] Exhibit K2.1, pp. 7-12, Transcript, Vol. 2 (June 12, 2018), p. 57/l. 5 to p. 65/l. 7

[44] For Ontario, this would likely mean that James Bay and Hudson Bay and the Canadian/Ontario portions of the Great Lakes and Lake of the Woods are excluded, but all other freshwater lakes and rivers within the boundaries of Ontario are treated as "land".

However, this is not OEB staff's major concern in regard to this matter. The major concern is that Hydro One is claiming all of Ontario except for areas served by other distributors as its service territory. While this may be accurate from a legal perspective,[45] it is artificial from a cost benchmarking perspective and distorts the picture.

This is because Hydro One is claiming huge unserved areas of the province as its service territory in spite of the fact that there is no electrification and no likelihood of electrification in the foreseeable future. Major parks are very obvious examples of this, as pointed out during cross-examination. There are huge areas in northern Ontario which are not parkland, and solely used, if at all, for forestry, and which are unserved (not electrified).

A related concern is the inclusion of Remote Northern Ontario (RNO), that portion of the province basically north of the provincial road network. OEB staff notes that there are a fair number of First Nations communities scattered throughout the area. However, except for three communities along the James Bay shore, those with electrification are served by Hydro One Remote Communities Inc., a separate subsidiary of Hydro One Networks.

Furthermore, the three communities along James Bay (Kashechewan, Fort Albany and Attawapiskat) are served by community-owned distributors.

More recently, there is a project being undertaken by Wataynikaneyap Power, a joint venture of Fortis Ontario and 22 First Nations, to construct a transmission line from the Hydro One grid at Pickle Lake and connect to a number of the First Nations Communities currently served by Hydro One Remote Communities.[46]

OEB staff submits that RNO is currently unserved by Hydro One Networks and, with the initiatives discussed above, it is unlikely that Hydro One will ever be the distributor in the vast majority of RNO. OEB staff notes that unserved territory is, essentially, costless for a utility; the area is not energized and the utility invests in no assets (poles, wires, transformers) in the area and incurs no costs to operate and maintain these non-existent

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[45] Schedule 1 and Appendix B of Hydro One's distribution license ED-2003-0043 (updated February 8, 2018) list the defined areas that Hydro One serves.
http://www.rds.oeb.ca/HPECMWebDrawer/Record/599307/File/document

[46] A map of Watay's planned network and information on commencement of construction earlier this year were provided in Exhibit K2.1, pp. 10-12.

assets. Customers, and the assets to serve them, are only located in the service territory that is energized.

OEB staff's conclusion is that calculating customer density by dividing the number of customers by a service area that is, in large part, unserved, distorts Hydro One's density relative to other distributors. This creates a situation where Hydro One's density is not comparable to that of US utilities (IOUs or RECs) with more precisely measured service territories. This is important, as customer density is a control variable for the cost benchmarking.

OEB staff sees the difficulty as being that the case record does not appear to include a good measure of what Hydro One's actual serviced territory is. In the absence of such a measure, it is not clear to what extent PSE's approach would change relative to the American comparator group.

OEB staff's witness, Dr. Lowry, acknowledged that, while there are concerns, there is not enough information of adequate quality to suggest a stretch factor other than the 0.45% that PSE and PEG have found in their analyses.[47] OEB staff concurs.

However, OEB staff submits that Hydro One should be directed to improve its information on its actual served territory. Alternatively, OEB staff submits that density expressed on customers per km of line may be a preferable measure, despite the data quality concerns that PSE has expressed about km[48] of line as reported by Ontario LDCs, as it is clear that, at least for Hydro One, km^2 of service territory is also erroneous, and by a noticeable order of magnitude.

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

<u>The C-factor</u>

Background

Hydro One noted that the custom capital factor provides the incremental revenue requirement associated with new capital placed into service each year of the custom IR

[47] Transcript, Vol. 11 (June 28, 2018), p. 203/l. 5 to p. 204/l. 1
[48] Exhibit I/10/Staff-44

term. More specifically, the custom capital factor is the percentage change in the total revenue requirement attributable to new capital investment that is not recovered pursuant to the I minus X escalation, including depreciation, return on equity, return on debt and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The proposed capital adjustment factors are outlined in the table below:[49]

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,649.9	8,009.4	8,412.0	8,940.7	9,306.4
2	Return on Debt	E1-1-1	198.6	208.0	218.4	232.0	241.5
3	Return on Equity	E1-1-1	275.4	288.3	302.8	321.7	334.9
4	Depreciation	C1-6-2	398.2	419.3	434.1	453.1	466.8
5	Income Taxes	C1-7-2	65.2	68.7	71.3	78.6	79.2
6	Capital Related Revenue Requirement		937.4	984.3	1,026.6	1,085.4	1,122.4
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.1)
8	**Total Capital Related Revenue Requirement**		**937.4**	**979.9**	**1,022.0**	**1,080.5**	**1,117.3**
9	OM&A	C1-1-1	576.7	581.1	585.4	589.8	605.1
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,514.2**	**1,561.0**	**1,607.4**	**1,681.0**	**1,722.4**
12	Increase in Capital Related Revenue Requirement			42.5	42.1	58.5	36.8
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.80%	2.70%	3.64%	2.19%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.34%**	**2.23%**	**3.16%**	**1.71%**

Hydro One stated that the capital factor is required in order to ensure that it can invest in its capital as required by the DSP and in order to meet customer expectations in relation to reliability.

OEB Staff Submission

OEB staff notes that the capital factor (C-factor) is directly based on the C-factor proposed, and approved, in THESL's current Custom IR plan.[50] The C-factor is an adjustment to the formula to reflect the increase in the revenue requirement due to the approved capital increment. The C-factor adjusts the prior year's revenue requirement.

OEB staff submits that methodologically speaking, the concept of the C-factor is logical. However, it is the practical implementation of it – specifically on the level of forecasted capex and capital additions for each year of the plan, and relative to changes in demand and capital cost inflation – on which the reasonableness of the proposal is based.

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[49] Argument-in-chief, pp. 37-38 and p. 20.
[50] EB-2014-0116

Hydro One has made its Custom IR proposal on the basis of its specific capital needs (and also related operating costs for specific programs such as vegetation management) over the five-year period, consistent with the conceptual need for the Custom IR as outlined in the RRFE Report.[51] Hydro One has provided documentation on its capital and operating programs and major projects in the evidence, with much of this contained in the DSP.[52] The contents of the DSP have been extensively tested throughout this proceeding, and OEB staff's positions on the DSP are documented later in this submission.

Customer Growth

One factor commonly seen in revenue cap mechanisms that is missing from Hydro One's proposed RCI is a "g" factor, intended to account for growth in demand (number of customers, consumption and energy demand). This omission has been pointed out by PEG, by various intervenors, and acknowledged by Hydro One itself.

The impact of its omission from the annual RCI formula is that OM&A expenses, in aggregate, escalate less than expected for a price cap approach, as the adjustment is for inflation less expected productivity but there is also no increase for operating costs to serve added customers, such as billing and mailing costs. Implicitly, Hydro One is actually assuming that OM&A productivity of X + g, or about 0.45% + 0.67%[53] = 1.12%. (In reality, not all OM&A costs increase on a 1:1 basis for each added customer; there may be economies of scale possible for many expenses. For example, costs related to (amongst other matters) finance and accounting, human resources and insurance will not change materially for added customers once a certain size is achieved.)

However, OEB staff submits that Hydro One's proposal overall is not as favourable to customers as the OM&A productivity discussion above suggests. This was tested

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[51] *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 13, Table 1 - Rate-Setting Overview - Elements of Three Methods, pp. 18-19. The Rate Handbook, issued October 13, 2016 reaffirms the applicability and attributes of the Custom IR approach.

[52] Exhibit B1-1-1.

[53] Exhibit K2.1, p. 25

through cross-examination of Hydro One's witness panels 1 and 5.[54] In particular, OEB staff asked about Exhibit K2.1/page 25,[55] to explore the extent to which Hydro One's forecasted capital expenditures/additions are growing over the five-year period, and to demonstrate that it is the capital additions growth which is driving the overall growth in revenue requirement. OEB staff's analysis[56] shows that, even when taking into account customer growth of about 0.67% per annum, rate base is increasing by over 2%, and even above 2.5% in some years. Further, OM&A represents just under 40% of the revenue requirement – it is the capital-related revenue requirement which dominates. It is the higher growth rate of the dominating capital-related portion of the revenue requirement which allows Hydro One to omit the "g" factor for OM&A, as it more than makes up for it with the forecasted capex increases above and beyond customer growth.

Hydro One's proposed C-factor, and without an explicit "g" factor for both OM&A and capex, obfuscates the capital growth. As OEB staff's witness, Dr. Lowry, noted during his testimony, explicitly adding in a "g" factor would allow for a distinction between growth-related capex and other capex. This can be worthwhile. Hydro One, like regulated utilities in Ontario and elsewhere, has an obligation to serve subject to certain conditions being met. Thus, growth-related capex to connect new customers is necessary. It is the non-growth-related capex which is more at issue, specifically with respect to what is the need for, the benefits of, and the necessary quantum of work and the costs that are justified and prudent.

Hydro One's cross-examination of Dr. Lowry appeared to be based on the proposition that, if a "g" factor was included, and the C-factor adjusted to exclude growth in customers and/or demand, there would be no net change in the capital additions to rate base and hence to the revenue requirement and rates.[57] This is true, all else being equal. However, separating out the growth-related capital from other capital may provide differentiation between non-discretionary and discretionary capital.

OEB staff submits that non-discretionary capital for connecting new customers (growth-related capital) is not as much of a concern if cost levels and load forecasts are reasonable. It is other, more discretionary, capital that is more at issue.

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[54] Transcript, Vol. 2 (June 12, 2018), p.65/l. 11 to p. 73/l. 26, Vol. 9 (June 25, 2018), p. 109/l. 4 to p. 112/l. 20

[55] Also provided in working Microsoft Excel format.

[56] Exhibit K2.1, p.25.

[57] Transcript, Vol. 11 (June 28, 2018), p. 204 L2 to p. 206 L5.

The issue of whether adequate support has been provided for discretionary capital expenditures is dealt with in the DSP and discussed in more detail elsewhere in this submission. However, as suggested by PEG, there may be a benefit to include a "g" factor for growth to adjust both operating and capital expenditures, and to revise the C-factor downwards. Inclusion of the "g" factor would, in OEB staff's submission, also be consistent with the current THESL Custom IR approach. More importantly, it would more clearly allow for differentiation between non-discretionary, growth-related capital, and more discretionary capital spending, which allowance the OEB should approve depending on the support for the projects, including need for, benefits and the overall level of spending.

Other Custom IR Plan Provisions

Background

In its application, Hydro One documented other proposed features of its proposed Custom IR plan, specifically:[58]

- Earnings Sharing Mechanism (ESM)
- Capital In-Service Variance Account (CISVA)
- Z-factor
- Off-ramps

OEB Staff Submission

The ESM is discussed under Issue 15. The Z-factor and Off-ramps are discussed under Issue 16. OEB staff makes its submissions on the CISVA under Issue 58.

[58] Exh. A/3/2.

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

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

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

OEB staff has considered and addressed these three issues together.

Background

Hydro One noted that it had filed three program-based benchmarking studies in its initial application: a vegetation management benchmarking study conducted by CN Utility;[59] a pole replacement and station refurbishment benchmarking study conducted by Navigant;[60] and an information technology (IT) budget assessment study conducted by Gartner.[61] In addition, Hydro One also filed a study concerning its new vegetation management program from Clear Path.[62]

Hydro One submitted that it had appropriately considered these studies and that they had assisted in its planning process with independent reviews of its largest non-demand work programs and peer group comparisons, which are one means of assessing its practices and costs against other industry participants. Hydro One submitted that, broadly speaking, each of the benchmarking studies shows that it compares well against its peers as each of the Navigant, CN Utility and Gartner studies found that Hydro One's performance is in line with its peers.[63]

OEB Staff Submission

OEB staff believes that each consultant has reasonably followed accepted approaches

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[59] DSP, Section 1.6, Attach. 2.
[60] DSP, Section 1.6, Attach. 1.
[61] DSP, Section 1.6, Attach. 3.
[62] Exh. Q-1-1, Attach. 2.
[63] Argument-in-chief, pp. 39-40.

for its study[64] and notes that the benchmarking studies, and their impacts on Hydro One's application, and more generally on its operations, have been extensively tested in this proceeding.

OEB staff submits, however, that from an overall perspective, it is not possible to identify the impact of these studies on the proposed Custom IR plan and on the revenue requirement of which Hydro One is requesting approval. First, this is because these benchmarking studies deal with specific capital and operational programs which are, individually, only portions of Hydro One's total portfolio. Second, Hydro One's proposal is for an overall plan (Plan B Modified), which was developed as a result of proposals to and feedback received from Hydro One's Board of Directors. It is not clear how much the results of these benchmarking studies influenced strategic decisions by the Board of Directors or senior executives.

That being said, OEB staff notes that one area – vegetation management – exhibits a change from the past, in that Hydro One is proposing to transition to a significantly shorter cycle than its historical practice with no increases in costs to customers. OEB staff notes that a shorter cycle would be supported by the benchmarking results, but OEB staff also notes that Hydro One's longer cycle has also been an issue extensively tested in previous applications, with recommendations to reduce the cycle length, though not to the extent that the Clear Path study is proposing. OEB staff is of the view that, if Hydro One can achieve the results that it has stated are possible based on the Clear Path proposals, this would be a positive development for its customers both from a cost and reliability perspective.

The result of the IT benchmarking had an impact, as discussed during the oral hearing,[65] in that Hydro One is proposing a lower threshold for capitalizing IT projects, consistent with many other firms surveyed in the study. However, Hydro One stated that this change would have no or minimal impact.

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[64] For example, OEB staff acknowledges that Hydro One's consultants explained that they attempted to contact various firms as comparators, including making follow-up contacts. (Transcript, Vol. 5, (June 18, 2018, p. 134/l. 1 to p. 135/l. 16, p. 142/l. 12 to p. 147/l. 24) However, they noted that contacted firms are under no obligation to participate – their participation is voluntary, with individual firm results given under an agreement of anonymity. Follow-ups to understand data anomalies may be attempted, but may be limited by time and resources.

[65] Transcript, Vol. 10, p.41 L14 to p. 42 L10.

With respect to Navigant's pole replacement study, it is pointed out that Hydro One has the longest average age of poles in the study. It is not clear to OEB staff what the implications of this are as the comparator firms are from all over North America, the types of poles used may differ, and the environmental conditions and risks may be different from those of Hydro One.

OEB staff notes that one item that did stand out was on the idea of reinforcement or refurbishment of an "at risk" pole if there is sufficient remaining expected life for the pole and other situational parameters would make reinforcement or refurbishment an option. However, as explored during the oral hearing, while Hydro One may consider this approach, there does not appear to be anything definitive at this time.[66]

With respect to station refurbishment or replacement, Hydro One's witnesses noted that, due to the size and low customer density in many parts of its service territory, many transformer stations are single transformers. OEB staff notes that this is different from the situation for many of the comparator firms in the benchmarking study; as has been highlighted during the proceeding.[67]

OEB staff submits that it is not clear how much the results of this study have informed the application, if at all. Hydro One already has certain assets and practices to assist it in managing transformer refurbishment and rebuilds. As one obvious example, the mobile transformer trailers are designed to allow Hydro One to maintain supply to customers served from a single transformer distribution station while it is de-energized for refurbishment or replacement. OEB staff notes that this is an established practice.

OEB staff considers that the benchmarking studies are individually credible in and of themselves. However, OEB staff has two concerns: With respect to the first part of Issue 12, on whether these studies are aligned with each other, following extensive review of these studies over the course of this proceeding, OEB staff considers that these studies are not aligned with each other. In addition, it turns out, in OEB staff's view that this fact is not relevant as each benchmarking study is with respect to a separate capital or operating program and, as determined through OEB staff's review, there is little or no

[66] Transcript, Vol. 8, p. 28 L8 to L23.
[67] Transcript, Vol. 5 (June 18, 2018), p. 159/l. 2 to p. 160/l. 2, p. 180/l. 2 to p. 181/l. 4

overlap between these studies.[68]

Furthermore, with respect to the second part of Issue 12 regarding alignment with Hydro One's overall Custom IR plan, and Issues 10 to 12 generally, OEB staff is not convinced as to the extent these studies have informed Hydro One's five-year application. OEB staff concludes that alignment with the Custom IR application is not apparent, and to the extent that any such alignment exists, it may be coincidental rather than planned.

OEB staff suggests that the OEB may wish to address this matter, and indicate its expectations as to how Hydro One should conduct future detailed program and project benchmarking so that it is more clearly demonstrated how the results do factor into future applications. Given these limitations in the current application, OEB staff considers that the program-based benchmarking studies must be assessed solely in the context of the specific capital and operational programs that each pertains to; they cannot be used for informing the appropriateness of the Custom IR plan overall. OEB staff has considered the program-based benchmarking results on capital and operating costs in later sections of this submission.

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

Background

Hydro One stated that it has worked to minimize the number of updates during the course of the Custom IR term consistent with the Handbook. Hydro One further stated that it expected to file annual update applications[69] which would:

1. Calculate the revenue requirement using the revenue cap index, based on the OEB's most recent inflation factor for distributors;
2. Derive new rates based on the updated revenue requirement and the approved load forecast for the coming year; and
3. Consistent with the requirements of IRM applications, seek to update Hydro One's retail transmission service rates and review and dispose of Group 1 deferral and variance account balances as necessary.

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[68] The only two benchmarking studies where there could be some overlap is with respect to vegetation management and pole replacement. Improved vegetation management could reduce pole failures due to tree falls, as an example, but this is largely a coincidental, beneficial impact of one program on another.

[69] Argument-in-chief, pp. 40-41.

Hydro One stated that in addition to these items, it is also proposing to update its cost of capital parameters and load forecast in 2021. Hydro One explained the purpose of these updates as being that they are key inputs to the cost allocation model and would ensure fairness in the allocation of costs between all of Hydro One's rate classes by relying on the most recent information when rates are first established for the Acquired Utilities at the time of their integration into Hydro One's rate structure. Hydro One stated that it would make any necessary updates to the proposed rate design (e.g. revenue-to-cost ratios) that may arise from these updates. Hydro One stated that this process is proposed in relation to 2021 in order to ensure that customers of Acquired Utilities are charged rates which reflect the costs to serve them. On this basis, Hydro One submitted that its proposed 2021 updates are reasonable.

OEB Staff Submission

OEB staff notes that annual rate applications to establish updated rates for each year of the plan are normal for Custom IR plans and have been approved in similar applications of other natural gas and electricity distributors (e.g., Enbridge Gas Distribution, THESL, and Horizon Utilities (now part of Alectra Utilities).

While most of the elements of Hydro One's proposed plan are common with other existing plans, the adjustments related to the Acquired Utilities would be unique to Hydro One's application, if approved as proposed.

As such, for the 2021 application (to be filed in 2020), there will be additional complexity, and greater work required for review and processing. If the current application is approved as proposed, the updated IPI will not be known until September 2020, and this will determine the updated 2021 revenue requirement, including the addition of operating expenses and rate base for the acquired LDCs. The allocation of the revenue requirement and determination of rates will be somewhat more complicated by the addition of the new Acquired Utilities classes, and the apportionment of the revenue requirement across all of these classes.

Hydro One has also proposed that the cost of capital parameters be updated at this time – this would specifically be for the ROE, although the deemed short-term debt rate and, potentially, the (actual) long-term debt rate could also be updated. The proposal to update the cost of capital parameters is a deviation from the policy in the Handbook:[70]

[70] Rate Handbook, October 13, 2016, p. 26-28.

> Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

Hydro One has argued that this update is necessary since the legacy rate bases of the Acquired Utilities were each last rebased at different times, and so the revenue requirements reflect different costs of capital. Hydro One's proposal would apply a common cost of capital to the legacy and Acquired Utilities' rate bases for the integration (i.e., the revenue requirement would be on a common basis for the allocation to all classes and determination of rates in 2021 and going forward.) However, an alternative option, and which is OEB staff's preference, as described in more detail below, would be to use the 2018 cost of capital parameters approved in this current application instead.

OEB staff submits that with the integration of the acquired LDCs in 2021, there is a distinct possibility of increased variability in rate impacts, which may also mean that there is an increased possible need for rate mitigation with both legacy and acquired LDC customer classes potentially being impacted.

While OEB staff considers that the proposed annual rate filing approach for 2021 is reasonable, it will involve a more detailed review than will be the case for other years of the rate-setting period. Hydro One should be expected to file the application earlier in the 2020 year to allow for the addition review and processing for the integration of the acquired Utilities, the cost allocation and the rate and bill impacts on all of Hydro One's customers.

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

Background

Hydro One stated that it proposed to integrate the customers of the Acquired Utilities in its rate structure in 2021 and that this was appropriate as it aligns with the five year rebasing deferral period approved by the OEB in each of its decisions approving Hydro One's acquisitions of these utilities, with the exception of Norfolk, in respect of which Hydro One proposes to maintain the rate freeze on Norfolk customer rates for an additional sixth year. Hydro One submitted that this approach allows for the integration of all acquired customers in the same year and is beneficial to Norfolk ratepayers who will enjoy an additional year of frozen rates.[71]

OEB Staff Submission

OEB staff notes that Hydro One's integration proposal is a unique aspect of its application and, as explained by Hydro One, the integration of the acquired Utilities is the main basis for structuring its Custom IR proposal as a revenue cap rather than a more familiar (in Ontario) price cap. Hydro One's witness acknowledged that the integration could be accomplished under a price cap approach, but also stated that it is easier to accomplish under the revenue cap approach.[72] OEB staff concurs with this; the revenue cap approach allows for addition of the rate base and operating expenses of the acquired Utilities to those of the legacy Hydro One. Through a cost allocation that adds on the allocators for the new proposed acquired Utilities rate classes, the integrated revenue requirement is reallocated and new rates will be derived for all legacy and acquired Utilities rate classes.

Hydro One's proposal is that the customer and load forecast be updated for 2021 for the legacy customers and the Acquired Utilities. These factor into the cost allocation model so that the cost allocation and, ultimately, rates would be impacted. However, costs would not be updated except to the formulaic update of the I – X to OM&A expenses, and the update to the cost of capital (the latter discussed below and under Issue 13 above).

Should the OEB approve the integration of demand and assets for the new Acquired Utilities rate classes in 2021 as proposed by Hydro One, OEB staff considers that the methodology proposed by Hydro One to be reasonable, with two caveats.

First, as discussed under Issue 13 above, the OEB could approve that the cost of capital be updated for 2021 for all of Hydro One's revenue requirement as the utility has

[71] Argument-in-chief, p. 41.
[72] Transcript, Vol. 10 (June 26, 2018), p. 81/l. 11 to p. 82/l. 21, p. 116/l. 7 to p. 120/l. 21,

proposed, or it could determine that the cost of capital approved in this application (i.e., for 2018) be used. OEB staff submits that what is important is that the cost of capital parameters be consistent for both the legacy and acquired Utilities assets at the time of integration.

Second, Hydro One’s proposal creates a methodological issue in another vein. As typically done in a cost of service application to rebase rates, all of the information is a “snapshot” in time – the customer and load forecast, and the historical or forecasted costs for serving that demand, and the allocators and rate design parameters used for allocating between customer classes and to determine the rates to recover the annual revenue requirement – are fixed as the “best” available information at that point.

Hydro One has proposed that the load forecast and cost allocation be updated for 2021, which includes the impact of integrating the customers and demand and the assets and operating costs of Hydro One’s legacy customers and assets with those of the acquired Utilities. This will mean that the load forecast for the 2021 application filed in 2020 would reflect 2018 and 2019 actuals. However, operating and capital costs would not be, except for the formulaic I – X adjustment to the OM&A expense forecast. Capital additions to rate base would be as approved in this application, and even the OM&A would be a straight adjustment from the approved 2018 OM&A plus the adjustment for expenses for the acquired LDCs’ service territories. This creates a deviation from the standard approach in that some of the information is to be updated for 2021, but not other information. Hydro One’s proposal may improve the currency of the cost allocation, but the costs being allocated may be outdated, which introduces another source of measurement error in the derivation of 2021 rates.

Further, updating for the load forecast and the cost allocation, but not the costs may have unanticipated impacts, due to two factors:

1) Changes in socioeconomic conditions, including changes in energy (electricity) policy in Ontario could impact demand

2) Different growth rates (for both number of customers and demand) between different classes would result in differences in allocators and hence shifting of costs between classes. This could not only be between residential and commercial and industrial classes, but even between legacy and the new Acquired Utilities classes.

Thus, even despite the consideration of allocation of costs between legacy customers and customers in the Acquired Utilities tested in this application, the 2021 update as proposed could re-open such issues.

OEB staff submits that an alternative would be to approve and fix the forecasted 2021 numbers for costs (capital and, subject to the I – X adjustment, OM&A, and for demand (customers, kWh, kW) in its decision for this application. Essentially, except for the inflation-less-productivity adjustment of OM&A, the costs, demand and cost allocation would be fixed at the "snapshot" used at this point in time. This is OEB staff's preferred approach.

OEB staff is of the view that such an approach would be consistent with the Custom IR policies in the RRFE Report and the Handbook, in that it would avoid a mid-period updating of information.[73] It could result in some risk arising from the possibility of material changes from the forecasts in this application. In such a situation, the revenue requirement, its allocation to customer classes, and the calculation of rates by class to recover the revenue requirement could be impacted. However, given the evidence filed and tested in this application for the five-year period, and the relative size and impact of the acquired Utilities to Hydro One's legacy demand and costs, the error and risk should be relatively minor for the proposed Custom IR plan of five years, even with the acquired Utilities integration. Any need for a "re-opener" if demand and costs materially change should be dealt with on a case-specific basis.

15. Is the proposed Earnings/Sharing mechanism appropriate?

Background

Hydro One has proposed an ESM to apply for all years of the Custom IR plan.[74] The proposed ESM is asymmetrical, with a 50/50 sharing of any achieved ROE exceeding the allowed ROE on a regulated basis by 100 basis points for each test year. The mid-

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[73] Handbook, p. 26: "Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application."
[74] Exhibit A/3/2/p. 9/section 2.1

year rate base will be used to calculate the ROE for each year. Any excess earnings to be refunded to customers would be adjusted for tax impacts in the year, and accumulated in a deferral account (DVA). Hydro One proposes that any refund would be disposed of at the time of its next rebasing.

OEB Staff Submission

OEB staff does not oppose the proposed ESM. With respect to the proposed DVA and disposition of any balance at Hydro One's next rebasing application, OEB staff makes the following two submissions:

1) Interest should accrue annually to any balance of the proposed DVA at the prescribed DVA interest rate, consistent with Hydro One's response to an interrogatory from Canadian Manufacturers and Exporters (CME).[75]

2) While Hydro One proposes disposition at the time of its next rebasing application, this would presumably only be for any balance up to December 31, 2021. Assuming that Hydro One files in 2022 to rebase rates for January 1, 2023, any overearnings in 2022 would not be known. Any overearnings achieved in 2022 would only be finalized on an audited basis sometime in 2023 and thus be disposed no earlier than for 2024 rates. Thus, if the ESM proposal is approved, the DVA and its details would survive to at least December 31, 2023. Hydro One has agreed with this in response to an interrogatory from OEB staff.[76]

[75] Exhibit I/15/CME-7 part h)
[76] Exhibit I/15/Staff-64

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

Z-factor

Background

Hydro One has documented its proposed Z-factor approach. It states that its approach is consistent with the Handbook, and that "[t]he criteria that would apply to the use of the Z-factor mechanism are those outlined by the Board in Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications and the guidelines provided in section 2.6 of the Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (July 14, 2008)".[77] In response to an interrogatory, Hydro One has confirmed that the proposed materiality threshold for a Z-factor would be $1 million.[78]

OEB Staff Submission

OEB staff notes that Hydro One has a larger rate base than any other Ontario electricity distributor, and that the materiality threshold for large utilities has become an issue in recent applications (e.g., OPG has a $10 million Z-factor materiality threshold,[79] Enbridge Gas Distribution a $1.5 million[80] and Union Gas a $4 million[81] materiality threshold). Hydro One transmission has a Z-factor materiality threshold of $3 million, as established in the Filing Requirements for Electricity Transmitters.[82]

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[77] Exhibit A/3/2/p. 11/section 3

[78] Exhibit I/16/CCC-18. See also Exhibit I/16/CME-10.

[79] EB-2016-0152

[80] EB-2012-0459

[81] EB-2013-0202, Exhibit A/Tab 1/page 36 of 54 (Settlement Agreement on Union Gas' 2014-2018 Price Cap IR plan)

[82] *Filing Requirements for Electricity Transmission Applications: Chapter 2: Revenue Requirement Applications*, February 11, 2016, p. 6, Section 2.1.1:

"Unless a different threshold applies to a specific section of these filing requirements, the default materiality thresholds are as follows:

• $50,000 for a transmitter with a transmission revenue requirement less than or equal to $10 million

• 0.5% of transmission revenue requirement for a transmitter with a transmission revenue requirement greater than $10 million and less than or equal to $200 million

• *$3 million for a transmitter with a transmission revenue requirement of more than $200 million*" [Emphasis added]

While OEB staff notes that Hydro One's proposal for a $1 million Z-factor materiality threshold is consistent with the electricity distribution filing requirements, OEB staff also notes that the issue of "right-sizing" has become a consideration in many recent applications for larger utilities. The issue is that the fixed threshold does not change, while the rate base and revenue requirement of a utility generally increases over time, due to inflation, growth in customers and demand, and growth in network investments and operations. Mergers and acquisitions further augment this growth. The result is that a $1 million materiality threshold represents a much smaller fraction of the utility's revenue requirement. In theory, a firm could apply for Z-factor treatment even though it is capable of dealing with the cost consequences of an exogenous event due to its increasing size, revenue requirement and cash flow.

While OEB staff does not oppose Hydro One's proposed Z-factor treatment, and the proposed $1 million materiality threshold, OEB staff also suggests that an option available to the OEB would be to right-size the materiality threshold. Such an option is contemplated in the Handbook for Custom IR plans.[83]

OEB staff would suggest one possibility might be a materiality threshold of $3 million, based on the concept that, if Hydro One transmission has a threshold of $3 million based on a revenue requirement of about $1.5 billion,[84] then a similar $3 million materiality threshold for Hydro One distribution would be proportionate given its proposed revenue requirement of about $1.45 billion. (The Transmission Filing Requirements do not identify whether the materiality threshold is on a cost or revenue requirement basis for transmitters. However, the Filing Requirements for Electricity Distributors[85] do identify that materiality is determined on a revenue requirement basis, and this is consistent with the policy and precedent for natural gas utilities.[86])

OEB staff also believes that the OEB should confirm in its decision that the Z-factor materiality threshold applies on a revenue requirement basis. In other words, a capital expenditure would have to be much larger than $3 million to qualify to Z-factor treatment

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[83] Handbook, p. 27

[84] EB-2017-0260, Decision, Hydro One Networks 2018 Transmission Revenue Requirement, December 20, 2017, p. 5.

[85] *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 2 Cost of Service*, (July 20, 2017), p. 5

[86] Decision with Reasons EB-2012-0459, July 17, 2014, p. 20 and EB-2013-0202/Exhibit A/Tab 1/page 36 of 54 (Settlement Agreement for Union Gas' 2014-2018 Price Cap IR plan)

(assuming the other criteria are satisfied) as there would have to be an annual revenue requirement impact of $3 million arising from the capital expenditure to meet the threshold.

Off-ramps

Background

With respect to off-ramps, Hydro One proposes "to adopt the Board's existing off-ramp mechanism; a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review of the Revenue Requirement arising from Hydro One's Custom IR may be initiated."[87]

OEB Staff Submission

OEB staff does not have concerns with Hydro One's proposal. While the Handbook infers that a 300 basis points off ramp may not be appropriate in all cases and should be considered in combination with the remaining customized parameters, in this case, OEB staff is satisfied with the use of a 300 basis points threshold. OEB staff notes that this off-ramp is in addition to the proposed ESM, which is asymmetrical (in favour of sharing with ratepayers) with a 100 basis point threshold. The off-ramp threshold would be based solely on Hydro One's regulated distribution operations.[88]

C: OUTCOMES, SCORECARD AND INCENTIVES

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?

Background

Hydro One provides in the application a table[89] which demonstrates how its business objectives align with the four outcomes identified in the Handbook, specifically customer focus, operational effectiveness, public policy responsiveness and financial performance.

[87] Exhibit A/3/2/p. 12/section 4
[88] Exhibit I/16/Staff-65
[89] Exh A, Tab 3, Sch 1, p. 11 Filed:2017-03-31

Customer Focus

Hydro One submitted that this outcome was adequately incorporated as the application is focused on addressing and balancing customer needs and preferences. Hydro One stated that the application was prepared with the benefit of an extensive early consultation process led by IPSOS as well as ongoing feedback Hydro One received from its day to day interactions with customers.[90]

Operational Effectiveness

Hydro One submitted that operational effectiveness had been demonstrated through its productivity evidence, which showed that approximately $398 million in productivity savings had been embedded over the course of the plan. Hydro One argued that these productivity savings reduce the capital requirements from 2018 to 2022 and reduce the OM&A requirement during the rebasing year.[91]

Public Policy Responsiveness

Hydro One submitted that the application demonstrates that it is responsive to public policy initiatives. Hydro One noted in this context that the application took into account the Fair Hydro Plan and that it was also fulfilling its commitment to the smart meter program by budgeting for the commencement of replacement of smart meters in 2022. Hydro One also argued that the aggressive targets it had set for itself for public policy responsiveness measures on the Distribution OEB Scorecard would ensure that it would maintain its commitment to public policy responsiveness over the course of the plan.[92]

Financial Performance

Hydro One submitted that the application appropriately addresses the financial performance outcome objective as it allows Hydro One the opportunity to earn a fair return. Furthermore, incentives are also provided through the ESM with savings that result in a return on equity 100 basis points higher than the OEB approved ROE being shared with customers. As well, the CISVA also ensures that Hydro One is incentivized to meet its financial targets, while also ensuring that ratepayers are given protection. As was the case with public policy responsiveness, Hydro One argued that the aggressive targets it had set for itself for financial performance measures on the Distribution OEB

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[90] Argument-in-chief, p. 43
[91] *Ibid*, p. 45
[92] *Ibid*, p. 46

Scorecard would ensure that it would maintain its commitment to financial performance over the course of the plan.[93]

OEB Staff Submission

OEB staff submits that Hydro One has adequately incorporated the public policy outcome as it has been responsive to changes in public policy as it has outlined above. OEB staff has concerns with Hydro One's incorporation of the other three outcomes in the application.

OEB staff expresses some concerns with Hydro One's incorporation of the customer focus outcome with respect to the nature of its engagement of its customers regarding the DSP under Issue 23.

OEB staff notes that with respect to operational effectiveness, Hydro One submitted that it had demonstrated this through its productivity evidence. OEB staff has concerns with this evidence which it discusses under Issue 21. OEB staff also expresses more general concerns regarding the extent to which this outcome has been reflected in the application in Section D, which is the DSP and capital expenditure discussion and Section F, which discusses Hydro One's projected expenses, including compensation.

With respect to Financial Performance, Hydro One stated that the aggressive targets it had set for itself on its Distribution OEB Scorecard would ensure that it would maintain its commitment to financial performance over the course of the plan. OEB staff expresses its concerns with these measures in its submissions under Issues 18, 19 and 20 which follow.

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

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

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?

[93] *Ibid,* p. 47

Background

Hydro One stated that as part of its internal operating systems and external reporting requirements, it has several scorecards that it maintains and reports against. It further notes that there are three primary scorecards that relate to its distribution business, which are:

- Electricity Distributor Scorecard;
- Distribution OEB Scorecard; and
- Team Scorecard.

Electricity Distributor Scorecard

Hydro One noted that this scorecard is the OEB mandated scorecard for all electricity distributors in the province.

Hydro One stated that the RRF is an outcomes-based approach to regulation and that it recognizes the need to demonstrate how it will achieve the four RRF outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. Hydro One concluded that the Electricity Distributor Scorecard shows Hydro One's success in achieving these outcomes and the performance levels that Hydro One expects to achieve over the 2018 to 2022 rate setting period.

Distribution OEB Scorecard

Hydro One stated that the Distribution OEB Scorecard is a proposed scorecard developed by Hydro One to supplement the Electricity Distributor Scorecard and contains additional measures that provide greater transparency to the outcomes that customers value and to areas that Hydro One has targeted for improved performance.

Hydro One further stated that it is committed to both sets of performance measures as it evaluates its progress executing its 2018 to 2022 investment plan that aligns the needs and preferences of customers, compliance and condition needs of its assets and rate impacts. Hydro One further stated that its plan has a number of initiatives that control costs, increase productivity and maintain levels of reliability in rural and urban areas and that these are all outcomes that customers have indicated they value, are central to Hydro One's business objectives and the RRF.

Team Scorecard

Hydro One stated that the Team Scorecard, which is its internal corporate scorecard, is a shared short term compensation scorecard for all Hydro One management staff.

Adequacy of Performance Monitoring and Reporting Proposals

Hydro One stated that it had in place a robust performance monitoring and reporting process designed to drive accountability for management and provide transparency for the OEB and for Hydro One's customers. Hydro One further stated that alignment of the measures from the Electricity Distributor Scorecard and the proposed additional scorecard measures in the Distribution OEB Scorecard to the Team Scorecard demonstrates the promotion and incentivization of appropriate outcomes in the application, as management compensation is directly impacted by Hydro One achieving the targets it has set for itself on these outcome measures.[94]

Promotion and Incentivization of Appropriate Outcomes

Hydro One stated that the application promotes and incentivizes appropriate outcomes through the Team Scorecard, built-in productivity targets and the ESM. Hydro One submitted that the Team Scorecard has a direct impact on management compensations and therefore management is incentivized to meet the targets that Hydro One has set for itself. Hydro One added that the measures in the Team Scorecard reflect each of cost control, system reliability, service quality and bill impacts, while other Team Scorecard metrics, such as Health and Safety, and Net Income reflect other important outcomes.[95]

OEB Staff Submission

OEB staff notes that in this application Hydro One has provided the OEB's Electricity Distributor Scorecard along with two Hydro One-specific scorecards – the Distribution OEB Scorecard and the Team Scorecard.

OEB staff has concerns that the proposals for performance monitoring and reporting as reflected in these scorecards may not collectively be adequate to sufficiently focus Hydro

[94] Argument-in-chief, p. 56.
[95] Ibid, pp. 57-58.

One during the 2018-2022 rate-setting period on outcomes that appropriately reflect customer expectations.

Where the OEB's Electricity Distributor Scorecard is concerned, Hydro One has provided targets for the 2018 to 2022 period for some of these indicators, but many others are marked as N/A where targets are concerned, such as "Total Cost per Customer" and "Total Cost per km of Line," as well as all financial ratio indicators. The targets for some of the other indicators would not appear to be particularly challenging to achieve, given Hydro One's historical achievement levels, such as 98% for "New Residential/Small Business Services Connected on Time," when the 2016 and 2017 achieved levels were 98.60% and 98.06% respectively.[96]

The Distribution OEB Scorecard is one developed by Hydro One that is included in the DSP. As is the case with the OEB scorecard, many of the targets shown do not appear to be very challenging for Hydro One to achieve given its historical performance and, in some cases, the targets set appear to represent worse levels of achievement than are currently being achieved. In the former category for instance, Hydro One achieved a 76% customer satisfaction level in 2017 related to the indicator "Handling of Unplanned Outages Satisfaction%" but is only targeting an increase to 77% in 2018 and 78% in 2019. In the latter category of worse levels of achievement, there are a number of examples. For the indicator "Pole Replacement – Gross Cost Per Unit in $," the unit cost is shown as $8,350 in 2016 and $8,431 in 2017 with higher costs targeted for 2018 and 2019 of $8,733 and $8,908 respectively. Similarly, the indicator "Number of Line Equipment Caused Interruptions" is shown as being at 7,674 in 2016 rising to 8,786 in 2016, but the target for 2018 is 8,200, although a substantially lower level was achieved in 2016.[97]

Where the Team Scorecard is concerned, OEB staff notes that while there are relatively few indicators on this scorecard in the first place, a number of those that are there are either exclusive to transmission, indicators applicable to Hydro One as a whole, not just distribution,[98] or redacted (the net income indicator).

[96] Exh I, Tab 18, Sch SEC-29, p. 3 Filed: 2018-02-12

[97] Argument-in-chief, p. 54.

[98] The productivity indicator on the Team Scorecard was stated during the oral hearing as being on a corporate-wide, not distribution, basis. (Transcript, Vol. 2, p.99 L8 to L15)

In summary, based on the factors discussed above, OEB staff is not convinced that the scorecards provided by Hydro One and the targets and performance levels tied into these scorecards will provide Hydro One with adequate incentive during the 2018-2022 period to achieve outcomes for existing and future customers that appropriately reflect customer expectations by including factors such as cost control, system reliability, service quality and bill impacts. OEB staff therefore submits that the OEB in its Decision should direct Hydro One to propose more challenging targets than the ones it is presently suggesting in its Draft Rate Order submission or else explain why it is not possible for it to achieve such targets.

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

Background

Hydro One provided a number of different means for assessing its productivity in the application. As has already been discussed, its PSE study provided an assessment that can be used in assessing expectations for gains relative to external benchmarks. In addition, the Electricity Distributor Scorecard filed by Hydro One as part of the initial evidence[99] included some industry performance indicators for service quality and customer satisfaction indicators to which Hydro One's own targets could be compared.

Hydro One also included productivity gains in its forecasts. These were provided in the original evidence and then updated in response to an interrogatory as shown in the table below:[100]

$ millions

	2018	2019	2020	2021	2022	Total
Capital	36.4	34.2	37.8	37.3	39	184.7
OM&A	29.4	33.7	40.9	42.9	45.5	192.4
Corporate Common	4.0	4.2	4.2	4.2	4.2	20.8
Total	69.8	72.1	82.9	84.4	88.7	397.9

[99] Exh. A Tab 5, Sch 1, p. 8 Filed: 2017-03-31

[100] Exh B1-01-01 Sec 1.5, pp. 1966-1967 Filed: 2017-03-31 and Exh I, Tab 25, Sch. Staff-123, p. 2 Filed: 2018-02-12

Hydro One also provided a detailed breakdown of the individual projects that contributed to these totals and the amount of the savings expected to be generated from each of them.

Hydro One explained that the enhancements it had made to its productivity governance since the last application.[101]

> MR. LOPEZ: … so if I take a step back, Hydro One started their productivity push in late 2015, and we had made some strides forward in 2016, saving around $24 million in 2016, but it was still in its early infancy. In 2017 it is significantly larger, so we grew that $24 million to $118 million in that period of time. How we did that was by improving the governance, the transparency around productivity, how it's recorded, how it's tracked, how we hold people accountable, all the way from when we identified the initiative through to incentives, so it is linked to our team's scorecard, so people's pay is at risk if these targets are not met.
>
> Their budgets are adjusted. As soon as the productivity initiative is approved, their forecasts are reduced by those numbers, so now they're on the hook to deliver those outcomes.

OEB Staff Submission

OEB staff submits that it is not clear based on the information provided in the application that expectations for gains relative to external benchmarks are adequately included in the application, although OEB staff does acknowledge the challenges that exist in finding appropriate external benchmarks that are relevant to Hydro One. This matter has already been discussed extensively in previous sections of this submission.

[101] Transcript, Vol. 1, p. 103 L26 –p. 104, L13 as quoted in Argument-in-chief, p. 58

OEB staff is also not convinced that Hydro One has adequately accounted for productivity gains in its forecasts based on the information provided in the application discussed in this section of this submission. The major reason for this view is that the determination as to what constitutes a productivity gain as determined by Hydro One's approach appears to be very subjective.

This is for two reasons. First, it is not clear to OEB staff why some savings are productivity gains and others are not. Second, where headcount reductions are involved in these types of projects, it appears that these are often reductions in headcount on the project only with the reduced headcount going elsewhere in Hydro One rather than actual overall headcount reductions.

OEB staff explored these concerns with Hydro One at the oral hearing.

One of the projects included in Hydro One's forecast of productivity gains is telecom services contracts for which the measurement and expected benefit was described as "Lower Cost per Contract *Reflects negotiated reduction in contract price."*[102]

OEB staff asked Hydro One whether that meant that any negotiated reduction in a contract price would be considered a productivity improvement, or whether there would be particular reasons why this particular renegotiation would qualify and others might not. Hydro One responded as follows:

> "MR. LOPEZ: Yes. So just resulting in a lower price, if you also delivered a lower volume or a lower quality of service, that wouldn't be productivity. So sitting behind it, there would be other reasons why a lower price in some cases would get in here and a lower price on others wouldn't.
>
> If I'm at a lower price, but the quality of the service

[102] Staff-123, p. 2.

> failed or something was changed, then that again would not qualify as productivity."[103]

OEB staff submits that the various qualifications included at the end of Hydro One's response would lead to the conclusion that there is a significant element of qualitative judgement as to which negotiated reductions in contract prices would be considered as productivity improvements and which would not. OEB staff also notes that whether or not the quality of the service provided by the contract failed is something that could only be determined retroactively.

OEB staff had requested through an interrogatory[104] the detailed calculations that Hydro One had used to derive the productivity savings, but Hydro One did not provide these calculations. When asked during the oral hearing why this was the case, Hydro One responded that "We had interpreted the question to provide an outline or detailed outline of what makes up the productivity numbers. That is what we provided here."[105] OEB staff asked Hydro One if they could provide these calculations and it was agreed that Hydro One would provide them for three of the projects which were: (1) move to mobile, (2) procurement and (3) telematics.[106]

OEB staff notes that the calculations provided for the "Move to Mobile (Field Force)" project, which is one of the most significant projects included in the productivity savings forecast with projected savings annually in the $10 to $11 million range in the 2018 to 2022 period contains calculations that are significantly based on labour savings.[107] One challenge in determining labour savings for these types of projects is the question of whether a productivity gain is considered to arise only if there is an absolute reduction in Hydro One's overall FTEs, or whether a productivity gain is also considered to be the case even if there is only a reduction in the FTE level in the area of the project, with no overall reduction in FTEs but instead, staff are moved over to other areas of Hydro One.

[103] Transcript, Vol. 2, p. 54 L28 to p. 55 L8
[104] Staff-123.
[105] Transcript, Vol. 2, p. 41 L3 to L5.
[106] Undertaking J 2.3
[107] Undertaking J 2.3, p.3.

OEB staff asked Hydro One about this matter during the oral hearing and Hydro One responded as follows:[108]

> "MR. LOPEZ: It would have to be reflected in this case as a permanent reduction in that activity.
>
> MR. SIDLOFSKY: That is the only way it makes into the productivity calculation?
>
> MR. LOPEZ: Yes, if what you do is you re-deploy it. There could be a situation where another area could accept the reduction, they had a vacancy and a the person moved across to that vacancy. We would have hired from outside anyway, so that one potentially would count.
>
> But we've got to see an absolute reduction in heads for that activity. That has to occur."

OEB staff submits that this response appears to suggest that under Hydro One's approach, it would be possible to include avoided headcount increases and headcount reductions for a specific activity rather than absolute headcount reductions in assessed productivity savings. OEB staff is of the view that the extent of such savings is a far more subjective determination than absolute headcount reductions. This is in turn another indication of the subjectivity of Hydro One's overall approach to developing its productivity savings forecast.

As such, it is OEB's staff submission on this issue that because of the significant element of subjectivity in Hydro One's approach it is not sufficiently clear that the application adequately accounts for productivity gains in its forecasts.

OEB staff makes its submissions on the implications of this lack of clarity with respect to the nature of these savings in its submissions on the proposed capital program under Issue 30. OEB staff submits that Hydro One should be directed to clearly demonstrate in future applications how its claimed productivity savings achieve quantifiable cost savings

[108] Transcript, Vol. 2, p. 55 L18 to L28.

that will reduce costs for the distribution ratepayer (e.g. absolute headcount reductions that can be specifically related to the productivity initiative.

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?

Background

Hydro One stated that it is committed to managing within the revenue requirement proposed over the course of the custom incentive rate plan term in a reasonable and appropriate manner. Where the capital portion of the revenue requirement is concerned, Hydro One expressed its commitment to spending within the proposed amounts as it is at risk for capital overspending during the plan and will have to justify and In-Service Additions (ISA) over approved levels in the next application, while at the same time the CISVA protects against underspending.

Hydro One stated that its commitment to spend within the revenue requirement is also demonstrated by its historical spending as its capital spending over the course of the last rate period was approximately equal to the approved amount and its OM&A spending has been declining over the course of the last rate period to the point where it is meaningfully below approved levels.

Hydro One also noted that its productivity and savings forecast further demonstrates its commitment to manage its revenue requirement.

OEB Staff Submission

OEB staff has expressed its concerns about Hydro One’s productivity and savings forecast under Issue 21.

OEB staff is also concerned that while it is important that Hydro One manage within the revenue requirement, it is also important that Hydro One not request more cost recovery than it requires to do so. OEB staff notes in this context Hydro One’s comment above that its OM&A spending has been declining over the course of the last rate period to the point where it is meaningfully below approved levels. OEB staff discusses its concerns in this regard in more detail under Issue 38.

D: DISTRIBUTION SYSTEM PLAN

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

Background

Hydro One stated that its customer consultation process included formal customer engagement sessions, stakeholder engagement sessions, and ongoing discussion forums. Hydro One engaged a third-party research firm, Ipsos "to assist with the design, execution, documentation, and analysis of feedback for the customer engagement and engagement process[109]." With the help of Ipsos, Hydro One gathered information on customer needs and preferences through various outreach methods such as open link surveys and phone surveys. The customer consultation process concluded that cost is the top priority for residential and small business customers (and one of the top priorities for large customers), and that maintaining reliable electricity service was a secondary priority compared to cost.[110] Customers also expressed the view that Hydro One should maintain reliability and quality at current levels.[111]

Hydro One also stated that during the consultation process, customers were also presented with directionally indicative reliability outcomes such as, reduced, maintained, or improved reliability, rather than measurable reliability outcomes. This was coupled with specific capital expenditure forecasts, to which Hydro One connected these directionally indicative reliability outcomes.

As part of its investment planning process, Hydro One developed four different investment scenarios, Plans A, B, C and B-Modified, each of which was expected to deliver different reliability performance outcomes. Hydro One's projected reliability performance outcomes were based upon the projected impact of poles, stations, other line components, and vegetation management on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) by the year 2022.[112]

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[109] Exh. B1-1-1, DSP Sec. 1.3, p.4 Filed 2017-03-31.

[110] EB-2017-0049, Exhibit B1-1-1, DSP Section 1.3, page 16 of 21.

[111] EB-2017-0049, Exhibit B1-1-1, DSP Section 1.3, page 16 of 21.

[112] EB 2017-0049, Exhibit B1-1-1, DSP Section 2.4.

The expected reliability performance outcomes for SAIDI and SAIFI for the four scenarios are shown in the two tables below:

SAIDI[113]

SAIDI[1]:	Avg. 2012-16: 7.3 hours/year	Average Number of Hours a Customer is Interrupted					
	Assumptions			Forecasted Impact on SAIDI by 2022[2]			
	Failure Rate/Impact	Contribution to SAIDI	SAIDI Contribution (based on 2012-16)	Plan A	Plan B	Plan C	Plan B-M[3]
Poles	• 0.3k outages/year • 0.4k customers/outage • 5 hours/outage	6%	0.4	12%	10%	(18)%	7%
Stations	• 0.1k outages/year • 0.9k customers/outage • 3 hours/outage	2%	0.2	14%	5%	(4)%	0%
Other Line Components	• 7k outages/year • 0.1k customers/outage • 3 hours/outage	21%	1.6	10%	0%	(10)%	(5)%
Vegetation	• 7k outages/year	31%	2.3	8%	8%	4%	8%
Estimated Impact to SAIDI				6%	3%	-2%	2%
Forecasted SAIDI (hours)				6.9	7.1	7.4	7.2

1-Excludes force majure and loss of supply event
2-These columns reflect the forecasted impact on SAIDI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
These forecasted impact do not include changes based on the new vegetation management strategy as the data set is incompatible
3-Impacts for "Plan B-M" refer to Plan "B-Modified"

113 EB-2017-0049, Exhibit I, Tab 18, Schedule EnergyProbe-17.

SAIFI[114]

SAIFI [1]**:**	**Avg. 2013-15: 2.6 outages/year**	**Average Number of Times a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIFI by 2022** [2]			
	Failure Rate/Impact	**Contribution to SAIFI**	**SAIFI Contribution** (based on 2013-15)	**Plan A**	**Plan B**	**Plan C**	**Plan B-M** [3]
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	12%	10%	(18)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0-1%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.7**	**2.6**

1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIFI by then end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3 – Impacts for "Plan B-M" refer to Plan "B-Modified" described earlier in this Section.

The system reliability is the total weighted reliability impacts of the four programs based on the expected performance improvement in each program for each plan. For example, under Plan B-Modified, poles will have a 6% contribution to SAIDI x 7% forecast impact = 0.4% system SAIDI improvement.

The forecasted SAIDI and SAIFI impacts for each program are calculated separately based on the forecasted SAIDI and SAIFI impact of different levels of asset replacement on the overall fleet condition. For poles, Hydro One assumed that maintaining a level of 106,000 poles in need of replacement over the forecast period would keep reliability at a *status quo* level. As the number of poles in need of replacement increased or decreased based on different levels of planned pole replacements over the forecast period, the reliability impact was prorated on a linear basis as shown in the table below.[115]

[114] EB-2017-0049, Exhibit B1-1-1, DSP Section 2.4, page 7 of 8.
[115] EB 2017-0049, Exhibit I, Tab 29, Schedule Staff-164; Oral Hearing Volume 9, pages 40-41.

Reliability Impact - Poles

	Wood Poles in need of replacement (k)	Calculation	Change in Fleet Condition	Reliability Impact Shown (Tables 52-53)
Current	106	-	-	-
Plan A	93	1 – (93/106)	12.3%	12%
Plan B	96	1 – (96/106)	9.4%	10%
Plan C	126	1 – (126/106)	(18.9)%	(18)%
Plan B-Modified	99	1 – (99/106)	6.6%	7%

For stations, Hydro One assumed that maintaining a level of 70 stations in need of replacement over the forecast period would keep reliability at a status quo level, and that eliminating all stations in poor condition would lead to a 9%[116] improvement in station-related reliability. As the number of stations in need of replacement increased or decreased based on different levels of planned station refurbishments, the reliability impact was prorated against the assumed 9% improvement as shown in the table below.[117]

Reliability Impact - Stations

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

For other line components, Hydro One assumed that maintaining a level of 300,000 defects in need of replacement over the forecast period would keep reliability at a status quo level. As the number of defects in need of replacement increased or decreased

[116] Please note that Hydro One's original calculation assumed that eliminating 70 stations in poor condition would lead to a 14% improvement in station-related reliability, which was later changed to 9%. The SAIDI and SAIFI tables above have not been updated to reflect this change.
[117] EB-2017-0049, Exhibit JT 3.10; Oral Hearing Volume 9, pages 45-46

based on different levels of defects being addressed, the reliability impact was prorated accordingly as shown in the table below.[118]

Reliability Impact – Other Line Components

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

For vegetation management, Hydro One assumed that maintaining a level of 104,000 km of rights of way (RoW) classified as low or medium-priority over the forecast period would keep reliability at a status quo level. Under each plan, Hydro One assumed that reallocating 1,000 km/year of maintenance on low or medium-priority RoWs to high-priority RoWs would lead to a 9% improvement in reliability. The reliability improvements associated with increased maintenance on high priority RoWs is partially offset by reliability degradation resulting from the reduction in maintenance on the low or medium-priority RoWs as shown in the following table.[119]

[118] EB-2017-0049, Exhibit JT 3.10; Oral Hearing Volume 9, pages 47-48

[119] EB-2017-0049, Exhibit JT 3.10; Oral Hearing Volume 9, pages 48-50.

Reliability Impact – Vegetation Management[120]

	Kilometers of Low/Med. Priority RoW Maintenance, (k)	Calculation	Relative Change in Low/Med RoW Maintenance by Option*	Impact to Reliability**	Combined Relative Change in Reliability Impact
Current	104	-	-	-	-
Plan A	103	(103/104)-1	-1.0%	9%	8.0%
Plan B	103	(103/104)-1	-1.0%	9%	8.0%
Plan C	99	(99/104)-1	-4.8%	9%	4.0%
Plan B-Modified	103	(103/104)-1	-1.0%	9%	8.0%

** The net change is then assumed to reflect a potential improvement or deterioration in reliability*
*** Based on vegetation management feeder model impact on reliability*

OEB Staff Submission

OEB staff submits that Hydro One's customer consultation on the DSP was inadequate as it did not establish a clear enough relationship between the reliability/cost tradeoff that customers were prepared to accept. This is because as the reliability outcomes were only indicative, customers were not able to comment on a quantifiable relationship between the increases in system reliability and the associated level of capital spending.

With respect to the adequacy of the DSP to address customer needs and preferences, OEB staff submits that Hydro One's current level of capital spending does not adequately address customer needs and preferences as it does not take into account the potential impact on reliability of the new vegetation management strategy that was introduced during the course of the application review process and well after the DSP had been finalized.

OEB staff notes that Hydro One had stated the originally filed Plan B-Modified detailed in the DSP was chosen because it represented the minimum possible rate increase required to hold reliability performance constant over the planning period.[121] However,

[120] EB-2017-0049, Undertaking J 6.01.01.
[121] EB 2017-0049, Exhibit B1-1-1, DSP Section 2.4, page 1 of 8.

the new vegetation management strategy is expected to improve overall system reliability performance over the five year forecast period by 20-40% for the same vegetation management costs.[122]

During the oral hearing, Hydro One was asked whether the new vegetation management strategy would result in any reductions in its capital spending program, Hydro One stated that:

> "The plan that we have is based on achieving a balanced set of outcomes. So we've used the OEB's Renewed Regulatory Framework that focuses on customers, operational effectiveness, public policy responsiveness, and financial performance. It isn't only reliability that drives our investments; it is sustaining our fleet of assets."[123]

Hydro One stated in its argument-in-chief under Issue 38 that the vegetation management program does not renew assets in need of replacement.[124] Hydro One further stated that its view was that the primary driver for Plan B Modified is being able to sustain the fleet of assets and not enable them to deteriorate.[125] OEB staff acknowledges the importance of sustaining the fleet of assets but notes that a key outcome of fleet deterioration is poorer system reliability. As the condition of assets deteriorates the risk of asset failure increases, and thereby poorer reliability. OEB staff submits that Hydro One's calculations for Plan B Modified described above already includes the consideration of different levels of deteriorating fleet.

OEB staff does not dispute the importance of meeting system and assets needs, however Hydro One's fundamental premise in developing Plan B-Modified was to minimize rates while holding reliability constant. Hydro One's own calculation has shown a linear relationship between program spending and reliability, which was based on Hydro One's fleet of poles, stations, other line components, and vegetation. By this same approach, an increase in reliability in one area could correspondingly be offset by a decrease in reliability in another and thereby reducing capital spending while maintaining status quo reliability over the planning period.

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[122] EB 2017-0049, Exhibit Q-1-1, Attachment 2, page 4.
[123] Oral Hearing, Volume 9, page 52, lines 13-19
[124] Argument-in-chief, page 123
[125] Argument-in-chief, page 123

As such, OEB staff is concerned that since the customer consultation shows that minimizing costs and keeping rates as low as possible is the top customer priority, and existing system reliability levels are acceptable and do not need to be improved, Hydro One's current level of capital spending does not adequately address customer needs and preferences as it does not take into the impacts of the new vegetation management strategy. OEB staff submits that Hydro One should reduce its overall system renewal capital expenditures to reflect the reliability improvements from the vegetation management strategy, such that reliability levels are maintained at *status quo*. This will be expanded further under Issue 30 below.

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?**

Background

Hydro One stated that it uses a bottom-up approach to identify candidate investments to address asset conditions that impose risk upon the system,[126] and uses defined probability and consequence evaluation criteria[127] to determine the pre and post risk exposure associated with different candidate investments. Subsequent to the pre and post investment risk assessment, the portfolio of candidate investments is evaluated for risk consistency in a "calibration session".[128]

After the risk assessment and calibration session, projects are then prioritized into a list using a risk-based asset management tool (i.e. the Copperleaf Tool). At the technical conference, Hydro One confirmed that the Copperleaf Tool is used to develop a portfolio of prioritized projects, and that subsequent to this risk assessment and investment optimization process another calibration session is held where Hydro One management is able to override the portfolio of optimized projects developed using the Copperleaf tool.[129]

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[126] Technical Conference, March 5, 2018, pages 120-121

[127] EB-2017-0049, Exhibit I, Tab 24, Schedule Staff 89, Appendix A and Appendix B.

[128] EB-2017-0049, Exhibit B1-1-1 DSP Section 2.1, page 25 of 34; and Oral Hearing Volume 9, page 101, lines 19-27.

[129] Technical Conference, March 2, 2018, page 43-44.

Hydro One stated at the technical conference that there is no capital spending target set from an investment planning point of view and that its planners are focused strictly on a bottom-up approach to identify the needs of the system.[130] However, Hydro One further stated that through this bottom-up process, planners identified that the current health of the assets requires a higher level of investment than customers can afford, and that a financial constraint was put on the optimizer to determine the maximum amount of risk that can be mitigated with the dollars defined by the constraint.[131]

Hydro One further clarified that the financial constraint (i.e. a top down spending envelope[132]) is informed by previous business plans (i.e. based on how much was previously spent), and is adjusted based on what needs to be done going forward.[133]

OEB Staff Submission

OEB staff notes that although Hydro One provided presentations given at the risk calibration sessions, it has not provided formalized documentation on the calibrations made and the reasons behind it.[134] As a result it is not clear, when the sessions occur in the project portfolio optimization process, what evaluation criteria the calibration sessions use; what outcomes the calibration sessions are intended to produce; how significantly the optimized project portfolio is modified during these calibration sessions; and what is the resulting impact on the capital investment budget filed as Plan B-Modified. As a result, OEB staff submits that it is not clear how Hydro One's final list of projects to be undertaken is risk optimized.

OEB staff is concerned that Hydro One's pre-defined financial constraints indicate that overall budget envelopes are top down budgets developed based on previous business plans which are then adjusted and filled with prioritized projects until all the available funding is allocated.

OEB staff submits that setting pre-defined financial constraints is contradictory to Hydro One's claimed bottom-up approach since the spending envelope constrains the amount of money to be spent. The individual risk assessments for candidate investments have

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[130] Technical Conference, March 5, 2018, pages 120-121

[131] Oral Hearing, Volume 9, page 62, lines 5-11.

[132] Oral Hearing, Volume 9, page 66, lines 3-6.

[133] Oral Hearing, volume 8, pages 52-53.

[134] JT 2.9

no bearing on the overall capital spending envelope but instead are competing within a predefined capital spending envelope based on what was previously approved. OEB staff is of the view that the case record does not adequately demonstrate that Plan B-Modified was developed by building an optimized bottom-up project portfolio that would simultaneously maintain historical reliability performance and fill the pre-determined spending envelope.

OEB staff submits that it is not clear that the actual investment planning process considers the appropriate planning criteria to adequately address the interlinkages between the condition of distribution assets, service quality and system reliability. In the absence of such linkages, a reasonable approach to forecasted capital spending would be to use the historical five-year average.

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

Background

Hydro One stated that productivity gains had been addressed in Section 1.4 of the DSP with additional productivity updates filed as part of its Exhibit Q update in December 2017. Hydro One also referred its $398 million of productivity savings that have been reflected in the DSP and that are discussed in detail under Issue 21 of this submission. Hydro One stated that its capital productivity initiatives have reduced the capital budget for which it is seeking approval and submitted that this result strongly supports its commitment to finding better ways to become more productive and efficient and addressing past concerns raised in prior decisions and concerns heard from customers.

Hydro One stated that the application reflected benefit sharing through the productivity initiatives discussed above, and through the ESM which is discussed under Issue 15.

With respect to benchmarking, Hydro One stated that the DSP reflects this through the reports of Navigant, CN Utility and Gartner. These reports are discussed in more detail under Issue 10. Hydro One further noted that following the preparation of the DSP, it had continued its efforts to improve its long-standing vegetation management program following review of the CN Utility report through the commissioning of the Clear Path report that was filed as part of its December 2017 update and which is discussed in numerous sections of this submission.[135]

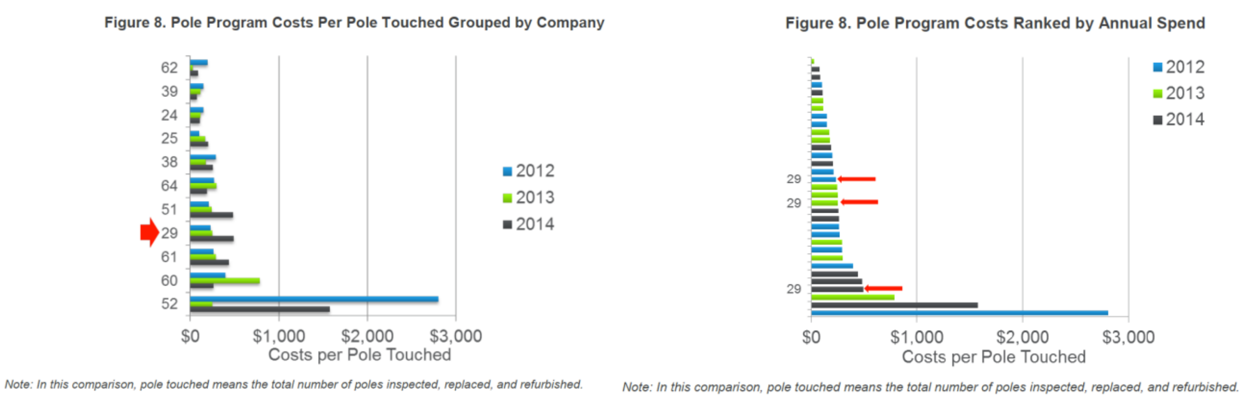
OEB Staff Submission

OEB staff has already discussed its concerns that the DSP does not adequately reflect productivity gains, benefit sharing and benchmarking with respect to the Clear Path vegetation management report under Issue 23.

OEB staff also has concerns related to Hydro One's performance in the area of Hydro One's pole program costs. OEB staff notes that as part of the pole replacement and distribution station refurbishment program study, Navigant, which had been retained by Hydro One to conduct a benchmarking study for its pole and station management programs, provided two figures showing Hydro One's pole program per pole touched costs (this includes inspection, refurbishment, or replacement) and pole program costs relative to its peers.[136]

OEB staff submits that this study included tables showing that Hydro One is ranked in the bottom quartile when compared to its peers in terms of pole program costs, as is shown in the tables below where Hydro One is identified as company #29:

Pole Program Costs Ranked Per Pole Touched and by Annual Spend



The data in the above tables shows that, in a group of comparable companies selected by Navigant, Hydro One ranks 10th of 11 companies in terms of pole program costs per pole touched (the table on the left) and by annual spend in 2014 (the table on the right).

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135 Argument-in-chief, pp.73-76.

136 EB-2017-0049, Exhibit B1-1-1, DSP Section 1.6, Attachment 1, page 8.

Furthermore, during cross-examination, Navigant confirmed that Hydro One's costs would be ranked lower if an outlier company (ranked 11th of 11 companies) were excluded from the analysis.[137]

OEB staff submits that the concerns raised above, coupled with those that OEB staff has raised under Issue 21 with respect to Hydro One's productivity savings, call into question the extent to which the DSP adequately reflects productivity gains, benefit sharing and benchmarking and would suggest that a reduction in the approved revenue requirement level related to capital expenditures is necessary to reflect the insufficiency of the productivity gains incorporated into the application and to incent Hydro One to do better in the future.

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

Background

Hydro One stated that the DSP addresses the trade-offs between capital and OM&A spending over the course of the plan period through processes and procedures in place to make the appropriate trade-offs between capital and OM&A. Hydro One further stated that it has a detailed Asset Analytics: Asset Maintain – Refurbishment/Repair – Repair Economic Evaluation Model that explains how it makes refurbishment, repair and replace decisions and that this model allows Hydro One to make appropriate decisions about when to repair or replace distribution assets, where possible. Hydro One also noted that when future OM&A costs are impacted by a capital expenditure they are considered when building the capital investment plan.

Hydro One also noted, however, that much of its distribution business cannot make trade-offs between capital and OM&A due to the nature of the work programs, projects or OM&A expenses that are required. Hydro One submitted that fundamentally therefore, the best evidence of its approach to the trade-offs between capital and OM&A spending is the bottom up approach to the development of the application, as reflected through the investment planning process.[138]

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[137] Transcript, Vol.6, pages 84-85.
[138] Argument-in-chief, p. 83

Hydro One stated that there is no artificial balancing or reweighing of capital or OM&A at the top line level, rather the capital and OM&A spending levels reflect the culmination of the individual planning decisions made by Hydro One.

Hydro One cited the vegetation management program as its largest OM&A expense, for which there is no opportunity to spend capital to eliminate the need for these expenditures as an example of the limitations of these trade-offs. Hydro One further noted that much of the remainder of the OM&A expenses are for “demand” programs required for compliance reasons which cannot be addressed through capital expenditures. Hydro One cited the “Trouble Calls” Lines Sustaining OM&A program, with an estimated 2018 cost of $77.9 million, as a demand program where it does not have an opportunity to trade-off with capital.[139]

OEB Staff Submission

OEB staff acknowledges the limitations that Hydro One points out regarding the potential for trade-offs between capital and OM&A spending. OEB staff is satisfied that the DSP adequately addresses trade-offs given such limitations, subject to the concerns OEB staff expresses about Hydro One’s investment planning processes under Issue 24 and that the DSP did not incorporate the effects of the new vegetation management policy as discussed under Issue 23.

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

Background

Hydro One submitted that the DSP had adequately addressed government mandated obligations, specifically because of the following considerations:[140]

- The DSP reflects Hydro One’s government mandated obligation to install smart meters
- The DSP reflects the requirement to address PCB equipment

[139] Argument-in-chief, pp. 83-84.

[140] Argument-in-chief, pp. 85-86

Hydro One identified the capital costs associated with carrying out its government mandated obligations. Examples of mandated obligations which Hydro One has accounted for in its application are listed below:[141]

Investment Category	Mandated Obligations
System Access	• SA-02: Metering Infrastructure Sustainment Program • SA-03: Meter Infrastructure Expansion Program • SA-04: New Load Connections, Upgrades, Cancellations and Metering • SA-05: Distributed Generation Connections
System Renewal	• SR-01: Distribution Stations Demand Capital Program • SR-08: Distribution Lines PCB Equipment Replacement Program • SR-14: Advanced Meter Infrastructure Hardware Refresh
System Service	• SS-02: System Upgrades Driven by Load Growth • SS-05: Distribution System Modifications

OEB Staff Submission

OEB staff has no issues with Hydro One's evidence on the above-referenced projects and programs, and submits that Hydro One has adequately allowed for costs to carry out its government mandated obligations.

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

Background

The Regional Planning process undertaken by Hydro One identifies capital expenditure investments that are required to meet regional needs. Hydro One's Regional Planning process is described in Section 1.2 of the DSP, and examples of Regional Planning reports are provided in attachments 3 through 30 of DSP Section 1.2.[142]

[141] Exh B1-1-1, Sec. 3.7, pp. 1-3 Filed 2017-03-31.
[142] EB-2017-0049, Exhibit B1-1-1, DSP Section 1.2.

OEB Staff Submission

OEB staff has no issues with Hydro One's evidence on the above-referenced areas and submits that Hydro One has appropriately conducted Regional Planning activities and incorporated the resulting capital investment considerations in its DSP.

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

Background

Hydro One submitted that the proposed capital expenditures resulting from the DSP are appropriate and have been adequately planned and paced. Hydro One argued that fundamentally, the appropriateness of its proposed capital expenditures is demonstrated through its development of the DSP as outlined in response to Issues 23 to 29 and the subsequent discussion of the specific capital expenditures in response to Issue 30.

Hydro One reiterated that it took a bottom up approach to the identification of needs and the development of solutions and had used appropriate planning criteria to optimize the plan. Hydro One stated that the level of spending was arrived at after an iterative process whereby customer consultation and the incorporation of customer needs and preferences were a key component, while at the same time considering the condition of its assets while formulating its plan. Hydro One stated that the result was that it had selected the capital investment plan that allows for the lowest possible rate impact while maintaining the condition of its assets.

Hydro One discussed four specific planning and pacing matters, which are summarized below:[143]

1. *Improvements to the Asset Planning Process since the last Application*

In its last decision[144] the OEB found that Hydro One's DSP was difficult to follow when the DSP components were not consolidated and did not demonstrate that the capital expenditure plan was optimized. The OEB directed Hydro One, in its next application, to provide a consolidated plan that shows the process that led to an optimized DSP and the

[143] Argument-in-chief, pp. 87-96
[144] EB-2013-0416

corresponding capital investment program. The OEB also expected Hydro One to have its DSP reviewed by an independent third party.

In this application, Hydro One engaged AESI Inc. (AESI) to review and comment upon the suitability and compliance of the Hydro One DSP.[145] AESI confirmed that the DSP satisfied the *OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements*.[146] Hydro One's argument-in-chief states that it believes that the AESI review satisfies the OEB's direction for an independent third party review and that the current DSP addresses all prior shortfalls and reflects improvement in both its organization and content.

Hydro One stated that it has made significant improvements to its investment planning process since its previous distribution rates application, which have focused on addressing customer needs and preferences in the investment management processes. Hydro One further stated that these matters are now central to the investment planning process and the task of finding an appropriate balance to address these needs as well as the needs associated with distribution asset condition and system reliability.

2. Data Quality and Completeness

Hydro One noted that its Asset Management Panel was cross-examined on certain statements from the Auditor General (AG) and Hydro One's follow-up internal audits concerning data quality and completeness issues. Hydro One argued that the issues raised by the AG did not concern the quality of the data, but the asset analytic tools being used. Hydro One submitted that it has the asset condition data it needs to make prudent planning decisions and stated that it is continuing to improve its asset analytics tool in order to aggregate data for its planners, but there is no gap or missing information that would cause Hydro One to overinvest in capital projects. Hydro One stated that to the contrary, if there is missing data, which it does not believe there is, then the planned spending is lower than it otherwise should be.

[145] EB-2017-0049, Exhibit B1-1-1, DSP Section 1.0, page 14 of 15
[146] EB-2017-0049, Exhibit B1-1-2

3. Redirection

Hydro One stated that redirection is an important part of its asset planning process and embedded in the DSP. Furthermore, it explains why historical investments do not align perfectly with previously proposed plans and why in the future, Hydro One's investments will not align perfectly with the currently proposed plan. Hydro One outlined this process in the DSP and further explained it during the oral hearing:[147]

> MS. GARZOUZI: So redirection is actually an activity that occurs monthly. So we look at our programs and projects for OM&A, ISA, and capital on a monthly basis, and we look at emerging needs, if they do exist, and we reprioritize via the redirection process.

4. Investment Pacing

Hydro One stated that the level of investment spending was determined through the planning process described in response to Issues 23 to 29 and included consideration of customer needs and preferences, asset condition and system reliability. Hydro One submitted that as a result of that process, it had selected an investment plan – Plan B-Modified- that has the lowest possible level of capital spending, while still maintaining the condition of Hydro One's assets.

OEB Staff Submission

OEB staff has discussed its concerns with Hydro One's investment pacing in its submissions on Issues 23 to 28. As OEB staff has also noted previously, it is of the view that additional improvements to the asset planning process are also necessary.

There has been improvement in the current DSP compared to the last DSP and the OEB's expectation of an independent third party review has been met. The current DSP is a stand-alone document that has followed the format recommended in the chapter 5 filing requirements and has been reviewed by AESI for conformity.

[147] Transcript, Vol. 9, p. 74, L1 –L5.

However, OEB staff notes that in Hydro One's last DSP the OEB found the links between its asset management process and capital expenditure plan difficult to follow., OEB staff submits that the link between expected reliability outcomes under Hydro One's proposed plans and the respective related capital expenditure plans is still not clear. Each plan involves different levels of expenditure in each of four main programs: poles replacement, stations refurbishment, line component replacement, and vegetation management; yet Hydro One's overall capital envelope also includes many other capital projects outside of these four programs which appear to be held constant under all four plans.

It is also unclear if the overall capital envelope was developed based on a bottom-up approach where projects are selected to achieve the minimum risk tolerance threshold that Hydro One is willing to accept, or a top-down approach where the overall capital envelope is predefined based on expenditure trends approved in prior applications. OEB staff pursued this issue through interrogatories[148], the technical conference[149], undertakings[150], and the oral hearing[151] but was unable to find a clearer understanding. OEB staff submits that although Hydro One's DSP has improved, there remain areas for improvement in justifying its overall capital expenditures, as discussed in the other issues.

OEB staff also has concerns about the statements made by the AG that were discussed during the oral hearing.[152, 153, 154] In staff's view the availability of data is as important as its completeness, and concerns that the AG expressed raise issues regarding the appropriate availability of data on a timely basis such that optimal decisions can be made.. Hydro One suggests[155] that this would not result in assets being replaced early, but there may be assets which should be replaced, which are not, due to missing data. However, OEB staff is concerned that if one asset is not replaced because of missing data, it may lead to another asset being replaced earlier than would otherwise be the

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[148] EB-2017-0049, Exhibit I-24-Staff-89; Exhibit I-24-Staff-99; Exhibit I-24-AMPCO-1; Exhibit I-3-SEC-4.
[149] Technical Conference, March 2, 2018, pages 67-74; Technical Conference, March 5, 2018, pages 119-124.
[150] EB-2017-0049, Exhibit JT 2.10.
[151] Transcript, Volume 9, pages 57-66; transcript, Volume 8, pages 51-57.
[152] Recommendation #5 and #11 of the AG Report are discussed at: Transcript, Volume 1, pages 135-142
[153] Recommendation #5 of the AG Report is discussed at: Transcript, Volume 7, pages 34-41
[154] Recommendation #11 of the AG Report discussed at: Transcript, Volume 7, pages 41-62
[155] Argument-in-chief, p. 92.

case due to the availability of the funding that would have been used on the asset which would have been replaced, but for the missing data.

OEB staff also has concerns with respect to Hydro One's use of redirection. These redirection activities lead to plans being modified throughout the forecast period as a result of funds being reallocated to other projects and/or programs.

OEB staff notes that historically, Hydro One has had relatively stable SAIDI and SAIFI trends even though it has deferred prioritized projects that were deemed to be required in the last DSP. OEB staff submits that this demonstrates that actual past spending trends have been adequate to maintain reliability performance and that the Hydro One has the capability to withstand a certain level of project deferrals.

As an illustration of this, OEB staff notes that approximately 40% of projects planned within six specific investment drivers were deferred from Hydro One's previous distribution rate filing in favour of unforeseen investments, and those deferred projects are repeated in the current application.[156]

In the current application, the total budget associated with these six specific investment drivers amounts to $730 million over the planning period, representing approximately 20%[157] of the total capital expenditure:

[156] Oral Hearing, Volume 9, pages 69-80.

[157] Budget associated with deferred projects is $730 M, and the total capital expenditure is $3,571 M. Therefore, $730 M / $3,571 M = 20%.

Capital Expenditures associated with 6 Example Drivers[158]

Investment Driver	Forecast Capital Expenditures ($ M)					TOTAL ($ M)
	2018	2019	2020	2021	2022	
SR-06 Station Refurbishment	15.0	29.6	33.8	34.5	35.2	148.1
SR-08 PCB Equipment Replacement	11.6	11.8	12.1	18.5	18.9	72.9
SR-12 Distribution Lines Sustainment	22.3	31.1	30.9	33.8	33.7	151.8
SR-13 Life Cycle Optimization	20.5	27.1	22.4	29.0	34.9	133.9
SS-02: System Upgrades Driven by Load Growth	40.4	51.4	42.9	32.7	22.6	190.0
SS-03 Reliability Improvements	4.6	7.0	6.3	7.2	8.1	33.2
					Subtotal	**730**
					Total Capital Expenditure	**3,571**

Correspondingly, the pool of potential deferred projects within these investment drivers represents approximately 8% of the total capital project portfolio (40% previously deferred projects * 20% of total capital expenditure = 8% of the current capital project portfolio).

However, OEB staff notes that this value is based solely on deferrals within the six investment drivers discussed above, and the actual proportion of deferred past projects reappearing in the current application portfolio could be larger.

In the oral hearing, Hydro One was asked if there were any negative consequences to reliability associated with these project deferrals. Hydro One noted that it does not track reliability performance in that fashion but on a macro level, the SAIDI target for 2017 was 7.5 hours, but the actual SAIDI was 7.95 hours and was largely due to tree-related outages.[159]

OEB staff notes that it does not appear there are negative consequences to SAIDI in this case, when capital projects are deferred.

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[158] EB-2017-0049, Exhibit B1-1-1, DSP Section 3.7.
[159] Oral Hearing, Volume 9, page 76-77.

In addition, Hydro One's SAIDI and SAIFI performance trends have been relatively stable over the historical period[160,161] (adjusted to exclude force majeure weather events)[162], which reflect the actual performance as experienced by customers. This further supports the view that Hydro One's pattern of deferring prioritized projects has not triggered a significant negative impact on system performance reliability.

In summary, OEB staff observes that Hydro One has shown it is capable of deferring capital projects, which were stated as necessary in the previous cost of service application, without jeopardizing system reliability.

OEB staff therefore submits that based on historical actuals, Hydro One has the capability to further reduce capital spending from Plan B-Modified and still keep reliability *status quo*.

OEB staff also submits with respect to the matter of redirection that Hydro One should in addition to the above recommendations, for its next rebasing application, undertake a comprehensive review of its proposed capital project portfolio, adjusted as per the OEB's decision to identify the following:

- Which projects were completed as shown in the forecast
- Actual versus estimated cost of each project at completion
- Which projects were deferred or eliminated
- Reasons for deferral or elimination
- Consequences of each deferral or elimination

[160] EB 2017-0049, Exhibit B1-1-1, DSP Section 1.4, Table 10 – Historical SAIDI Summary, page 21 of 43.
[161] EB 2017-0049, Exhibit B1-1-1, DSP Section 1.4, Table 11 – Historical SAIFI Summary, page 22 of 43.
[162] OEB staff acknowledges that unexpected force majeure events do explain some of the project deferrals being discussed, however, it is the regularity of Hydro One's project deferral pattern that is of concern, despite the force majeure events which happen from time to time.

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

Background

Hydro One's DSP describes its system investment decisions for the years 2018 to 2022, and sets out its asset management and capital expenditure planning processes. **Error! Reference source not found.** below summarizes capital expenditures by category for the five-year historical period (2013 - 2017), and the five-year forecast period (2018 - 2022).[163] Based on actuals for the historical period, the average capital expenditures is $647 million. Hydro One's proposed capital expenditures average $714.7 million, an increase of 10.5%.

	Hydro One Networks Inc. - Capital Expenditure Summary $ millions									
	2013A	**2014A**	**2015A**	**2016A**	**2017B**	**2018F**	**2019F**	**2020F**	**2021F**	**2022F**
Category										
System Access	159.5	199.4	188.1	182.7	181.9	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	308.4	288.3	214.3	248.6	318.7	336.7	362.5	451.1
System Service	80.4	71.0	69.8	78.9	80.1	81.8	93.4	85.6	78.8	69.5
General Plant	131.4	114.4	112.0	144.3	101.6	143.3	168.5	116.2	103.7	105.9
Total Capital	**637.0**	**647.5**	**678.3**	**694.2**	**577.9**	**628.3**	**738.2**	**699.4**	**710.9**	**796.5**

A=Actual
B=Bridge
F=Forecast

As shown in the table below, the allocation of overall capital expenditures between the categories over the forecast period (2018 - 2022) remains similar to the bridge and historical (2013-2017) allocation ratios.

[163] EB-2017-0049, Exhibit Q-1-1, page 7 of 25; EB-2017-0049, Exhibit I, Tab 24, Schedule SEC-38 (Updated June 12, 2018).

Average Capital Expenditure and Investment Percentage by Category

Category	5- Year Bridge & Historic Actual Expenditures		5 - Year Forecast Expenditures	
	Average Expenditures ($ M)	% of Total Expenditure	Average Expenditures ($ M)	% of Total Expenditure
System Access	182.3	28%	161.8	23%
System Renewal	267.9	41%	343.5	48%
System Service	76.0	12%	81.8	11%
General Plant	120.7	19%	127.5	18%
Total Capital	**647.0**	**100%**	**714.7**	**100%**

System Renewal Expenditures

OEB staff notes that consistent with the historical distribution of capital expenditures, system renewal expenditures comprise nearly half of Hydro One's planned investments, representing 48% of capital expenditures over the forecast period.

System renewal expenditures are mainly driven by a pole replacement program, a trouble call and storm damage response program, lines sustainment initiatives and distribution station refurbishments. OEB staff addresses pole replacement and station refurbishment below, however does not specifically address trouble call and storm damage response as these programs are relatively less material.

OEB staff's submissions on Hydro One's system renewal expenditures are made under three subsections: (i) Pole Replacement Program, (ii) Distribution Station Refurbishments and (iii) general considerations.

(i) Pole Replacement Program

Background

With a total capital budget of $579 million over the five-year forecast period, the pole replacement program (ISD SR-09) represents the largest investment in the system renewal category.[164] Hydro One's proposed pole replacement program under Plan B-Modified will replace a total of 72,000 poor condition poles over the five year period,

[164] EB 2017-0049, Exhibit B1-1-1, DSP Section 3.7, page 2 of 11.

which is Hydro One's anticipated replacement pace necessary to keep the population of poor condition poles approximately constant over the planning period.[165] Therefore, the forecast number of pole replacements and associated spending proposed represents the level of spending and replacement required under Plan B-Modified to hold reliability constant over the forecast period.

Hydro One noted that an estimated 12,000 additional poles are replaced each year for other reasons,[166] the costs of which would fall under various other programs.[167] This amounts to an additional 60,000 poles being replaced over the planning period in addition to the 72,000 already being replaced, for a total of 132,000 poles replaced over the planning period.

OEB Staff Submission

OEB staff notes that although the exact percentage of poor condition poles replaced as part of the 12,000 additional replacements per year is unclear, based on the description of each program, it is reasonable to expect some overlap between the poles replaced in other programs and poor condition poles. Poles are replaced under storm conditions and Hydro One confirmed that poor condition poles are more susceptible to failure than are poles in better condition under storm conditions. In addition, entire sections of feeders can be addressed due to the deterioration of distribution line assets, one of which is poles. It is also worth noting that when feeders are upgraded, poles can also be replaced as part of these projects.

Hydro One pointed out that the DSP maintained the condition of assets and reliability of the system.[168] However, the above evidence indicates that Hydro One will replace more poor condition poles than necessary to maintain system reliability *status quo*.

OEB staff submits that Hydro One's pacing of the pole replacement program should be reduced to a level consistent with maintaining constant overall system reliability and a consistent population of poor condition poles.

[165] EB 2017-0049, Exhibit J 7.3. Pages 1-3.
[166] Technical Conference, page 164, lines 13-14.
[167] These include SA-01 joint use and line relocations, SR-07 distribution line trouble calls and storm damage, SR-12 distribution line sustainment, SR-13 life cycle operational efficiency, and SS-02 system upgrades as discussed in Transcript Vol. 9, p. 90 L1 –L23
[168] Oral Hearing, Volume 9, page 55, lines 19-23.

OEB staff also notes that there may be refurbishment opportunities which would mitigate the need for replacements. Hydro One stated that approximately 14% (or 10,000 poles)[169] of the poor condition poles being targeted for replacement would be good candidates for structural refurbishment.[170]

Furthermore, the Navigant benchmarking study stated that "The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately seven times more expensive where refurbishment is an option."[171]

OEB staff submits that this indicates that approximately 14% of poles being replaced can be structurally refurbished for a fraction of the replacement cost.

OEB staff notes in this context Hydro One's explanation that any potential cost benefit from refurbishment would be reinvested in the pool of the other poor condition poles in need of replacement,[172] which would further improve reliability above the improved levels already anticipated.

Consequently, OEB staff submits that the proposed pole replacement program does not adequately account for structural refurbishment cost savings, and therefore overstates the magnitude of the capital program necessary to maintain constant overall system reliability.

OEB staff submits that potential cost savings through refurbishment practices could be balanced with an overall reduction in capital spending in order to hold overall reliability constant over the planning period. OEB staff notes that the refurbishment of 14% (or 10,000) of poles, rather than their replacement, amounts to overall capital savings of

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169 10,000 poles were identified as potential candidates for refurbishment. 10,000 candidates / 72,000 total replacements = 14%.

170 Oral Hearing, Volume 9, page 84, lines 19-27.

171 EB 2017-0049, Exhibit B1-1-1, Section 1.6, Attachment 1, page 16 of 33.

172 Oral Hearing, Volume 9, page 86, lines 21-25.

approximately $78 million[173] over the 2018 to 2022 period (or 2.2% of the five year overall capital budget of $3.6 billion), based on a pole replacement unit cost of $9,100.[174]

OEB staff submits that Hydro One's pole replacement planning should be modified to include structural refurbishment as a substitute for pole replacement where applicable, which would result in a reduction in the required capital expenditure for pole replacement.

(ii) Distribution Station Refurbishments

Background

Distribution station refurbishments comprise a significant proportion of the system renewal capital spending forecast in Hydro One's Plan-B modified, with a total budget of $148 million over the planning period.[175]

OEB Staff Submission

OEB staff submits that the evidence shows that Hydro One does not have defined scopes or confidence in the accuracy of cost estimates for distribution station refurbishment projects that are beyond the 12-18 month planning horizon.[176] Specifically, capital cost estimates for distribution station refurbishments are largely based on planner's estimates which are derived from historical station refurbishment unit costs[177] with accuracy ranges of +/- 50 %.[178] Additionally, station refurbishment projects do not always involve like-for-like replacements and different projects can have significant scope differences, which also affect cost estimation accuracy.

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[173] OEB Staff notes that it is unclear whether Hydro One treats pole refurbishments as an expense or capital investment. Hydro One confirmed at the oral hearing that refurbishment is an expense (Volume 9, page 87, lines 13-19), but Hydro One transmission capitalized the cost of steel structure re-coating which is a refurbishment methodology that extends the service life of structures (EB-2016-0160, Exhibit B1-03-11, Reference #: S76: Steel Structure Coating Program). For the purposes of this calculation, they are assumed to be capitalized. If they are indeed capitalized, then the capital savings of refurbishing 10,000 poles would amount to $91 million, corresponding to overall capital savings of approximately 2.5% ($91 million / $3,571.3 million = 2.5%).

[174] Based on average target pole replacement gross cost per unit between 2018-2022 (EB-2017-0049, Exhibit I, Tab 18, Schedule SEC-29). The calculation of the savings would be 10,000 poles times 6/7ths of $9,100 or $78 million.

[175] EB 2017-0049, Exhibit B1-1-1, DSP Section 3.7, page 2 of 11.

[176] Oral Hearing, Volume 9, pages 97-98.

[177] Oral Hearing, Volume 9, page 94, lines 13-17.

[178] Oral Hearing, Volume 9, page 94.

Hydro One has stated that it is attempting to enhance cost estimation accuracy for all new station refurbishment projects by requesting detailed cost estimates prior to releasing the projects for execution, rather than its prior practice of releasing each project based upon an assumed unit cost.[179] However, the OEB is still expected to approve program funding based on non-scoped and low confidence unit cost estimate projects.

Hydro One further stated that it needs to replace a certain number of distribution stations under Plan B-Modified in order to maintain overall system reliability, however, OEB staff notes that the evidence filed does not adequately support individual station refurbishment capital expenditures under this program.

OEB staff is concerned that despite repeated specific requests for detailed project information made in interrogatories[180] and at the technical conference[181], Hydro One has not been able to produce even a high level scope of each individual project. OEB staff considers this problematic in the context of a Custom IR application because the OEB is being asked to approve five years of defined capital expenditures without an adequate scope for each project.

OEB staff is of the view that despite the substantial volume of DSP evidence filed, there remain important gaps in the record related to the cost, scope and need of the individual station refurbishment projects, and the level of supporting project documentation provided, specifically those that are planned beyond the 12-18 month planning horizon. As such, OEB staff submits that Hydro One has not demonstrated adequate planning or justification of the proposed level of expenditure for each of the forecast years and therefore provides further justification for the proposed overall reduction to capital expenditures discussed below.

(iii) General Considerations

Background

Hydro One's proposed allocation of overall capital expenditures between the categories for the forecast period (2018 - 2022) remains similar to the bridge and historical (2013-

[179] EB-2017-0049, Exhibit I, Tab 25, Schedule Staff-126.
[180] EB-2017-0049, Exhibit I, Schedule EnergyProbe-51 part f)
[181] Technical Conference, March 2, 2018, pages 96-98.

2017) allocation ratios, but the table below shows that the forecast total capital expenditures are expected to compound at an average rate of almost 7% over the forecast period.

Forecast Annual Growth Percentage

Category	Annual Growth Percentage					5-Year Average Growth Percentage
	2018	2019	2020	2021	2022	
System Access	(15.0%)	1.9%	2.1%	3.1%	2.5%	(1.1%)
System Renewal	16%	28.2%	5.6%	7.7%	24.4%	16.4%
System Service	2.1%	14.2%	(8.4%)	(7.9%)	(11.8%)	(2.4%)
General Plant	41.0%	17.6%	(31.0%)	(10.8%)	2.1%	3.8%
Total Capital	**(0.8%)**	**17.2%**	**(5.0%)**	**1.6%**	**12.0%**	**6.9%**

OEB staff notes that the above table demonstrates that this growth rate is largely the result of significant growth in, system renewal expenditures, which comprise nearly half of Hydro One's planned capital investments over the forecast period and are expected to compound at an average rate of more than 16% which significantly exceeds the expected rate of inflation. In addition, the proposed system renewal spending in forecast year 2022 ($451.1 million) is more than double the actual spending recorded in the 2017 bridge year ($214.3 million).

OEB Staff Submission

OEB staff notes that while Hydro One has stated that this level of spending is required under Plan B-Modified to keep reliability and asset condition constant over the planning period,[182] OEB staff submits that there is inadequate evidence justifying the proposed growth in renewal spending

OEB staff is concerned that even though this level of spending will result in an expected increase in overall system reliability after accounting for Hydro One's new vegetation management strategy, the identified preference of customers for keeping costs low and maintaining reliability at *status quo*, indicates that this amount of spending may not be required.

[182] Transcript Vol. 7 p. 140

As OEB staff has noted previously, system renewal expenditures are primarily driven by a pole replacement program, a trouble call and storm damage response program, lines sustainment initiatives and a distribution station refurbishment program. However, OEB staff is concerned that there is insufficient justification in the application to justify the proposed capital spending increase.

In this context, OEB staff notes that Hydro One's historical system renewal annual growth percentages, as shown in the table below, indicate that historical system renewal spending has actually decreased at an average rate of 4.0%:

Historical Annual Growth Percentage – System Renewal

Category	Historical Annual Growth Percentage				4-Year Average Historical Growth Percentage
	2014	2015	2016	2017	
System Renewal	(1.1%)	17.4%	(6.5%)	(25.7%)	(4.0%)

Hydro One's SAIDI and SAIFI trends have been relatively stable over the historical period[183] (adjusted to exclude force majeure weather events), indicating that past capital investment levels were adequate to maintain reliability and system condition.

However, as has already been noted, Hydro One is proposing an average annual growth of more than 16% in system renewal spending over the forecast period, which is significantly higher than the recent historical system renewal capital spending.

Hydro One attempts to show that due to the age and condition of its existing asset fleet, reliability performance is expected to deteriorate materially during the forecast period unless system renewal expenditures are significantly increased over the planning period.[184]

However, OEB staff submits that the evidence filed to date does not justify this position, rather, it provides opportunities for a reduction in capital spending as OEB staff has discussed due to the new vegetation management program, the use of pole refurbishments rather than replacements and the lack of detailed scoping of station refurbishment projects.

[183] EB 2017-0049, Exhibit B1-1-1, DSP Section 1.4, pp. 21-22.
[184] Transcript Vol. 7, p. 140; Technical Conference, March 2, 2018, pp.93-94

OEB staff submits that its position is further supported by Hydro One's relatively stable historical SAIDI and SAIFI trends. As a result, OEB staff submits that the average historical system renewal expenditures should be used as the baseline for system renewal expenditure going forward, and that annual system renewal increases be limited to the expected rate of inflation to account for any variability. Assuming a 2% inflation per year, the revised system renewal forecast expenditures become:

Forecast System Renewal Expenditures & Annual Growth Rates

Investment Category	Average Historical Expenditures	5 - Year Forecast Expenditures					Total 2018-2022 Forecast Expenditures ($ M)
	2013-2017 ($ M)	2018 ($ M)	2019 ($ M)	2020 ($ M)	2021 ($ M)	2022 ($ M)	
Original System Renewal	267.9	248.6	318.7	336.7	362.5	451.1	1,718
Original Annual Growth %		**16%**	**28.2%**	**5.6%**	**7.7%**	**24.4%**	
Revised System Renewal	267.9	273.2	278.7	284.3	290.0	295.8	1,422
Revised Annual Growth %		**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	

OEB staff concludes that based on the above approach, the total forecast system renewal expenditures can be reduced from $1,718 million to $1,422 million, representing a 17% reduction in system renewal cost, or an 8% reduction in overall capital budget for the five-year planning period.

System Access Expenditures

Background

System access is Hydro One's second largest capital investment category, representing approximately 23% of the total planned expenditures. These expenditures are primarily driven by new customer connections, line relocations and service obligations.

General Plant Expenditures

Background

General plant expenditures comprise 18% of the 2018-2022 forecast capital expenditures, driven primarily by fleet and equipment investments, construction of a new Integrated System Operations Centre and general facility improvements.

In its submission, below, OEB staff will be commenting on one of a group of investments summarized in Investment Summary Document (ISD) No. GP-30: Customer Service Regulatory Related (Investment GP-30).[185] Hydro One describes Investment GP-30 as follows:

> This investment would implement the Demand to Interval change which is OEB required. This is a non-discretionary investment. It would also implement the Dynamic Pricing Pilot which is a pilot program offered by the government to encourage energy conversation [*sic*]. Finally, it will implement the new rate design for Commercial & Industrial customers. This new rate is not OEB required. Hydro One will seek OEB's approval, via current process for changing rates, for this new rate design which is intended to encourage energy conservation among Commercial & Industrial customers.

Hydro One forecasts the plan period total cost as $14 million, with total project costs (which include amounts spent prior to 2018) forecasted to be $19.6 million.[186]

In discussing the reasons for increased general plant spending in 2016 and projected increases through 2019, Hydro One cites various general plant projects, including GP-30, which it refers to as "IT investments to implement mandated billing changes".[187] This may be accurate for a portion of the total GP-30 investment, but the ISD for GP-30 describes the investment in three parts: Demand to Interval Migration; Dynamic Energy Pricing; and New Rate Design for Commercial and Industrial Customers. OEB staff is concerned about the second item, described in the ISD as follows:

> 2. Dynamic Energy Pricing - On July 18, 2016, the Ontario Energy Board (OEB) issued its Regulated Price Plan Roadmap: Guideline for Pilot Projects on RPP Pricing. Hydro One submitted an application to develop and implement price and non-price pilots, including the continuation of Hydro One's existing pilot which allows customers to have different variations of Time of Use rates. Dynamic Energy Pricing encourages customers to reduce electricity usage and shift usage away from peak hours. Some participants also receive enabling technologies such as Wi-Fi thermostats and in-home displays to assess the

[185] Exhibit B-1-1, DSP Section 3.8, ISD: GP-30
[186] *Ibid*., p.4
[187] Exhibit B-1-1, DSP Section 3.6, p.3 of 9

> associated incremental savings. On September 23, 2015 [*sic*], the OEB agreed that there is value in extending Hydro One's existing pilot until April 30, 2017. Capital funding is required to extend the pilot beyond April 2017.

OEB staff believes that Hydro One's reference to September 23, 2015 is a typographical error, and that Hydro One is referring to a September 23, 2016 Decision and Order[188] in which the OEB granted a deferral account for costs associated with extending an existing Smart Grid Fund pilot project (SGF Pilot), particularly to maintain customer recruitments and enable a smooth transition from the SGF Pilot to a new pilot project (RPP Pilot) that Hydro One proposed in the context of the OEB's Regulated Price Plan Roadmap.

The OEB approved Hydro One's RPP pilot on October 23, 2017. On June 22, 2018, Hydro One filed a letter with the OEB advising that it was withdrawing its RPP Pilot and would be winding down customer participation in the SGF Pilot.[189]

System Service Expenditures

Background
The remaining 11% of forecast expenditures represent system service investments to address load growth and improve feeder performance.

OEB Staff Submission
OEB staff notes that system access and system service, on average, will not exceed the expected rate of inflation, being below zero, and general plant expenditures, on average, are only slightly above the expected rate of inflation. This indicates that these investment categories have been adequately paced over the forecast period.

OEB staff takes no issue with these expenditures.

OEB staff notes that Hydro One has not allocated the forecasted $14 million GP-30 investment across the various elements of this project and, as a result, OEB staff does not know if a discrete portion of the $14 million is attributable to the "Dynamic Energy Pricing" initiative. However, OEB staff submits that it would not be appropriate for Hydro One to recover the revenue requirement related to that element of Investment GP-30 if

[188] EB-2016-0201
[189] *Ibid*

the scope of the investment no longer requires such breadth. While the evidence does not enable OEB staff to identify a specific value for this portion of the capital item, OEB staff has taken it into consideration in its recommendation that the OEB reduce Hydro One's proposed capital program.

Overall Recommendations

OEB staff submits that the OEB should set rates for Hydro One on the basis of a 11% per annum cut in Hydro One's proposed $3.6 billion 2018 to 2022 capital program or approximately $400 million in total. This would bring Hydro One's average capital program for 2018 to 2022 in line with the average historical spend in 2013-2017. OEB staff makes this submission on the basis of its concerns outlined above that it believes justify a 17% reduction in the level of system renewal costs, which translates into about an 8% reduction in the overall capital budget. The additional 3% recommended reduction is a result of a number of concerns that would justify a further cut, however are more difficult to quantify. These have been detailed above and are summarized below.

Beyond this, OEB staff notes that there is a significant element of approximation in assessing an appropriate reduction as there are factors such as the impact of the new vegetation management program which, given it is in its very early stages of implementation, are hard to quantify at the present time.

In Issue 23 OEB staff has expressed concern about Hydro One's customer engagement and that it did not establish a clear enough relationship between the reliability/cost tradeoff that customers were prepared to accept. In Issue 24 OEB staff noted that it was unclear that the actual investment planning process considers the appropriate planning criteria to adequately address the interlinkages between the condition of distribution assets, service quality and system reliability. OEB staff is also concerned that Hydro One's claimed level of productivity savings of $398 million may be overstated and believes that a cut in the approved revenue requirement for capital programs would provide Hydro One with an additional incentive to become more productive.

The discussion concerning redirection under Issue 29 leads OEB staff to observe that Hydro One has shown it is capable of deferring capital projects, which were stated as necessary in the previous cost of service application, without jeopardizing system reliability. As a result, capital expenditures could be reduced.

Finally, OEB staff has expressed concerned about the extent of the scoping and business case information provided by Hydro One on many projects as well as the lack of clarity in terms of how it prioritizes projects and determines which ones get the go ahead, particularly in the context of the concerns expressed by the AG.

OEB staff believes that an 11% reduction would provide Hydro One with an additional incentive to provide better information as part of its next application.

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

Background

Hydro One provided the summary below of its common corporate costs for the application period:[190]

Total Corporate Common Costs 2016 to 2022

Corporate Common Cost $M	2016F	2017	2018	2019	2020	2021	2022	CAGR
Audit	$ 4	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	9.6%
Corporate Management	$ 20	$ 23	$ 23	$ 24	$ 24	$ 24	$ 24	3.6%
Customer and Corporate Relations	$ 45	$ 52	$ 52	$ 52	$ 52	$ 52	$ 52	2.5%
Facilities Real Estate	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10	$ 10	1.6%
Finance Total	$ 29	$ 33	$ 33	$ 33	$ 31	$ 31	$ 32	1.8%
Finance Inergi	$ 12	$ 11	$ 12	$ 12	$ 13	$ 13	$ 13	1.7%
General Counsel and Secretary	$ 9	$ 10	$ 10	$ 10	$ 10	$ 11	$ 11	2.6%
Information Solutions Division	$ 22	$ 21	$ 21	$ 21	$ 21	$ 22	$ 22	0.2%
Network Operating	$ 49	$ 49	$ 49	$ 50	$ 50	$ 51	$ 51	0.9%
Operations COO Office	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	3.4%
People & Culture	$ 14	$ 16	$ 16	$ 16	$ 17	$ 17	$ 17	3.5%
Planning	$ 49	$ 52	$ 52	$ 52	$ 52	$ 52	$ 53	1.3%
Regulatory Affairs	$ 23	$ 23	$ 23	$ 19	$ 19	$ 19	$ 21	-1.4%
Strategic Services	$ 1	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	10.4%
Total	**$ 288**	**$ 313**	**$ 312**	**$ 310**	**$ 312**	**$ 315**	**$ 320**	**1.8%**

	OM&A	Capital
Transmission Portion	19.0%	30.0%
Distribution Portion	26.4%	19.4%
Other Allocated	5.2%	

Hydro One stated that it utilizes a centralized shared services model to deliver its common services to its transmission and distribution businesses and to its affiliated companies. Each business and affiliate pays their share of these costs based on a cost allocation methodology developed by Black & Veatch (B&V, formerly RJ Rudden

[190] Exh. A-3-1, Attach. 2 Filed: 2017-03-31.

Associates) and approved by the OEB which utilizes a breakdown of activities and drivers based on cost causality principles. Hydro One stated that the B&V study filed in this application is the same study as was approved by the OEB in the most recent transmission rates proceeding[191] and therefore remains appropriate.[192]

Hydro One noted that of the total common costs, 3.5% or $11 million per year is not allocated to a regulated business as it relates to management of non-regulated activities (for example mergers and acquisitions and non-regulated strategy work). Hydro One stated that over the planning period between 2016 and 2022, corporate common expenditures are expected to rise by approximately 11% with a compounded annual growth rate of less than 2%, but still in excess of the expected price cap factor of 1.3%. Hydro One further stated that planned productivity savings and cost efficiencies play an integral role in capping the costs and, in some cases, fully offsetting required increases. From 2018 onwards the costs stabilize and annual increases are mostly due to inflationary pressures.

OEB Staff Submission

OEB staff accepts Hydro One's proposed approach to common corporate cost allocation as reasonable as there have been no factors that have arisen since the most recent transmission case that would justify a reconsideration of Hydro One's approach to allocating these costs.

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

Background

The overhead capitalization rates proposed by Hydro One in this application are as shown in the table below:[193]

[191] EB-2016-0160.
[192] Argument-in-chief, p. 116.
[193] Exh. D1, Tab 3, Sch. 1, p. 2, Table 1 Filed: 2017-03-31.

Overhead Cost Category	Test Years (%)					Test Years ($ millions)				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
Capitalized Administrative & General Costs	10%	9%	9%	9%	9%	70.7	74.4	73.5	74.2	78.4
Capitalized Planning, Customer and Operating Costs	2%	2%	2%	2%	2%	12.3	12.4	12.5	12.7	12.7
Total	12%	11%	11%	11%	11%	83.0	86.8	86.1	86.9	91.1

[1] Administrative & General Costs include all common corporate functions and services costs
[2] Operating costs include asset management, operating and customer care management costs

Hydro One stated that its overhead capitalization policy is consistent with USGAAP and that it capitalizes costs that are directly attributable to capital projects and also capitalizes overhead costs supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

Hydro One noted that in its decision on Hydro One's 2010 and 2011 distribution rates,[194] the OEB had accepted the methodology, recommendations and the allocation of costs from a study by B&V. This study had derived an overhead capitalization rate for Hydro One distribution's common corporate costs. Hydro One also noted that this accepted methodology was also used in its two most recent transmission rate applications.[195]

Hydro One proposed that the overhead capitalization rate, as calculated in the B&V study in 2016, continued to be a reasonable method of distributing common corporate costs to capital projects. Hydro One stated that its submissions in the application reflect this overhead capitalization rate.

Hydro One noted that the capitalization rates are down slightly relative to the previous distribution study mainly due to higher planned capital expenditures.

Hydro One noted that in the most recent transmission decision, the OEB had indicated that it would consider whether it should initiate a policy review regarding USGAAP and capitalization of overhead amounts. Hydro One further noted that policy changes, if any, resulting from such a future generic review would be implemented in a future rate

[194] EB-2009-0096, April 9, 2010.
[195] EB-2014-0140 and EB-2016-0160

application. Overall, Hydro One submitted that the methodologies used to determine the distribution overhead capitalization rate for 2018 and onward are appropriate.[196]

OEB Staff Submission

OEB staff addresses the on-going use by Hydro One of US GAAP as the basis for capitalizing its overhead costs for regulatory purposes as part of the OEB staff submission on issue 58.

E: RATE BASE & COST OF CAPITAL

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

Background

Hydro One provided the table below summarizing its distribution rate base for the 2018 to 2022 period:[197]

$millions

Description	Test				
	2018	**2019**	**2020**	**2021**	**2022**
Mid-Year Gross Plant	11,834.3	12,413.5	13,072.2	13,917.1	14,595.9
Mid-Year Accumulated Depreciation	(4,468.7)	(4,703.5)	(4,972.4)	(5,317.5)	(5,646.5)
Mid-Year Net Plant	**7,365.6**	**7,710.0**	**8,099.8**	**8,599.6**	**8,949.4**
Cash Working Capital	321.2	335.7	348.3	378.5	395.3
Materials and Supply Inventory	4.1	5.5	6.5	5.9	5.5
Distribution Rate Base	**7,690.9**	**8,051.2**	**8,454.5**	**8,984.0**	**9,350.2**

Hydro One stated that in accordance with the 2006 Electricity Distribution Rate Handbook, the rate base underlying each of the test years' revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Hydro One further stated that net fixed assets are calculated as gross plant in service minus accumulated depreciation and contributed capital.

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[196] Argument-in-chief, p. 116.

[197] Exh. I, Tab 33, Sch SEC-67, p. 2, Table 2 Updated: 2018-05-04

Hydro One noted that the total rate base in 2017 was expected to be $158.3 million (revised to $170.7 million in the 2018 update reflecting the 2017 actual) above the OEB approved amount.[198] Hydro One stated that the resulting variance of 2.2% (increased to 2.4% in the 2018 update) was 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 was stated as contributing to the higher rate base, partially offset by lower demand for distribution generation connections and reduced spending on wood pole replacements.

Hydro One submitted that the amounts it is proposing for rate base are appropriate, as evidenced by: (1) the robust process it has undergone in order to forecast and plan for its capital needs including productivity already embedded in the proposed capital expenditures and (2) appropriate depreciation expense amounts and working capital component of the rate base. Finally, Hydro One stated that it was holding itself accountable to its customers with regard to its capital forecast through its proposed CISVA.[199]

OEB Staff Submission

OEB staff submits that Hydro One's proposed distribution rate base for the 2018 to 2022 period is reasonable subject to any revisions OEB staff may propose in other sections of this submission (most particularly with respect to appropriate levels of capital expenditures).

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

Background

Hydro One stated that its net cash working capital requirement for its distribution operations for the 2018 test year is $321.2 million or 7.7% of the sum of OM&A and cost of power expenses and, applying the same formula, is also 7.7% of the sum of OM&A and cost of power expenses for each year in the 2019 to 2022 period.

Hydro One stated that in preparing new rate applications, it had commissioned Navigant to conduct updated lead-lag studies for both the transmission and distribution businesses

[198] Exh. D1 Tab 1 Sch. 1, p. 2 Updated: 2017-06-07
[199] Argument-in-chief, p. 117.

in March 2015 and that both studies had been based on 2014 actual results. Hydro One further stated that the methodology used to determine the net cash working capital required is based on the Navigant study that was accepted by the OEB and updated as part of the current filing.

Hydro One added that it had also calculated the net cash working capital requirement of each of the Acquired Utilities using the 7.7% determined by Navigant.

Hydro One noted that during the oral phase of the proceeding, it had confirmed that it was lowering its proposed revenue requirement to reflect the impact of the Fair Hydro Plan on cash working capital.[200]

OEB Staff Submission

OEB staff notes that the OEB's policy is that applicants may take one of two approaches for the calculation of the allowance for working capital, which are: (1) use a default allowance approach (7.5% of the sum of the cost of power and operating, maintenance and administration costs), or (2) file a lead/lag study.[201]

OEB staff submits that the 7.7% rate is reasonable and that Hydro One's allowance for working capital has been calculated in accordance with OEB policy and should be accepted by the OEB, subject to any adjustments to the components of the calculation proposed by OEB staff in other sections of this submission which would impact this calculation.

35. **Is the proposed capital structure appropriate?**

Background

Hydro One stated that its deemed capital structure proposed for distribution rate-making purposes in the application is 60% debt, consisting of 4% deemed short-term debt and 56% long-term debt and 40% common equity.

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[200] Argument-in-chief, p. 117.

[201] OEB "Allowance for Working Capital for Electricity Distribution Rate Applications," June 3, 2015

OEB Staff Submission

OEB staff submits that Hydro One's proposed capital structure is in accordance with OEB policy and should be accepted by the OEB.

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?**

Background

Hydro One stated that it would update the short-term debt rate for the 2018 to 2020 test years based on the 2018 deemed short-term debt rate based on the September 2017 Bank of Canada data, and the average spread calculated by the OEB to be released in the fall of 2017. For 2021 and 2022, Hydro One would update the short-term debt rate for these years based on the 2021 short-term debt rate to be calculated and released by the OEB in the fall of 2020.

Hydro One stated that it would update the equity cost of capital for the 2018 to 2020 test years using the 2018 ROE based on the September 2017 Consensus Forecasts and Bank of Canada data which would be available in October 2017. For 2021 and 2022, Hydro One would update the equity cost of capital based on the 2021 ROE to be calculated and released by the OEB in the fall of 2020.

Hydro One submitted that its proposed approach was appropriate as it is consistent with its prior applications approved by the OEB and ensures that the revenue requirement is based on the most recent information available, while also being consistent with the intent of the annual update to the cost of capital parameters issued by the OEB.[202]

OEB Staff Submission

OEB staff considers Hydro One's approach to this matter as reasonable, except for the proposal to update these costs in 2020 for 2021 rates, which is discussed in more detail under Issue 14.

[202] Argument-in-chief, p. 118

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

Background

Hydro One stated that its distribution operations are allocated a portion of the debt issued by Hydro One Networks Inc. to Hydro One Inc. Hydro One Networks Inc. issues debt to Hydro One Inc. to reflect debt issued by Hydro One Inc. to third party debt investors.

Hydro One stated that the amount of each Hydro One Networks Inc. debt issue that is allocated to distribution is based on its most recent forecast of borrowing requirements, which are driven mainly by debt retirement, capital expenditures net of internally generated funds and the maintenance of its capital structure.

Hydro One noted that the OEB had determined that for the embedded debt the rate approved in prior OEB decisions was to be maintained for the life of each active instrument, unless a new rate was negotiated, in which case it would be treated as new debt. Hydro One stated that the cost rates on its existing embedded long-term debt had been approved by the OEB in previous proceedings. For new debt the rate used is the prudently negotiated contract rate negotiated by Hydro One Inc.

Hydro One stated that it had assumed for rates effective January 1, 2018, the forecast interest rate for Hydro One distribution debt issues would be based on the September 2017 Consensus Forecasts and the average of indicative new issue spreads for September 2017 that will be obtained from the company's medium term note dealer group for each planned issuance term. In addition, Hydro One assumed that the long-term debt rate would be updated to reflect the actual issuances of debt since the time of the original application, consistent with the OEB's previous distribution rate Decision[203] and changes in the interest rate forecast.

Hydro One submitted that its long term debt forecast is appropriate as it reflects the needs of the capital programs of the distribution business and it is non-discretionary as it is derived from what Hydro One expects to spend on capital.[204]

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[203] EB-2013-0416

[204] Argument-in-chief, p. 118

OEB Staff Submission

OEB staff considers Hydro One's approach to this matter as reasonable with the exception of Hydro One's assumption stated above that the long-term debt rate would be updated to reflect the actual issuances of debt since the time of the original application, consistent with the OEB's previous distribution rate Decision and changes in the interest rate forecast. OEB staff is unclear as to which reference in the previous distribution Decision would support Hydro One's position and therefore submits that the requested update should not be permitted.

F: OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

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?**

Background

Hydro One stated that its proposed test year OM&A expenses resulted from the business planning and work prioritization processes described in its DSP. Hydro One further stated that this process reflected a risk-based decision-making approach to ensure appropriate and cost-effective investments that demonstrated its commitment to aligning customer needs and preferences, responsible stewardship of the company's distribution assets and rate impacts.

The table below provides a summary of Hydro One distribution's OM&A expenditures for the historical, bridge and test years:[205]

[205] Exh I Tab 38 Sch. SEC-70, p. 2 Updated: 2018-06-11.

$millions

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	304.7	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	8.8	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	31.9	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	123.4	111.6	128.7*
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	84.9	54.7	48.7 **
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	5.0	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**558.7**	**593.0**	**576.7**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*-0.7%*	*0.7%*	*3.2%*
% Change (Test vs. 2016 Actual)						*-0.7%*		*2.5%*

* Reflects reduction of bad debt based on the Fair Hydro Plan.
** Reflects reduction of transformation costs and OPEB OM&A as described in Exhibit Q.

Hydro One stated that over the course of the plan, its OM&A spending would increase annually by the Inflation Factor reduced by the Productivity Factor.

Hydro One submitted that since 2014 when OM&A expenses were high due to customer care expenses related to the implementation of a new customer information system, OM&A expenses had been kept in line and were in fact shrinking.[206]

Sustainment

Hydro One stated that sustaining OM&A represents expenditures required to maintain existing components of the distribution system to ensure they continue to function as designed. Hydro One added that it manages its sustaining OM&A by dividing the expenditures into the following four investment categories: (a) stations; (b) lines; (c) meters, telecom, and control; and (d) vegetation management. Hydro One provided the following summary of sustaining OM&A.[207]

[206] Argument-in-chief, p.. 119-120.
[207] Exh. I Tab 38, Sch. AMPCO-37, p. 1 Updated: 2018-05-04

$millions

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Stations	25.7	25.3	27.6	23.8	28.4	23.9	28.9	24.8
Lines	145.2	144.7	141.3	141.4	149.7	135.5	152.4	153.8
Meters, Telecom and Control	14.2	16.6	18.5	16.2	18.7	18.4	18.5	18.6
Vegetation Management	140.6	118.0	129.0	142.3	164.6	126.9	167.3	149.6
Total	**325.7**	**304.6**	**316.5**	**323.7**	**361.4**	**304.7**	**367.1**	**346.7**

Hydro One noted that the proposed sustaining OM&A spending for the 2018 test year is trending upward relative to the historic actual and forecast expenditures, but the 2018 proposed level of spending remains below the previous OEB-approved levels.

In the application as filed,[208] Hydro One noted that the 2018 test year spend reflected an approximately 3.5% annual increase relative to the forecast expenditures over the 2016 and 2017 period. This increase over the two-year period was largely attributed to:

- An increase of approximately $7 million in the vegetation management program to address the backlog in vegetation maintenance, increase responsiveness to site specific customer concerns, and more effectively mitigate emergent safety and reliability concerns

- An increase of approximately $12 million in the lines demand work program to address trouble calls and customer requests for underground cable locates

OEB staff notes that the above assessment was done by Hydro One on the basis of a 2017 bridge year forecast of $334.5 million, which turned out to be significantly higher (roughly 10%) than the actual level of $304.7 million shown in the above table.

Hydro One stated that the 2016 actual expenditure was in line with historic actual expenditures. The exception was in 2015 when the actual expenditure was strategically reduced below the approved amount to redirect funding to address increased costs associated with the implementation of Hydro One's customer information system (CIS).

[208] Updated: 2017-06-07

Hydro One also stated that both the 2016 actual and 2017 forecast expenditures are below the OEB-approved amounts primarily due to improvements in the vegetation management program. The forecast for the 2018 test year remains below the 2016 and 2017 OEB-approved amounts due to productivity improvements.

(i) Sustainment Programs (except Vegetation Management)

Hydro One stated that the stations program addressed demand and planned corrective maintenance of its distribution stations as well as land assessment and remediation (described as testing and carrying out remedial work to manage contaminated soil at stations). Hydro One further stated that demand maintenance is necessary to respond to component failures, while planned work prevents such failures. Hydro One noted that spending on these programs is in line with historical amounts.

Hydro One stated that the forecasted expenditure in the lines category covers four programs, which are: (1) demand work (trouble calls, locates, connects and disconnects); (2) scheduled maintenance; (3) government mandated PCB equipment and waste management; and (4) other services (transmission lines, track service quality indicators, fund specific community events, and complete joint use audits, etc.)

Hydro One further stated that the overall proposed spending increase on lines from the 2017 approved amount is $1.4 million (or less than 1%) which was due to anticipated increases in customer requests for underground cable locates and inflation.

Hydro One stated that the forecasted expenditures for meters covers three programs, which are: (1) retail revenue meters (routine and corrective maintenance); (2) wholesale revenue meters (routine and corrective maintenance and Independent Electricity System Operator (IESO) registration/inspection); and (3) telecom, monitoring and control (collection of energy consumption data, and control of sectionalizing switches and electronic reclosers). Hydro One explained that each of these programs is a demand program required to maintain Hydro One’s billing meters to ensure accurate billing.

Hydro One noted that no intervenor had cross-examined the Asset Management Panel on the appropriateness of the level of spending on any of these programs.[209]

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[209] Argument-in-chief, pp. 120-121.

(ii) Vegetation Management

Hydro One stated that the vegetation management program is the sustaining OM&A program that received by far the most attention during the evidentiary portion of the proceeding. Hydro One noted that during the proceeding it had introduced a new vegetation management program, called the Optimal Cycle Protocol (OCP), which would allow it to run a three year cycle on all of its lines by focusing only on defects and trees that have the potential to become defects in the next three years. Hydro One stated that the main benefit of this change in approach is that vegetation on all of its distribution system rights-of-way will be examined within a much shorter cycle time, which is every three years as compared to the current cycle average time of over nine years. Hydro One further stated that targeting only high risk vegetation allows for greater coverage and focuses on achieving significant reliability improvements across the system and for the same expenditure level as originally proposed for Hydro One's previously implemented program.

Hydro One projected that based on this new OCP vegetation management program, by 2022, it will have achieved a 40% reduction in vegetation caused SAIDI hours, Force Majeure Excluded over its 10 year average, and a 58% reduction based on its 2017 year-end caused SAIDI. Furthermore, it will be able to achieve these significant reliability improvements with the same projected vegetation management spending as was in the original application, which was approximately $150 million in 2018. Hydro One summarized this as meaning that for the same costs, but using a different method, it will be able to produce better results.

Hydro One observed that during the oral phase of the proceeding, both SEC and OEB staff had suggested to the Asset Management Panel that because of the reliability improvements provided by the vegetation management program, it should be able to cut spending to maintain what Hydro One characterized as its alleged target of maintaining reliability. Hydro One submitted that this line of cross-examination was predicated on a fundamental misreading of the application. Hydro One cited the testimony of Ms. Bradley to explain what this fundamental misreading was:[210]

> MS. BRADLEY: But, Mr. Rubenstein, the plan that we've put forward, the capital plan is geared to not enabling our capital base or our assets to deteriorate. The vegetation management program is not renewing our pole population, it is not renewing our

[210] Transcript, Vol. 7, p.140 L4 to L12

> stations population. The capital investments that are currently in the plan are required to maintain and prevent further deterioration of those assets.
>
> The vegetation management program, unfortunately, isn't going to renew those assets.

Hydro One argued that it would also be illogical to reduce vegetation management expenditures such that the program is then designed to achieve the same level of system reliability as the initial program, as such an approach would mean from an operational perspective that less vegetation management would be carried out on the system. Hydro One stated that arbitrarily adopting modifications to the expert recommendations by reducing OCP proposed level expenditures would allow high risk vegetation to go unmanaged and result in potentially greater and not lesser system outage impacts.

Hydro One submitted that such outcomes are not supported by any evidence filed in this proceeding and should be avoided. Hydro One submitted instead that full funding for the OCP program should be approved as its adoption will improve system reliability, which in the long term facilitates lower costs and improved service for customers.[211]

Development

Hydro One stated that development OM&A expenditures are required to perform technical studies and develop construction standards for the connection of load and generation customers to the distribution system. These expenditures also support research into new technologies and the development of power quality solutions and ensure that the existing and forecast customer load and generation demands are met, system reliability is maintained, regulatory requirements are satisfied, and the impact of distributed generation connected to the system is effectively monitored.

Hydro One further stated that development OM&A investments are categorized as follows: (a) engineering and technical studies; (b) distributed generation connections; (c) distribution standards programs; (d) research development and demonstration; and (e) customer power quality programs. Hydro One provided the following summary of development OM&A.[212]

[211] Argument-in-chief, pp. 121-127
[212] Exh. I Tab 38, Sch. SEC-70, pp. 2-3 Updated: 2018-05-04

$millions

Description	**Historic**					**Bridge**		**Test**
	2014	**2015**		**2016**		**2017**		**2018**
	Actual	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Forecast**
Engineering and Technical Studies	4.0	3.8	4.7	4.2	4.7	3.5	4.7	1.7
Distributed Generation Connections	2.6	2.5	2.2	2.5	2.0	2.6	2.0	2.9
Distribution Standards Program	3.9	3.4	5.6	3.3	5.8	0.9	6.0	4.5
Research Development and Demonstration*	0.4	1.2	2.9	1.8	5.2	1.7	4.3	1.6
Customer Power Quality Program	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.2
Total	**11.0**	**10.9**	**15.4**	**11.9**	**17.8**	**8.8**	**17.0**	**11.0**

** In 2016, investments in smart grid related studies were integrated under the new Research Development and Demonstration ("RD&D") program; as such costs associated with these studies prior to 2016 have been included under RD&D in the above table.*

In the updated application as filed[213], Hydro One noted that the proposed development OM&A spending for the 2018 test year is a decrease of $2.2 million relative to the 2017 bridge year forecast, largely due to a decline in the engineering and technical service program caused by the planned modernization of the distribution system.

Hydro One further noted that the 2017 bridge year expenditures forecast is $1.3 million higher than the 2016 actual expenditures, largely due to the increased focus on technology projects in the Distributions Standards Program, and the forecast increase in requests for the connection of distributed generation projects to Hydro One's distribution system and the ongoing cost of monitoring these distributed generators for power quality.

OEB staff notes that the above statements do not match with the above table as it incorporates the 2017 actual amount of spending of $8.8 million as compared to the forecast at the time of $13.2 million, which is roughly 50% over the actual level.

Hydro One stated that the 2016 historic year actual expenditure represented an increase of about $1.0 million relative to the actual expenditures in 2014 and 2015 due to increases in two of the Development OM&A programs. However, Hydro One also noted that spending over this period is below the OEB-approved levels by an average of $4.7

[213] Exh. C1, Tab 1, Sch 3, p. 2 Updated: 2017-06-07

million per year due to a reallocation of ESA fees to the Sustaining OM&A budget; changes in standards development; a wider selection of vendors which enabled pricing and service quality improvements; and a redirection in research focus.

Operations

Hydro One stated that Operations OM&A investment funds the operating function which coordinates and dispatches crews as required, plans for and reacts to system contingencies, schedules and coordinates planned outages, provides customer notifications, and monitors and reports on the performance of the distribution system. Operators at the Ontario Grid Control Centre monitor the distribution system. Operations OM&A spending also supports Hydro One's environment, health and safety activities and the Smart Grid. Hydro One provided the following summary of operations OM&A:[214]

$millions

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Operations	17.7	18.1	16.9	19.6	17.1	21.2	17.1	18.5
Operations Support	4.6	4.4	5.4	4.8	5.4	3.4	5.5	4.9
Environment, Health and Safety	1.4	1.5	2.7	1.6	2.8	1.8	2.6	1.8
Smart Grid*	5.9	3.5	11.0	5.6	14.1	5.5	12.4	11.5
Total*	**29.5**	**27.6**	**35.8**	**31.5**	**39.4**	**31.9**	**37.5**	**36.7**

Hydro One noted that operations expenditures were higher in both 2015 and 2016 than the OEB-approved levels and explained that the increases over this period were due to the inclusion of a shift premium for control room staff, collective agreement obligations, the transfer of three employees from Power System IT to Network Operating and an increase associated with additional governance and oversight expenditures.

With respect to Operations Support expenditures, Hydro One noted that these expenditures were below OEB-approved amounts in 2015 and 2016 and, as it considered these reductions sustainable has planned for expenditures during the test years below the historic OEB-approved levels.

[214] Exh. I Tab 38, Sch. SEC-70, p. 3 Updated: 2018-05-04

Hydro One stated that this trend was due to program re-assessments and subsequent reductions to program expenditures, directly related to the use of data based on historical trends, the current advantages and efficiency of the geographical information system and distribution operating maps and diagrams.

Hydro One stated that increases in the Environment, Health and Safety category from historic to bridge and test years were due to ongoing audit requirements to maintain OHSAS 18001 (Occupational Health & Safety Management System) certification, conducting the Safety System Evaluation every two years, Hazard Hamlet public safety program (visits to schools, fall fairs and community events), increased requirements for eLearning packages, and updates to the Protection and Control Training Laboratory.

OEB staff notes that the actual amounts spent in this category were significantly below the OEB-approved amounts for the 2015 to 2017 period, though the 2018 forecast amount of $1.8 million is in line with actual spending.

Hydro One stated that smart grid expenditures for 2015 to 2017 were trending below the OEB-approved values as the rollout of the Distribution Management System upgrade was delayed in favour of the next version of the application. Hydro One stated that this project is expected to be completed in 2018.

Customer Care

Hydro One stated that its Customer Care OM&A funds are used to provide services to residential, small business, commercial, and industrial customers. The key functions of Customer Care are: (a) responding to customer inquiries when they contact the call center; (b) obtaining meter readings; (c) issuing timely and accurate bills; (d) processing customer payments; (e) collections program management, and (f) providing financial assistance to low-income customers through the OEB’s Low-Income Energy Assistance Program (LEAP). Hydro One provided the following summary of customer care OM&A allocated to distribution operations.[215]

[215] Exh. I Tab 38, Sch. SEC-70, p. 4 Updated: 2018-06-11

$millions

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Call Center Operations (1)	79.5	56.4	38.5	41.5	38.8	44.0	39.9	44.5
Meter Reading	23.5	18.7	14.9	17.8	14.3	18.8	14.0	19.2
Third Party Support (2)	13.6	13.2	12.2	14.1	12.5	14.1	12.9	14.6
Field Support	4.9	12.0	7.1	14.0	7.3	7.2	7.5	8.1
Regulatory Compliance (LEAP)	2.2	4.2	2.1	4.1	2.2	3.7	2.3	4.3
Net Bad Debt	66.8	29.5	15.5	6.8	15.4	16.1	14.4	18.2 (5)
Customer Care Staffing (3)	18.9	21.5	21.3	20.5	20.4	19.4	20.6	19.8
Total Customer Care OM&A (4)	**209.3**	**155.4**	**111.6**	**118.8**	**110.9**	**123.4**	**111.6**	**128.7**

(1) Previously referred to as "Customer Service Operations", "Customer Operations" and "Settlements".
(2) Previously referred to as "Service Support" and "Service Enhancements".
(3) Previously referred to "Customer Service Management", "Customer Business Relations", "Customer Care Management", "Customer Experience", and "Conservation and Demand Management".
(4) Costs associated with the Smart Grid Pilot are now included in the Exhibit C1, Tab 1, Schedule 4 (Operations OM&A) Exhibit.
(5) Net Bad Debt in 2018 have been reduced by $2.9 million as per Exhibit I-33-Staff-179.

(i) *Call Center Operations*

Hydro One stated that its Call Centre Operations reflected its costs under its outsourcing agreement with Inergi LP to deliver customer-facing services, including: call center services, billing, collections, settlements, and distributed generation services to Hydro One customers. Hydro One stated that in 2016, the call center handled over 2.7 million calls from customers and responded to over 63,000 emails.

Hydro One explained that in 2014 and 2015, actual expenditures were higher than OEB-approved levels due to the increased costs associated with the implementation of Hydro One's CIS in May 2013 and the following support period.

Hydro One also initiated a competitive Request for Proposal in 2014 in preparation for the expiration of the outsourcing agreement. This caused actual expenditures to be higher than OEB-approved levels in 2015 due to the market price of the new outsourcing contract, higher than expected transition costs associated with the new outsourcing contract, and the elimination of a sub-contractor. In 2016, spending levels were 7% higher than OEB-approved levels as a result of improved customer service targets within the call center, new service level guarantees, and extended hours of operation for certain parts of the call center. As a result, expenditures were also projected to be higher than OEB-approved levels in 2017 and beyond, with annual expenditures also expected to increase year-over-year due to an inflation provision in the contract.[216]

At the Presentation Day, Hydro One stated that it was in the process of in-sourcing customer care, including bringing the call center back into Hydro One.[217] This in-sourcing was stated as not included in the application.[218]

> MS. GIRVAN: Okay, thank you for that. And just a quick clarification question. You said that you're in-sourcing certain aspects of customer care. Is that included in the application?
>
> MR. PUGLIESE: No, because the cost is going to be flat to down, in terms of -- so it's factored in. The cost of operating the call centres today and our outsource agreement is included, yes, in the application, and as we look through the course of the coming years, what we anticipate is the cost, operating costs, will be flat, and we will continue to look at operating improvements in there to bring those cost savings down.

Hydro One stated that the cost of the call centre is largely driven by the cost of Power Workers' Union (PWU) labour. Hydro One noted that when bringing the call centre in-house, it had assumed the contracts of PWU workers who are employed in the call centre. Hydro One explained that given the labour intensive nature of the work, it does not forecast any cost savings due to the in-sourcing of the call centre, but believes it will be able to offer a higher quality of customer service and have more flexibility in how it

[216] Exh. C1, Tab 1, Sch. 5, p. 3 Updated: 2017-06-07
[217] Transcript, Presentation Day, p. 95, L24-L26
[218] Ibid, p. 100 L2-L13.

operates its call centre. Hydro One also noted that there are no transition costs included in the 2018 test year expense.[219]

(ii) *Meter Reading*

Hydro One stated that meter reading costs were higher than OEB-approved levels in 2014 and 2015 due to the implementation of the CIS and the following support period. Forecasted expenditures in 2016 and 2017 are also higher than OEB-approved levels as a result of improved bill accuracy targets, whereby 98% of bills were to be issued on actual meter reading. Spending in 2017 and 2018 was forecast to be higher than OEB-approved levels as a result of amendments to the Distribution System Code (DSC) requiring distributors to install an interval meter on any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW. However, Hydro One stated that expenditures would decline in 2018 versus 2017 as a result of system enhancements in the field and improvements to the smart meter network infrastructure.[220]

(iii) *Third Party Support*

Hydro One stated that third party support costs were higher than OEB-approved levels in 2015 and 2016 due to unexpected increases in postage rates and lower than expected uptake in ePost. In order to mitigate increasing postage costs in 2017 and over the Custom IR term, Hydro One launched a new e-billing solution at the end of 2016. Hydro One also stated that the 2018 forecast test year expenditure is 17% higher than OEB-approved levels in 2016 as a result of increasing postage rates and an amendment to the DSC requiring that distributors issue bills to non-seasonal residential customers and general service under 50 kW customers on a monthly basis.[221]

(iv) *Field Support*

Hydro One stated that field support spending levels in 2015 and 2016 were higher than OEB-approved levels as Hydro One had gradually resumed on-site field visits and disconnections. In addition, Hydro One examined all customer-facing policies and practices and introduced new customer friendly policies. Hydro One further stated that in addition, as an extension to its annual pause on disconnections, it had launched a Winter

[219] Argument-in-chief, p. 130
[220] Exh. C1, Tab 1, Sch. 5, pp. 4-5 Updated: 2017-06-07
[221] Exh. C1, Tab 1, Sch. 5, pp. 5-6 Updated: 2017-06-07

23 Relief Program in 2016, which was designed to help customers experiencing extreme hardship get their electricity service reconnected for the winter. The 2018 test year expenditure is 42% lower than 2016 expenditure, as Hydro One stated that it is expected field collection volumes will return to normal. Furthermore, the introduction of remote disconnect technology in mid-2016 is expected to result in a reduction in field collection expenditures in 2017 and beyond.[222]

(v) *Regulatory Compliance (LEAP)*

Hydro One stated that in recent years, the number of low-income customers has increased as customers are struggling with increasing energy bills. As such, demand for this program from Hydro One customers exceeds the OEB's mandate. Hydro One noted that in 2015 and 2016, its contribution to LEAP was approximately $2 million more than the OEB's 0.12% revenue requirement and forecast that in 2017 and beyond, demand for LEAP funding would continue to increase, which is why the test year expenditure is approximately twice as high as the OEB approved level. Hydro One stated that it plans to contribute additional funding in 2017 and beyond.

(vi) *Net Bad Debt*

Hydro One stated that in 2014 and 2015, net bad debt expenses were higher than OEB-approved levels due to the suspension of its collections program from May 2013 to early 2016 related to the implementation of CIS. In December 2013, shortly after the implementation of the CIS, the provision rates were also revised to reflect the increased risk of uncollectible accounts receivables following Hydro One's decision to suspend all collections activity.

Hydro One further stated that because its collections risk profile had improved since the reactivation of collections in 2016, it had modified its provision rates in 2016 to more accurately reflect its bad debt exposure. This resulted in a one-time adjustment that was approved by Hydro One's external auditors and had resulted in a $12.6 million reduction in 2016. However, increasing revenues over the term of the Custom IR were expected to result in increased expenditures from 2017 to 2022. Hydro One stated that despite these increasing revenues, it is committed to reducing net bad debt as a percentage of revenue from 2017 to 2022. In 2017 and 2018, net bad debt was expected to return closer to

[222] Exh. C1, Tab 1, Sch. 5, pp. 6-7 Updated: 2017-06-07

historical norms (meaning before Hydro One's recent CIS implementation), adjusted for increased revenue. As a result, 2018 test year expenditure will be higher than OEB-approved levels in 2016.

(vii) Customer Care Staffing

Hydro One stated that customer care staffing expenditure increased from 2014 to 2015 as it focused on a renewed level of service for customers, while bridge and test year expenditure are forecast as lower than 2016 OEB-approved levels due to efficiencies achieved from headcount reductions through attrition. Hydro One also stated that costs are expected to remain relatively constant over the planning period.

OEB staff notes that for the customer care category of OM&A, unlike the sustainment, development and operations categories where the actual levels were well below the forecast levels, for this category, the actual levels were well above the forecasts; 39% in 2015, 7% in 2016 and 11% in 2017.

Common Corporate Costs and Other

Hydro One stated that the Common Corporate and other OM&A expenditures include costs associated with: common corporate functions and services (CCFS), planning, information technology, and cost of external revenues.

Hydro One further stated that CCFS includes the following functions and services: corporate management; finance; people and culture; corporate relations; general counsel and corporate secretariat; regulatory affairs; security management; internal audit; and real estate and facilities.

Other OM&A expenses include an environmental provision, indirect depreciation and other costs. Planning services include system investment and asset stewardship functions. IT activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure. Hydro One provided the following summary of common corporate costs and other allocated to distribution operations:[223]

[223] Exh. I Tab 38, Sch. SEC-70, pp. 5-6 Updated: 2018-06-11

($ Millions)

	Historic					Bridge		Test
Description	**2014 IRM**	**2015**		**2016**		**2017**		**2018**
	Actual	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Forecast**
Planning	15.0	16.4	18.4	12.2	17.8	12.3	17.6	13.3
Common Corporate Functions & Services	76.8	80.5	77.3	85.8	76.8	86.9	76.7	86.1
Information Technology	109.3	85.8	85.7	85.3	86.4	85.7	86.1	80.4
Cost of External Revenue	4.5	5.4	2.1	4.3	2.1	10.2	2.1	4.6
Other OM&A*	(111.3)	(119.0)	(124.4)	(115.5)	(128.3)	(110.2)	(127.8)	(135.6)
Total	**94.4**	**69.1**	**59.0**	**72.0**	**54.8**	**84.9**	**54.7**	**48.7**

*OEB-directed reductions for compensation (LTIP portion) and OPEB reductions as described in Exhibit Q are reflected in this line item. Includes the pension adjustment described in Exhibit C1, Tab 1, Schedule 7.

Hydro One stated that planning costs had increased from 2014 to 2015 due to the establishment of a program management office and that costs in 2016 and beyond are forecast to be lower than OEB approved amounts due to a June 2016 pension revaluation that reduced pension contribution operating expenses.

The increase in CCFS costs since 2014 is attributed primarily to higher costs for Corporate Management, People and Culture and Internal Audit, while information technology (IT) expenditures in 2017 and 2018 are trending lower on an annual basis primarily due to savings from several productivity initiatives as identified in the DSP. Historical IT spending levels were materially in line with OEB-approved forecasts.

Hydro One further stated that the cost of external revenue had been relatively flat since 2014 and that the actuals had been higher than OEB-approved amounts, mainly due to higher volumes of contestable emergency restoration work, Hydro One Remote Communities Inc. vegetation management assistance, and emergency services. OEB staff notes that the 2017 forecast of the cost of external revenue had been $4.5 million,[224] which was presumably the basis for Hydro One's conclusion that it had been relatively flat but that the actual cost of $10.2 million was well above the forecast amount.

[224] Exh. C1, Tab 1, Sch. 6, p. 2 Updated: 2017-06-07

Property Taxes & Rights Payments

Hydro One stated that it is subject to property taxes in accordance with the *Electricity Act, 1998*; the *Municipal Act; 2001*, and the *Assessment Act*. Hydro One also pays annual fees for the right to cross and/or occupy properties owned by third parties, such as railway companies and/or governmental bodies. Hydro One further stated that actual and forecast property taxes and rights payments are materially in line with approved levels. Hydro One provided the following summary of property taxes and rights payments:[225]

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual IRM	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Property Taxes	3.8	3.9	3.9	4.3	4.1	4.4	4.2	4.6
Indemnity Payments	0.5	0.4	0.5	0.0	0.5	0.0	0.5	0.0
Rights Payments	0.3	0.5	0.3	0.3	0.3	0.3	0.3	0.3
Total	**4.6**	**4.8**	**4.7**	**4.6**	**4.9**	**4.7**	**5.0**	**4.9**

OEB Staff Submission

OEB staff submits that a reduction in the $576.7 million amount of OM&A that Hydro One is proposing for recovery in the 2018 test year should be made. OEB staff believes that such a reduction should be made primarily to provide Hydro One with an additional incentive to achieve greater efficiencies in the five-year period of the proposed Custom IR plan. Specifically, as discussed in other sections of this submission, OEB staff has concerns with the subjectivity of Hydro One's internally determined productivity savings. In addition, as will be discussed in the subsequent compensation sections, OEB staff continues to believe that Hydro One's compensation levels remain too high. Finally, OEB staff is mindful of the concerns Hydro One's customers expressed regarding rate increases during the community meetings as discussed under Issue 2, which included the cost of electricity being too high and more specifically salaries at Hydro One being too high.

[225] Exh. C1 Tab 7, Sch. 4, p. 1 Filed: 2017-03-31

In determining the amount of an appropriate reduction, OEB staff is mindful of Hydro One's statement discussed under Issue 22 that its OM&A has been declining over the course of the last rate period to the point that it is meaningfully below approved levels. It is concerning to OEB staff in the context of Hydro One's current requests that it significantly underspent the OEB-approved OM&A levels even though these levels already incorporated OEB-mandated reductions in these areas.

OEB staff notes that with regard to the 2017 bridge year, the OEB-approved OM&A level was $593 million. Hydro One's initial forecast of the actual 2017 OM&A spending when the application was filed was $580.5 million.[226] When the application was updated a few months later, this forecast was adjusted down to $572.8 million.[227] The actual 2017 expenditure was $558.7 million,[228] which is a further significant reduction from the initial forecast.

OEB staff submits that this would suggest a reduction is appropriate for the 2018 test year OM&A. When Hydro One originally filed its application in March 2017, it had forecast a 2% increase in the 2018 test year from the 2017 bridge year forecast, from $580.5 million to $591.9 million. However, based on the actual 2017 value, provided in May of this year, the increase from the 2017 actual of $558.7 million to the 2018 forecast of $576.7 million was 3.2%. If the same 2% increase as was assumed in the application as filed was applied to the 2017 actual value, this would result in a 2018 forecast of $569.9 million, a reduction of $6.8 million from the 2018 level now being proposed.

OEB staff further notes that Hydro One has reduced the 2018 test year forecast from $591.9 million as filed to $576.7 million by effecting reductions in only two areas – "Customer Care" and "Common Corporate Cost and Other", in which it has recently overspent – but has made no reductions in the areas of "Sustainment," "Development," and "Operations," areas which, as have been discussed above, it has been significantly underspending. OEB staff notes in addition that Hydro One's actual total spending for 2016 was $562.6 million and in 2017 $558.7 million. If a simple average of these two most recent actuals is calculated, it is $560.7 million.

[226] Exh. C1, Tab 1, Sch. 1, p. 2 Filed: 2017-03-31
[227] Exh. C1, Tab 1, Sch. 1, p. 2 Filed: 2017-06-07
[228] Exh I, Tab 38, Sch. SEC-70, p. 2 Updated: 2018-05-04

OEB staff is also concerned that Hydro One's bringing of the call centre back in-house is not achieving any cost reductions.

OEB staff submits that as a result of the above considerations, a minimum level of reduction in Hydro One's proposed 2018 OM&A level of $17 million to $570 million should be made. Hydro One's failure to make reductions in areas where it has significantly underspent suggests that there is room for an OM&A cut in this range, as does OEB staff's subsequent discussion under Issue 40 of its concerns about the level of Hydro One's compensation costs.

OEB staff has considered Hydro One's submissions in its Argument-in-chief with respect to vegetation management. It is not OEB staff's position that Hydro One's vegetation management expenditures should be reduced from what Hydro One is proposing. OEB staff's submissions on whether the new vegetation management program should result in any impacts on the capital program are included in that section of the submission.

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?**

Background

Hydro One submitted that its proposed OM&A expenditures appropriately include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences, stating that each of these elements is considered in its proposed OM&A expenditures through the investment planning process.

Hydro One argued that system reliability had been addressed through the new vegetation management program, while service quality had been addressed through the decision to bring the call centre operations in-house. Asset condition was addressed through ongoing asset condition testing programs, while cost benchmarking is demonstrated through the use of scorecards and the benchmarking studies that were submitted as part of the application. Finally, Hydro One argued that bill impacts and customer preferences could be addressed together and were shown by noting that customers have told Hydro One that their number one concern is bill impact and Hydro One's attention to the bill impact of OM&A is best demonstrated by its request for a 2018 test year OM&A that is $16.3 million (or 2.8%) below the 2017 level approved by the OEB in the last rate application.[229]

OEB Staff Submission

OEB staff acknowledges Hydro One's argument that system reliability had been addressed through the new vegetation management program, but notes that this program is in its early stages of implementation so that it is unclear the extent to which this program will have a positive impact on reliability.

OEB staff has similar concerns about the addressing of service quality by bringing the call centre operations in-house. As discussed under Issue 38, the move in-house is still in its early days and it is not yet clear by how much it will improve service quality, nor how much, if any, cost savings it may generate.

Finally, Hydro One argued that bill impacts and customer preferences could be addressed together and were shown by noting that customers have told Hydro One that their number one concern is bill impact. Hydro One's attention to the bill impact of OM&A is best demonstrated by its request for a 2018 test year OM&A that is $16.3 million (or 2.8%) below the 2017 level approved by the OEB in the last rate application. OEB staff discussed its concerns with the OM&A levels under Issue 38. OEB staff discussed its concerns with the relationship between bill impacts and customer preferences under Issues 2 through 4.

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)?**

Background

Hydro One acknowledged[230] that its total compensation and corporate staffing strategies needed to reflect the concerns of its customers regarding the need to keep costs as low as possible, and feedback from the OEB and other external stakeholders regarding compensation and employee headcount.

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[229] Argument-in-chief, pp. 132-134.

[230] Exh. C1, Tab 2, Sch. 1, p. 1 Filed: 2017-0-31.

Hydro One stated that, in response, and guided by a company-wide commitment to aligning customer needs and preferences, responsible stewardship of the Distribution system, and rate impact, it has made gains in either reducing or limiting compensation costs and actively managing the efficiency and size of its work force, taking into account the size of its work programs.

However, Hydro One also noted that to accomplish the work program reflected in the application and deliver on the outcomes that it is committing to, it is necessary for it to attract, motivate, engage and retain a highly skilled and high performing workforce with appropriate compensation systems.

Hydro One submitted that it continues to take significant steps to ensure that its human resources related costs are appropriate and reasonable. Hydro One argued that it has taken into account and followed OEB direction and stakeholder concerns regarding human resources related costs and has made important progress in this area, while at the same time keeping in mind that Hydro One's compensation strategy is essential to it in order to attract, retain and engage the caliber of talent required to deliver on its commitments to ratepayers and its corporate strategy. Hydro One also noted that updated valuations of its pension plan and post-employment benefits plan have resulted in reductions to its revenue requirement.[231]

FTEs

Hydro One expressed its recognition of the concerns set out in previous OEB decisions with respect to rising headcount, including a concern that it has not presented its resourcing requirements on a Full Time Equivalent basis (FTE). Hydro One stated that in the application it has provided reporting on FTEs as shown below.[232]

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[231] Argument-in-chief, pp. 134-135.
[232] Exh. C1, Tab 2, Sch. 1, Table 1, p. 9 Filed: 2017-03-31.

Full Time Equivalents (FTE) - 2017 to 2022

		2017	2018	2019	2020	2021	2022
Regular	MCP	679	675	671	669	668	668
	Society	1375	1380	1376	1370	1363	1363
	PWU	3480	3444	3423	3413	3403	3395
	Total	**5534**	**5499**	**5470**	**5452**	**5434**	**5426**
Non-Regular	MCP	29	28	28	28	27	27
	Society	51	46	41	41	41	41
	PWU	165	140	138	138	137	137
	Total	**245**	**214**	**207**	**207**	**205**	**205**
Casual	PWU HH	1374	1465	1400	1401	1407	1408
	Casual Construction	1428	1428	1428	1428	1428	1428
Total FTE's		**8581**	**8606**	**8505**	**8488**	**8474**	**8467**

Hydro One stated that in the future it expects to incorporate the FTE metric into its business planning and performance management processes.

Hydro One also noted that the above table illustrates that total regular FTEs and total FTEs in 2022 are expected to be 2.0% and 1.3% lower respectively than in 2017.

Management Compensation

Hydro One stated that in order to achieve its commercial objectives, the independent Board of Directors had determined that senior managers with proven track-records of delivering the targeted commercial objectives were needed. Hydro One further stated that the individuals with these skills have been added to its senior leadership team and have been empowered by the Board of Directors in place at the time the application was filed..

Hydro One explained that to achieve these commercial objectives it had become critical that it design a compensation structure to attract, motivate, and retain high-performing talent to execute on the corporate strategy. To assist with this work, Hydro One engaged Willis Towers Watson to undertake competitive market assessments and sought advice from and Hugessen Consulting to determine the basis for the components of a new management compensation program. Willis Towers Watson completed two compensation benchmarking studies and Hugessen Consulting completed an executive compensation benchmarking study. All three of these studies were included as part of the application.

Hydro One concluded that its management compensation strategy is driving a cultural shift to commercial company norms, with new shareholder expectations and an increased focus on customers, productivity, efficiency and accountability.

Hydro One submitted that, as explained at the oral hearing, its management compensation strategy is illustrative of its new approach to compensation. Hydro One stated that it is focused on pay for performance where successful outcomes are rewarded and there are no generalized compensation increases for management employees. Hydro One noted that a significant portion of compensation is variable or at-risk pay, with a greater percentage of compensation being variable the more senior the role. Hydro One stated that its compensation programs are based on independent compensation advice and best practices and are aligned with compensation principles approved by the Hydro One Board of Directors. Hydro One also noted that in response to concerns expressed regarding its defined benefit pension plan, it had closed this plan and introduced a less costly defined contribution pension plan for all new management employees and in addition, employees are contributing more to the cost of their pension.[233]

Unionized Compensation

Hydro One noted that approximately 90% of its employees are represented by a trade union and it is legally required to negotiate collective agreements with the employees' bargaining representatives. Hydro One stated that it had inherited collective agreements from Ontario Hydro, which established terms of employment and that these agreements had established a 'floor' upon which future negotiations are based. Hydro One further stated that while legacy collective agreements continue to strongly influence current Hydro One collective agreements, it has done much to change the status quo including successfully incrementally reducing costs and/or increasing productivity through collective bargaining.

Hydro One stated that its Human Resources strategy is to negotiate fair and reasonable collective agreements to foster and promote healthy union–management relationships. In

[233] Argument-in-chief, p. 135.

this context with respect to labour agreements, more so than commercial contracts, parties must also consider their longer term relationship. Hydro One concluded that it has been able to achieve reasonable settlements with moderate incremental cost reductions and increased flexibility in a variety of areas in every round of collective bargaining since 2001.

On July 11, 2018 Hydro One filed its Memorandum of Agreement (MoA)[234] with the Power Workers' Union for a two year collective agreement running from April 1, 2018 to March 31, 2020. Hydro One noted that the wage escalation in the MoA is higher than the wage escalation assumed in the application, but as indicated during the oral hearing, Hydro One is not seeking to adjust its applied-for revenue requirement in light of the MoA. Hydro One had assumed a one percent PWU wage escalation rate in the application, but the wage escalation rates in the MoA were 1.8% effective April 1, 2018, 2.0% effective April 1, 2019 and 0.6% effective January 1, 2020. The revenue requirement effects of the contract were estimated to range from a low of $1 million in 2018 to a high of $2.35 million in 2022.

Overall Compensation Costs

In the application as originally filed, Hydro One provided information on the actual total compensation for distribution operations for the 2014 to 2016 period and for the 2017 bridge year and 2018 to 2022 test years:[235]

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Dx Compensation	628,687,087	625,297,510	639,004,626	606,748,484	637,778,506	642,530,718	631,275,350	616,248,742	622,009,219

Hydro One noted that over the test period, total compensation for the distribution business increased by 2.5% whereas the distribution work program is expected to increase by 19%, which Hydro One stated was an indicator of its increasing productivity.

[234] EB-2017-0049 – Hydro One Networks Inc.'s Distribution 2018-2022 Rate Application – Memorandum of Agreement with PWU and Variance Analysis, July 11, 2018.
[235] Exh. C1, Tab 2, Sch. 1, p. 48 Filed 2017-03-31.

Hydro One also noted that in the OEB's Decision on its previous distribution rates application,[236] it had been directed to undertake a compensation study similar to what had been undertaken in that application to allow benchmarking to comparable companies. Hydro One stated that as a result four total compensation studies had been conducted by Mercer Canada with the 2016 study provided as part of the application.[237]

In April 2018, Hydro One filed an updated version of the Mercer compensation study.[238] The Mercer study mandate is described as "to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group."[239]

Mercer stated that this study was conducted in 2008, 2011, 2013 and 2016, and was repeated, following a similar methodology, in 2017. On an overall weighted average basis, for the jobs Mercer reviewed in 2017, Hydro One is positioned approximately 12% above the market 50th percentile (P50 or median). In comparison to the 2016 study, Hydro One's overall weighted average positioning has decreased from 14% above the market total compensation 50th percentile. Mercer suggested that the shift in Hydro One's competitive position towards the median is notable given that the peer group, like Hydro One, has worked to reduce labour costs as a response to both the substantial economic downturn beginning in 2008 and expectations of key stakeholders over the entire period the compensation cost benchmarking studies have been conducted (2008 – 2016).[240]

The table below summarizes the results of the 2017 Compensation Cost Benchmarking Study compared to the results of the 2016, 2013, 2011 and 2008 study.[241]

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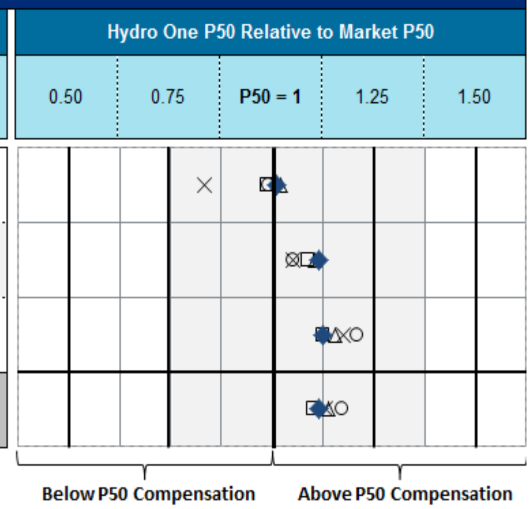
[236] EB-2013-0416.
[237] Exh. C1, Tab 2, Sch. 1, Attach. 5 Updated 2017-06-07.
[238] EB-2017-0049 "Additional Compensation Evidence," April 20, 2018.
[239] Mercer "Compensation Cost Benchmarking Study Hydro One Networks Inc.," 04 April 2018, p. 1.
[240] *Ibid*, pp. 3-4.
[241] *Ibid*, p. 5.

			Total Remuneration (Current)				
			Multiple of P50				
	Hydro One Group	*# of Hydro One Incumbents*	2017 ◆	2016 △	2013 □	2011 ╳	2008 ○
Weighted Average	Non-Represented	*172*	**1.01**	1.02	0.99	0.83	0.99
	Energy Professionals	*560*	**1.12**	1.11	1.09	1.05	1.05
	Trades and Technical	*2,478*	**1.12**	1.16	1.12	1.18	1.21
	Overall	***3,210***	***1.12***	***1.14***	***1.10***	***1.13***	***1.17***



Legend
◆ 2017 Hydro One Position Relative to Market
△ 2016 Hydro One Position Relative to Market
□ 2013 Hydro One Position Relative to Market
╳ 2011 Hydro One Position Relative to Market
○ 2008 Hydro One Position Relative to Market

Pension Costs

On September 14, 2017, the OEB released its *Report on the Regulatory Treatment of Pension and Post-Employment Benefit (OPEB) Costs* (the Report). This Report describes the policy of the OEB for the regulatory treatment of the cost of pension and OPEBs incurred by rate-regulated energy utilities in Ontario and specifically addresses the manner in which those costs are recovered from customers. The Report establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications. It requires utilities that propose to set rates using a method other than accrual to support such a proposal with evidence that gives consideration to factors such as providing value to customers, fairness, intergenerational equity, and other principles and practices enunciated in this Report.

As part of the current application, Hydro One has proposed to recover its test period pension costs on a cash basis. In support of this proposal, the utility asserted that it believes that the cash method is more beneficial to its customers than the accrual method because it results in a lower cost recovered though rates, it is more predictable, and the OEB has historically accepted the cash method as the basis for the recovery of its pension costs. In response to OEB staff interrogatories, Hydro One further provided a historical analysis that compared the amounts collected in rates on a cash basis compared to what would have been collected in rates had the accrual method been used. Although the results of this analysis indicated that the rates under either method would have been quite consistent, on a cumulative year-to-date basis, it showed that the cash method has historically provided more value to the ratepayers.[242]

OPEB Costs

Hydro One has proposed to recover its OPEB costs on an accrual basis, which is consistent with the findings of the OEB's Report on the Regulatory Treatment of Pension and OPEB costs. OPEB costs are addressed further in OEB staff's submission on Issue 58.

OEB Staff Submission

Compensation Other Than Pension Costs

In early May 2018, Hydro One filed updated compensation costs on a transmission, distribution and total basis. OEB staff has summarized the results of this filing in the table below:[243]

	$ Thousands			%			Yr over yr % change		
	Trans	Dist	Total	Trans	Dist	Total	Trans	Dist	Total
2013	476043	595670	1071713	44.4	55.6	100			
2014	522548	596623	1119171	46.7	53.3	100	9.77	0.16	4.43
2015	517129	602556	1119685	46.2	53.8	100	-1.04	0.99	0.05
2016	475921	569705	1045626	45.5	54.5	100	-7.97	-5.45	-6.61
2017A	508122	555417	1063539	47.8	52.2	100	6.77	-2.51	1.71
2018T	525558	609690	1135248	46.3	53.7	100	3.43	9.77	6.74

OEB staff notes that the above table shows that there is an almost 10% increase in distribution compensation costs in the 2018 test year when compared to 2017 actual. OEB staff further notes that this is partially because compensation costs increased by 6.74% overall in the 2018 test year as compared to 2017 actual but also because the allocation of these costs to distribution operations also increased from 52.2% in 2017 to 53.7% in the 2018 test year.

[242] EB-2017-0049, Exhibit 1, Tab 40, Schedule Staff-211.
[243] Exh. I-40-SEC 85, Attach. 1, p. 1 Filed: 2018-05-04.

OEB staff considers this increase to be excessive given currently expected increases in the inflation rate and as further support for the overall reduction in the test year OM&A which OEB staff recommended be made in the previous section.

In making this recommendation, OEB staff is mindful of the improvement relative to its comparator group that Hydro One has demonstrated in the 2017 Mercer study in which Hydro One has moved from approximately 12% above the P50 in comparison to the 2016 study's level of 14%. OEB staff first notes that there has been quite a bit of variability in Hydro One's performance over the past 10 years, being 17% above the median in 2008, dropping to 10% above in 2013 and then increasing to 14% above in 2016. When asked about the improvement from 14% above the median in 2016 to 12% in 2017, Mr. Morris of Mercer appeared to place significant qualifications on the extent of the improvement.[244]

> MR. SIDLOFSKY: Now, it's clearly your suggestion that moving from 14 percent above median to 12 percent above median is an improvement for the company from 2016 to 2017, correct?
>
> MR. MORRIS: It's certainly an improvement. There are two snapshots in time. There are two datasets and two analyses that reach that conclusion, frankly. So based on the information that we used in our analysis for the benchmarked jobs, for the design of Hydro One programs, and applying a consistent analysis and industry standard practice, we've concluded that relative to the market median, the number is lower.
>
> Now, if we were to say in the judgment around competitiveness that organizations exercise plus and minus 5 percent in judgment, the outcomes would overlap, if you were to cast those ranges. But the hard numbers themselves did diminish.

[244] Transcript, Vol. 4, p.100 L25 to p. 101 L13.

In any event, OEB staff is concerned that with Hydro One being 12% above the median in 2017 when it was only 10% over in 2013 represents uncertain progress at best. OEB staff submits that a level of 12% above the market median is still too high, especially given the number of years Hydro One has now been working to bring these costs more in line with market levels.

In this context, OEB staff notes that the challenges ahead for Hydro One in keeping its compensation costs under control appear to be emphasized by the terms negotiated on the new PWU contract which resulted in higher costs than Hydro One had forecast in the application. While Hydro One is not seeking recovery of these additional costs in the current application, they will exert upward pressure on compensation costs for future applications.

For all of the above reasons, OEB staff believes that its recommendation to reduce the test year OM&A level from that which Hydro One is requesting is supported by the above assessment of compensation costs.

OEB Staff Submission

Pension Costs

OEB staff notes that the evidence provided by Hydro One in support of its continued use of the cash method as the basis to recover its pension costs meets the requirements of the OEB's Report. OEB staff further notes that the OEB's Report clearly states that the intended practice of maintaining a consistent method used to determine recovery over time may be one reason for not adopting the accrual method for rate setting. Stability and predictability in regulation are desirable unless unintended and undesirable effects occur.[245] Hydro One has historically recovered its pension costs on a cash basis and its ratepayers have historically been better-off under the cash method. Therefore, OEB staff submits that the continued use of the cash method by Hydro One to recover its pension costs is justified.

Amount Sought for Recovery in the Test Period

As noted in the above section, Hydro One recovers its pension costs on a cash basis. The cash basis represents the annual cash contributions that the utility is required to

[245] EB-2015-0040, Report of the OEB on the Regulatory Treatment of Pension and OPEB Costs, p. 8.

make to the pension plan as calculated by an actuary. The actuary calculates these contributions in accordance with the requirements of the *Pension Benefits Act*. This Act was designed to ensure that a pension plan is adequately funded and prescribes that an employer must at a minimum contribute an amount to the pension plan that is sufficient to cover the employer's normal actuarial cost plus the amount of any special payments that may be required. The employer's normal actuarial cost refers to the cost of the benefits that are earned by an employee in a particular year, and special payments refer to additional contribution amounts that an employer is required to make when the pension plan is in a deficit position in order to eliminate this deficit.

Hydro One has sought to recover the following amount in respect to its pension costs for the test period[246]:

2018 Forecast Pension Costs ($ Millions)

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	11	17	2	30
Capital	21	20		41
	32	**37**	**2**	**71**

OEB staff notes that the actuarial valuation that was filed by Hydro One to underpin its test period pension costs indicates that its contribution requirement for the test period is in fact zero[247], compared to the $37 million that Hydro One is actually seeking. Put another way, the actuary has determined that Hydro One does not have to make any employer contributions to its pension plan, however Hydro One is electing (at its own discretion) to still make employer contributions of $37 million.

The actuary had determined that employer contributions are not required in the test period because Hydro One's pension plan was in a surplus positon of $434 million[248] at the time the valuation was performed (on a total company basis). This means that the pension plan had more money than it needed, or more specifically, the assets of the pension plan exceeded the liabilities by $434 million. The $37 million in contributions that Hydro One has sought to recover for the test period (or $71 million for Hydro One as a whole) represents the contributions that Hydro One would have had to make to the

[246] Exh. C1, Tab 2, Sch. 2, Table 1.
[247] Exh. C1, Tab 2, Sch. 2, Attach. 1 (Section 3).
[248] Exh. C1, Tab 2, Sch. 2, Attach. 1 (Section 1.2).

pension plan had it not been in a surplus position. However given the surplus, the actuary has instead allocated these surplus funds in the pension plan to offset Hydro One's contribution requirement. Holding all else equal, there is enough surplus in the pension plan to offset the minimum employer contribution requirements for the entire five-year term of the application, with some buffer to spare.[249]

Given that the actuary has determined that Hydro One does not have to make any employer contributions to the pension plan in the test period, combined with the fact that the surplus in the pension plan appears to be large enough to offset the Hydro One's contribution requirements over the 5-year application term (holding all else equal), OEB staff submits that the pension costs included in the test period revenue requirement should be reduced from $37 million to zero.

During OEB staff's cross examination on this topic, Hydro One provided the following explanation as to why it had elected to still make employer contributions to the pension plan when their actuary did not require them:

> MR. CHHELAVDA: In our mind it is the prudent thing to do because in the event that you take a funding holiday you potentially run the risk, based on a lot of factors, fund performance, macroeconomic conditions, that you may have an adverse event that occurs, and then you may be subject to special payments or a going-concern payment, so you have to look -- when you are looking at funding requirements I believe -- my view is that you have to look at -- it's not a one- or two-year view; you have to get a longer-term view.[250]

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[249] Holding all else equal, employer contributions over the application term would be $71 x 5 = $355 million. Therefore the current surplus of $434 million is more than sufficient to offset these estimated costs over the application term.
[250] Transcript, Vol. 4, p. 78 L21 – p. 79 L1.

OEB staff submits that Hydro One's decision to make employer contributions to the pension plan is based on speculation. The reality is that no one can predict how the pension plan will perform in the future. The plan's performance is dependent on many different variables and assumptions, such as discount rates, mortality rates, and economic factors, making it virtually impossible to predict with any accuracy. It is possible that the scenario presented by Hydro One in the above excerpt could materialize. However, it is also just as possible that the pension plan remains in a surplus position and special payments are never required. Ultimately, ratepayers should not be asked to fund based on the possibility of a future change in the market. If the market shifts and special payments are required in the future, then ratepayers will be asked to fund those at that time[251]. The revenue requirement should be based on the best available information at the time, which in this case is the current actuarial valuation that indicates that no employer contributions are required.

OEB staff further submits that Hydro One already has a variance account in place to capture the difference between the pension costs built into rates and what is actually paid out. Therefore in the event that something does change during the application term, Hydro One will be made whole for the difference through this variance account. Hydro One acknowledged as such during the oral hearing:

> MR. SIDLOFSKY: If circumstances change rapidly and you had to make special payments, how would you recover those?
>
> MR. CHHELAVDA: Those special payments would be recovered. We would make an application in -- well, the typical process is you'd have valuation, then you would make a -- you would actually make those contributions. Right now, we have a pension variance account, so the cost would be parked there to be disposed of at a future point in time.[252]

[251] Hydro One had indicated that the ratepayers were previously asked to make special payments within the last two years – Transcript Vol. 4 p.79.
[252] Transcript, Vol. 4, p.79 L19 28.

During OEB staff cross examination, Hydro One further stated the following regarding Hydro One's contribution requirements to the pension plan:

> MR. CHHELAVDA: One thing I want to add is, there are estimated member contributions, and if you recall earlier in the day, I did mention that Hydro One does not have -- the way our union contracts are written, Hydro -- the employer contributions cannot be less than the employee contribution, so given those set of constraints that we have, I -- my view is I do not believe Hydro One could take a full funding holiday. You would still have to contribute equal to the employees' contribution[253].

The above infers that a full employer funding holiday may not be possible as a result of existing union agreements. Under such a scenario, it is not unreasonable to allow Hydro One to recover what it is required to contribute as a result of their collective agreements. However, OEB staff notes that currently there does not appear to be any information on the record that breaks out the total employee (member) contributions between the distribution and transmission businesses in order to calculate what the test period employer contribution would be under the above noted scenario. If the OEB decides that recovery of contributions will be allowed and limited to the amounts embedded in the collective agreements, then Hydro One could provide those amounts as part of the draft Rate Order process.

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)?**

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[253] Transcript, Vol. 4, p. 78 L2-L10.

Background

In the OEB's previous decision on Hydro One's distribution rates, the OEB expressed concerns about the compensation evidence Hydro One had filed in that application, stating that.[254]

> "Hydro One did not provide sufficient evidence is support of its proposed compensation spending. The company did not demonstrate that the market requires the level of compensation proposed in order to attract and retain the necessary employees."

On December 20, 2016, in the transmission proceeding,[255] Hydro One filed Undertaking J10.2, which provided a breakdown of transmission-only compensation costs. In its February 16, 2017 Reply Argument, Hydro One agreed to file a table similar to that contained in Undertaking J10.2 in its next transmission and distribution rates applications.[256]

In its September 28, 2017 Decision and Order[257] in the transmission proceeding, the OEB acknowledged Hydro One's agreement to file a table similar to that contained in Undertaking J10.2 in its next transmission and distribution rates applications. In its findings with respect to compensation in the transmission proceeding, the OEB issued the following directions to Hydro One with regard to compensation evidence in the current distribution proceeding:

> "The OEB expects Hydro One to file this complete total compensation information in the distribution rates proceeding as soon as possible. The OEB expects that the information to be filed will include the following:
>
> a) Tables comparable to the year-end payroll tables in the Transmission Payroll Tables for each of the years 2014 to 2018 containing total compensation information that reconciles with the combined totals of the amounts for each of the years 2014-2018 allocated to transmission shown in Undertaking J10.2 and the amounts shown for distribution in the Distribution Payroll Tables

[254] EB-2013-0416/EB-2014-0247 Decision March 12, 2015, p. 24.

[255] In this section, OEB staff is largely reiterating its December 18, 2017 "OEB Staff Submission on Compensation Evidence" updated where necessary for developments subsequent to the filing of this submission.

[256] EB-2016-0160 – Hydro One Reply submission, February 16, 2017, at p.83, para. 277.

[257] EB-2016-0160 – Decision and Order, September 28, 2017, Revised November 1, 2017, at p.53.

b) Within these total compensation tables, for each of the line item amounts and for each year, the total number of employees in a manner that reconciles with the total number of employees information presented in Transmission Payroll Tables

c) Beside the "Total Number of Employees" information described in item (ii), the total company full time equivalent (FTE) information for each of the years 2014- 2018 in a format similar to that shown in EB-2017-0049 Exhibit C1/Tab 2/Schedule 1, Table1

d) In the total compensation tables, the allocation of total compensation between capital and Operating, Maintenance and Administration (OM&A) for each of the years 2014-2018 in a manner comparable to that shown for transmission only in Undertaking J10.2

e) As part of the total compensation table, the Pension and OPEB amounts for distribution for each of the years 2014-2018 in a table similar to the table to that effect contained in Undertaking J10.2

f) A revision of the format used in Undertaking J10.2 to reflect the format of the total compensation tables described in items a) to e)

g) An exhibit that shows how the allocation factors used to allocate the total compensation amounts between transmission and distribution are derived. The OEB directs the above information to be presented in the distribution rates proceeding on a basis that is consistent with the combined year-end payroll information for the transmission and distribution business segments."

OEB Directions on Compensation in the Current Distribution Proceeding

On October 11, 2017, Hydro One filed a letter in the current proceeding, enclosing updated evidence on compensation as requested in the transmission proceeding Decision and Order. In that letter, Hydro One indicated that it had changed its methodology for reporting compensation in the distribution proceeding compared to that used in its transmission evidence. Hydro One also noted that the new methodology for reporting compensation could result in a more accurate reflection of compensation but would also make it impossible to compare the compensation evidence from the transmission proceeding to that of the distribution proceeding.

The OEB acknowledged the Hydro One letter in Procedural Order No. 2, and indicated that it did not intend to rehear the same evidence related to compensation in this distribution proceeding that it did in the transmission proceeding.

As a result, and to determine the extent to which the OEB would consider compensation in this proceeding, the OEB directed Hydro One to explain the differences among what it proposed for compensation in the transmission proceeding; what the OEB decided with regard to compensation in the transmission proceeding; and what is in its compensation evidence in the current proceeding. Specifically, Hydro One was required to file its total compensation, and allocation to distribution and transmission, using the methodology used in the transmission proceeding and shown in Undertaking J10.2 in that proceeding, filed December 20, 2016.

The OEB specified that the filing should include the years 2013 to 2018 as provided in Undertaking J10.2 to allow the identification of any differences between the compensation in this proceeding and the compensation in the transmission proceeding not caused by the change in methodology; such as the impact of changing the allocation of compensation between transmission and distribution to reflect the business plan underpinning the current application. Hydro One was expected to comment on any differences.

In addition, intervenors and OEB staff were provided the opportunity to review the evidence submitted by Hydro One and to provide any comments on how the OEB should scope its review of the compensation issue.

Hydro One Filings on Compensation in the Current Proceeding

Hydro One has made a number of filings related to compensation in this proceeding:

1) The original compensation evidence, filed on March 31, 2017 as Exhibit C1/Tab 2/Schedule 1, and specifically Appendix B thereto, showing a table of historical and forecast distribution compensation from 2014 to 2022.

2) The October 11, 2017 filing, submitted in response to the OEB's directions in its September 28, 2017 Decision and Order in the Transmission Proceeding, identified as Attachment 6 to Exhibit C1/Tab 2/Schedule 1. That filing showed compensation costs for both transmission and distribution from 2014 to 2022.

3) The December 12, 2017 submission, filed in response to the OEB's directions (identified above) in Procedural Order No. 2. Two further attachments were filed:

    a) Attachment 7 to Exhibit C1/Tab 2/Schedule 1, which outlines the differences in methodologies used to calculate compensation costs in this proceeding and in Hydro One's 2017-2018 transmission rate proceeding.

b) Attachment 8 to Exhibit C1/Tab 2/Schedule 1, which is Hydro One's total compensation, and allocation to distribution and transmission, using the methodology shown in Undertaking J10.2 of Hydro One's 2017-2018 transmission rate proceeding.

In its December 12, 2017 submission, Hydro One outlined the differences in how compensation information was produced in the past. Hydro One advised that in previous years, and as shown in its original evidence in the transmission proceeding, pension and OPEB burdens were not included in the overall compensation totals. Those were added later in Hydro One's response to Undertaking J10.2, for transmission only.

More particularly, in Undertaking J10.2 in the transmission proceeding, Hydro One:

- applied the "labour content" method from the Black and Veatch study "Review of Overhead Capitalization Rates"[258] to allocate costs to the transmission compensation data
- reflected costs only for those employees on payroll on December 31st

Attachment 6 to Exhibit C1/Tab 2/Schedule 1, filed in the current proceeding on October 11, 2017, included both transmission and distribution compensation. Hydro One advised that that attachment:

- uses the expansive definition of "total compensation", consistent with Undertaking J10.2 in the transmission proceeding
- reflects total compensation costs for full years, rather than a point in time, which is not consistent with Exhibit J10.2
- refines the allocation of casual employee compensation based on management's expertise regarding the relative contribution of casual employees to the transmission and distribution work programs
- reflects actual 2016 compensation rather than the forecast used in J10.2
- uses an updated actual allocation between transmission and distribution as compared to a forecast used in J10.2, with a shift of cost to distribution and an equal offset to transmission
- reflects the Distribution Business Plan (of December 2016).

[258] EB-2016-0160, Exhibit B1-3-10-1.

In addition, the Attachment 6 filing includes a change in how the Black and Veatch allocation is applied: in the J10.2 evidence it was applied to all employees. However, in Attachment 6 it is only used for regular employees while costs for casual employees are allocated by the percentage used by each line of business and the use of management expertise.

Hydro One submitted[259] that it has listened carefully to the concerns of parties in past proceedings in regard to its compensation evidence and that it had worked to respond to these concerns in the data it has provided in the application. Hydro One referred to the explanation below from the oral hearing to explain where it stood on this matter.[260]

> Specifically, we now show total compensation annually by our transmission and our distribution businesses and a consolidated view. We also show year-end compensation annually for our transmission and distribution businesses, and a consolidated view. We have included more cost compensation inputs to better reflect total compensation at Hydro One. We now show head count, full-time equivalence, and year-end head count numbers now. We've refined our methodology for allocating casual employee compensation in order to reflect a more accurate allocation between our transmission and our distribution businesses.
>
> And while this can be quite overwhelming, for sure, we do have an explanation reconciling the different approaches to showing our payroll data, and that is set out in Exhibit C1, tab 2, schedule 1, attachment 7, pages 4 through 8.

[259] Argument-in-chief, p. 136.
[260] Transcript, Vol. 3, p. 9 L 21 to p.10 L 7.

OEB Staff Submission

OEB staff has made its submissions as to whether or not Hydro One has shown efficiency and value for compensation costs under Issue 40 above.

With respect to the matter of whether or not Hydro One has demonstrated improvements in presenting its compensation costs, especially in the context of the expectations outlined by the OEB in the most recent transmission and distribution decisions, OEB staff first notes the complexity of the record on this matter as summarized above.

OEB staff considers that the requirements established in the decision and order in the Transmission Proceeding for the distribution rate proceeding[261] (distribution presentation requirements) are critical in assessing the extent of the improvements Hydro One has demonstrated in presenting its compensation costs.

On this basis, OEB staff submits that Hydro One does not yet appear to have a consistent template for presenting all of the information outlined by the OEB in the distribution presentation requirements, and this makes for an often confusing variety of tables. As an example, the information filed by Hydro One on October 11, 2017 includes headcount and FTE information, but the tables filed in the format of transmission proceeding Undertaking J10.2 subsequently on December 12, 2017 and May 4, 2018 do not, which makes it hard to get a clear and consistent view of Hydro One's compensation levels along with the accompanying headcount.

Hydro One noted in the October 11, 2017 that it has not used FTEs in past rate filings.[262] As noted previously in the discussion in the compensation section of this submission, Hydro One stated in the application that in the future it expects to incorporate the FTE metric into its business planning and performance management processes. OEB staff considers it to be important for Hydro One to complete this process before it can be said that Hydro One has demonstrated improvements in its compensation costs presentation sufficient to meet the OEB's expectations. OEB staff further submits that Hydro One should develop a standardized presentation of compensation costs superseding that of Undertaking J10.2 that meets all of the OEB's stated requirements and which would be used in future transmission and distribution filings. Once Hydro One has accomplished this, OEB staff would be of the view that Hydro One had demonstrated sufficient improvements in its compensation cost reporting to meet the OEB's requirements.

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[261] Summarized in the Background section above.
[262] Exh. C1-02-01, Attach. 6, p. 9 Filed 2017-10-11.

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?**

In accordance with the OEB's letter of August 3, 2018,[263] OEB staff is making no submissions on this 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?**

Background

Hydro One stated that it allocates common corporate costs and other OM&A costs to its distribution and transmission businesses and to each Hydro One affiliate based on clearly articulated shared functions and services and an established cost allocation approach based on cost causality principles.[264]

Hydro One added that since 2004, in connection with each cost of service application, it had commissioned a study by B&V to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. Hydro One stated that the adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. Hydro One further stated that as part of the 2016 study, the cost drivers used to allocate the common corporate costs in the previous distribution proceeding were updated to incorporate current information.

Hydro One stated its acceptance of the results of the 2016 B&V study as a reasonable and equitable approach to the assignment of common corporate costs among the business entities using the common services. Hydro One noted that this methodology is

[263] Ontario Energy Board, *Hydro One Networks Inc. 2018-2022 Distribution Rates Application, EB-2017-0049 Executive Compensation,"* August 3, 2018.
[264] Exh. C1 Tab 4 Sch. 1, p. 3 Filed: 2017-03-31.

based on the R. J. Rudden Associates Study that the OEB had accepted in a previous rate decision.[265]

OEB Staff Submission

OEB staff submits that Hydro One has provided sufficient justification to demonstrate that the methodologies used to allocate common corporate costs and other OM&A costs to the distribution business for 2018 and further years are appropriate. As noted under Issue 31 a portion of common corporate costs related to management of non-regulated activities has not been allocated to the regulated businesses; which is in keeping with the decision in the transmission proceeding.[266]

G: REVENUE REQUIREMENT

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

Background

Hydro One's total depreciation and amortization expenses are summarized in the application in the table below:[267]

Description	Historic				Bridge	Test				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Depreciation Expenses	313.0	336.2	349.0	359.8	362.6	379.3	401.6	414.3	434.2	450.5
Total Amortization Expenses	8.5	11.1	10.5	12.0	17.8	17.3	16.2	18.8	18.6	17.4
Exclude Other Regulatory Amortization	0.5	1.1	1.9	3.2	3.7	4.1	4.3	4.5	4.7	4.9
Total	321.0	346.2	357.6	368.7	376.7	392.6	413.5	428.6	448.1	463.0

[265] RP-2005-0020/EB-2005-0378 and EB-2016-0160.
[266] EB-2016-0160.
[267] Exh. C1, Tab 6, Sch. 1, p. 3, Table 1 Updated: 2017-06-07.

Hydro One stated that in its 2005 distribution rates proceeding,[268] its depreciation rates had been approved by the OEB based on an independent depreciation study completed by Foster Associates Inc. (Foster Associates) dated June 2005. Hydro One added that costs flowing from the depreciation study were accepted for the purpose of establishing Hydro One distribution's rates revenue requirement in 2006.[269]

Hydro One noted that in 2013, Foster Associates had conducted an additional depreciation study which recommended continuation of the historical depreciation rates for purposes of the rates revenue requirements for the years 2015 to 2017 and the OEB had accepted this approach.[270]

In 2016, Hydro One requested that Foster Associates prepare a new depreciation study covering Hydro One's distribution and common assets for the 2018 – 2022 period. Using Hydro One's historically approved depreciation rates, total depreciation and amortization expense for the 2018 test year would be $392.6 million as provided in the above table.

However, Hydro One stated that if the depreciation rates found in the 2016 Foster Associates study were adopted, the depreciation and amortization expense for the test year 2018 would increase by $21.9 million to $414.5 million. However, Hydro One stated that the application reflects the continued use of the 2013 depreciation study to calculate depreciation costs in 2018-2022.

Hydro One justified this approach on the basis that the Foster Associates study is based on the expected remaining life of an existing pool of assets at a point in time. Future capital spending will result in additions to existing pools of assets. These additions are reasonably expected to change the average expected remaining life of some or all of these pools of assets, and the applicable depreciation rates. These changes can result in volatility in depreciation expense.

Hydro One noted that the 2016 Foster Associates study would create, if implemented, increased depreciation rates and expense over the 2018 to 2022 rate setting period. However, planned capital expenditures over the five year term of the application may result in an increase in the average remaining life of these asset pools, requiring a future

[268] RP-2005-002/EB-2005-0378.
[269] Exh. C, Tab 6, Sch. 1, p.1 Updated: 2017-06-07.
[270] EB-2013-0417.

decrease in depreciation rates and expense. Therefore, Hydro One stated it has decided to maintain its existing depreciation rates instead of adopting the rates proposed in the 2016 Foster Associate study to avoid these potential fluctuations in depreciation rates and the expenses recovered through rates. Hydro One stated that its decision was supported by Foster Associates as well as its external auditor who also accepts this position.

OEB Staff Submission

OEB staff submits Hydro One's proposed depreciation expense for 2018 and further years is appropriate as it is justified by the assessments undertaken and helps to mitigate customer rate increases.

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

Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable? (Issue 54)

Background

Hydro One stated that external revenues are earned through the provision of specific services to customers and third parties and through joint use of Hydro One's distribution assets by third parties. These revenues offset Hydro One's distribution revenue requirement, reducing the required revenue to be collected from ratepayers.[271]

Specific Service Charges

Hydro One stated that a significant portion of its external revenue is generated by charging specific service charges for miscellaneous services over and above the standard level of service as defined in the DSC. Each of these services has an OEB-approved fixed rate and is charged to a customer based on a customer's request or as the result of a customer's action or inaction that would impose a cost on Hydro One's distribution customers.

Hydro One noted that its specific service charges have been held fixed for the past ten years, but that in response to OEB direction from the previous distribution rates

[271] Argument-in-chief, pp. 141-144.

proceeding, it had completed an extensive year-long time study of the work and costs to provide miscellaneous services. Hydro One submitted updated specific charges that were, with some exceptions, based on this study and has also updated its telecom pole attachment charge in response to the OEB's recent direction on this matter.[272]

External Revenue

These revenues are generated by charging specific service charges for miscellaneous services or from other revenues, not associated with OEB-specific service charges, that are based on an estimated cost of providing the external work calculated using standard labour rates, equipment rates, material surcharge and overhead rates as well as forecast volumes that Hydro One believes are reasonable.

Hydro One provided information on its total external revenues as shown in the tables below.[273]

($ Millions)

Description	Historic					Bridge	
	2014	2015		2016		2017	
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved
Regulated Revenues	25.4	37.7	39.4*	51.6	40.4*	39.0	42.5*
Unregulated Revenues	6.5	6.5	6.7	7.0	6.6	6.8	6.5
Sub-Total External Revenue	**31.9**	**44.2**	**46.1**	**58.6**	**47.0**	**45.8**	**49.0**
Standard Supply Service Charge	3.7	3.7	3.6	3.6	3.7	3.9	3.7
Total External Revenue and Other	**35.6**	**47.9**	**49.7**	**62.2**	**50.7**	**49.7**	**52.7**

*Updated approved amounts reflect the EB-2013-0416 Draft Rate Order decision for miscellaneous charges revenue and the EB-2015-0141 decision for pole attachment revenue.

Hydro One updated its forecast External Revenue as a result of updates provided during the oral hearing.[274] These updates are incorporated in the table below:

($ Millions)

[272] Decision and Procedural Order No. 6, May 18, 2018.

[273] Exh E1, Tab 1, Sch. 2, p. 2 Updated: 2017-06-07.

[274] Undertaking J 11.2.

Description	Test				
	2018	2019	2020	2021	2022
	Forecast	Forecast	Forecast	Forecast	Forecast
Regulated Revenues	39.3	40.2	40.4	41.3	41.6
Unregulated Revenues	3.8	3.8	3.8	3.8	3.9
Sub-Total External Revenue	**43.1**	**44.0**	**44.3**	**45.1**	**45.4**
Standard Supply Service Charge	3.9	3.9	4.0	4.0	4.0
Total External Revenue and Other	**47.0**	**47.9**	**48.2**	**49.1**	**49.4**

Hydro One noted that regulated revenues had been updated to reflect it no longer introducing some specific service charges, which would have the effect of a shift of approximately $341,000 from forecasted 2018 external revenue to Hydro One's rates' revenue requirement, which Hydro One stated would not materially impact its customers.[275]

Hydro One futher explained that other reductions to external revenue related to its decision to propose to maintain the currently approved rate it charges for disconnections and reconnections at the meter, which is a change from what it had proposed in the application as filed. Hydro One stated that this change would result in a reduction of $1.3 million in external revenue. Hydro One also incorporated other updates including the impact of the Fair Hydro Plan on late payment charges, which resulted in a reduction to External Revenue of approximately $2.2 million annually. Finally, Hydro One made other updates resulting in further reductions to external revenue. The overall reduction in the 2018 test year as a result of these changes was $6.6 million.

Hydro One submitted that its proposed external revenue and specific service charges, which are largely based on the time study, and taking into account the above-noted revisions, are appropriate.

OEB Staff Submission

OEB staff notes that on May 18, 2018, the OEB issued its Decision on Confidentiality and Procedural Order No. 6 in this proceeding. Among other matters, the OEB provided for submissions by Hydro One, Rogers and other parties on how the OEB might move

[275] Argument-in-chief, p. 143.

forward on the matter of pole attachments in this proceeding in light of the issuance of the *Report of the Ontario Energy Board Wireline Pole Attachment Charges* (the pole attachment report)

Further to the above, on July 12, 2018, the OEB issued a Decision on Pole Attachment Matters and Procedural Order No. 8, in which the OEB noted that the pole attachment report is currently the subject of a Divisional Court proceeding initiated by Rogers and other carriers. The OEB stated that its focus in this proceeding is on whether Hydro One's updated evidence with respect to its proposed Joint Use Telecom Charge, is consistent with the methodology established by the OEB in the pole attachment report. In order to ascertain this, the OEB established a process for written interrogatories and submissions on this matter.

As such, OEB staff's submissions on these issues do not include pole attachment charges. OEB staff submits that the methodology used by Hydro One to calculate its specific service charges is appropriate, and the observed time estimates are consistent with what OEB staff believes to be appropriate. Therefore, OEB staff believes that level of the charges proposed by Hydro One appropriately reflect its costs to provide services.

However, as OEB staff discussed with Hydro One during the oral hearing, the proposed increases in some of these charges are significant and Hydro One acknowledged not undertaking any engagement with customers affected by these increases.[276]

> MR. SIDLOFSKY: My question is: For all the charges of this kind where the proposed increases are significant -- and maybe I'll ask you to agree with me that they're significant. Do you consider them to be that?
>
> MR. MERALI: I would consider the increases significant.
>
> MR. SIDLOFSKY: Okay. And given that, has Hydro One undertaken any specific engagement with the affected customers related to those proposed increases in specific

[276] Transcript, Vol. 5, p. 110 L4-L24.

> charges?
>
> MR. MERALI: Not to my knowledge. Most of the examples you've cited do fall within the customer space, except 6A, which is an easement letter which, I believe, our real estate folks could speak more in depth to, but I can speak to the rest.
>
> There was a time study completed to sort of validate what the specific charges and costs were for Hydro One to execute each of these activities, and that activity was done, I guess, in parallel, but separate from our customer engagement process. So to my knowledge, there was no customer-specific engagement with respect to these charges.

OEB submits that Hydro One should engage affected customers in some fashion when they may be facing a large increase in a specific service charge or charges.

OEB staff notes that subsequent to the above discussion with OEB staff, Hydro One announced reductions in some of the proposed larger increases, though not all. In a footnote to an undertaking on updating other revenues, Hydro One stated that it was making the following changes:[277]

> Regulated Joint Use Revenues have been updated to reflect Hydro One no longer introducing some specific service charges (Rate Code 1, 2, 3, 4, 5, 7, 8, 9, 10, 12, 13, 31(a), 31 (b)), maintaining the current OEB-approved rates for disconnections and reconnections at the meter (Rate Code 18, 19, 20, 21), updating Late Payment Charges (Rate Code19 52) and reducing forestry line clearing costs by $0.08 for 10 feet of power space (Rate Code 47, 48).

However, OEB staff submits that customer engagement on these proposed increases should have taken place. OEB staff submits that wherever lower cost options exist, Hydro One should advise customers of those options.

[277] J 11.2 Filed 2018-07-11.

OEB staff notes in this context that Hydro One stated it expects the volume of many specific charges to decline as more customers move to online self-service tools.[278] When asked what Hydro One is doing to promote the use of self-help options, Hydro One responded that "it's my understanding that when customers do call looking for services, they do direct them to the web portal to try to allow them to go and get their own own information. I do believe that there's bill stuffers. I think there's notices as well that they are doing to try to just notify people of the options that are available."[279]

OEB staff is of the view that specific service charges should recover appropriate costs from the customers that make use of the services for which they are established. As stated above, OEB staff has no issue with how Hydro One has calculated the increases. OEB staff submits however that when the increases are large, the affected customers should be made aware of them some time in advance of their proposed implementation date and if the increases are significant, Hydro One should explore with the affected customers ways to phase them in, rather than not implement them at all as Hydro One appears to be proposing, as this means that other customers will be cross-subsidizing them.

OEB staff submits that Hydro One should provide the OEB with the following breakdown of its specific service charges:

1. Existing specific service charges for which Hydro One is not proposing any change and the current charge.
2. Existing specific service charges for which Hydro One was proposing an increase in the application as filed and for which it is now withdrawing the increase request along with the existing charge and the originally proposed increased charge.
3. Existing specific service charges for which Hydro One was proposing an increase in the application and for which the increase request has not been withdrawn with the existing charge and the proposed increased charge.
4. New specific service charges and the proposed amount which Hydro One is no longer proposing as well as new specific service charges that are still proposed for introduction and their amounts.

[278] Exh. E1, Tab 1, Sch. 2, p. 9.
[279] Transcript Vol.10, p. 144.

5. Any other changes in specific service charges not falling into any of the above categories.

OEB staff further submits that for any remaining specific service charges where Hydro One proposed a significant increase in the application and has not withdrawn this request, such charges should also not come into effect

OEB staff notes that the "Regulated Revenues" component of "External Revenues" is forecast for 2018 as $39.3 million in the updated forecast discussed above. In the application,[280] before the updates, this amount was shown as $42.9 million, meaning that it has been reduced by $3.6 million.

OEB staff observes that the reductions described by Hydro One above, which are summarized in the table below, amount to over $3.8 million which is slightly different from the $3.6 million resulting from the differential between the two "Regulated Revenue" amounts discussed in the previous paragraph.

	$millions
Non-introduction of some SSCs	-0.341
Maintain existing meter connection/disconnection charges	-1.3
Fair Hydro Plan impacts on Late Payment Charges	-2.2
Total Reduction	**-3.841**

OEB staff submits that Hydro One should adjust the amount of $1.641 million consisting of the first two items in the table above to effect the removal impact for any remaining new or significantly increasing charges that remain part of Hydro One's proposal.

OEB staff submits that Hydro One's evidence shows that the general customer base is already cross-subsidizing the specific service charges for which large increases had or are still being requested given the magnitude of the increases required. OEB does not believe that it is reasonable for the general customer base to continue to further cross-subsidize these charges as a result of Hydro One's failure to both engage customers affected by these increases/new charges and to come up with phase-in plans where the customer charge impacts were significant, prior to proposing them for recovery. This is

[280] Exh. E1, Tab 1, Sch. 2, p. 2 Updated: 2017-06-07.

the effect of Hydro One's withdrawal of its proposals in this regard. As such, OEB staff submits that Hydro One should not be permitted to recover these amounts from the general customer base as part of the Decision arising from this application.

H: LOAD AND REVENUE FORECAST

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

Background

Load Forecast

Hydro One filed a load forecast on June 7, 2017 using data available in January 2017. Subsequently, Hydro One prepared a partial update of the application in December 2017. In response to an OEB staff interrogatory,[281] Hydro One filed an updated load forecast on February 12, 2018 informed by 2017 actual loads.

Hydro One "uses a number of methods, such as econometric models end-use models, and customer forecast surveys"[282] in the preparation of its forecast. These consist of a monthly econometric model, two annual econometric models, and an end-use model. Econometric factors used include the provincial GDP forecast, population and household forecasts, commercial output forecast, industrial production forecast. Weather normalization is performed using 31 years of historic actual weather data to establish normal weather, and four years of daily load and weather data to establish a statistical relationship between weather and load at each applicable transformer station or delivery point.[283]

The monthly econometric model links monthly energy consumption to the Ontario GDP and residential building permits. The annual econometric models use disposable income per household, relative energy prices, as well as cooling and heating degree days. In performing the annual econometric forecast, retail and embedded sub-transmission customers are forecasted separately. All econometric models use a statistical regression

[281] Exh. I-46-Staff-219.

[282] Exh E1, Tab 2, Sch. 1, p.1 Updated 2017-06-07.

[283] Exh E1, Tab 2, Sch. 1, pp. 11-13 Updated 2017-06-07.

approach. End-Use models cover each energy use, residential, commercial, industrial, and agricultural.

Historical CDM is added back to the actual load prior to application of econometric and end-use modelling approaches. Subsequent to the modelling, historic CDM, and projected CDM are subtracted from the econometric and end-use models to produce the final forecast. [284]

Hydro One Distribution Load and Number of Customers[285] are shown in the following table:

Year	GWh Delivery Forecast	Distribution Customer Count
2018	36,019	1,300,516
2019	35,680	1,309,216
2020	35,673	1,317,967
2021*	36,363	1,386,522
2022*	36,373	1,395,578

* The figures for 2021 and 2022 include the impact of integrating the Acquired Utilities into Hydro One Distribution.

Hydro One stated that its load forecasting methodology has been found appropriate by the OEB in Hydro One proceedings since 2005 and has proven to accurately forecast load in the past. Hydro One noted that similar methods are used by major utilities throughout North America and its methodology includes the latest Conservation Demand Management (CDM) figures available from the IESO, as well as the latest consensus forecast inputs to the load forecasting models.[286]

OEB staff notes that in Hydro One's 2015 Custom IR application[287], the C(4) coefficient for the LCDD (Logarithm of Cooling Degree Day) variable in the Annual Econometric Model had the lowest t-stat at 1.938992 across all coefficients used in that load forecast. In the current application, the updated load forecast, the C(5) coefficient for the LHDD (Logarithm of Heating Degree Day) variable in the Embedded LDC model has a t-stat of

[284] Exh E1, Tab 2, Sch. 1, p. 11 Updated 2017-06-07.
[285] Exh E1, Tab 2, Sch 1, p. 5 Updated 2017-06-07.
[286] Argument-in-chief, p. 145.
[287] EB-2013-0416.

0.242965. A value of less than approximately 2.0 and greater than approximately -2.0 indicates a lack of statistical significance of an explanatory variable.

LRAMVA

Hydro One stated that going forward, consistent with OEB directives it will track revenue variances due to differences from the CDM assumed in its load forecast via a lost revenue adjustment mechanism variance account (LRAMVA) for the years 2018 to 2020. Hydro One therefore stated that verified LDC energy saving results will be compared with what has been assumed in the forecast prepared for the current rate submission.

Hydro One submitted that its load forecast methodology and forecast of CDM savings are appropriate.

OEB Staff Submission

OEB staff submits that while the output of the current load forecasting methodology is reasonable, there are areas which could be improved, for example, as noted above the model suggests a lack of certainty that the embedded LDCs are sensitive to heating degree days (HDD), which are included as a variable in the model.

Another concern relates to the use of HDD at Pearson Airport. When asked "Why is HDD at Pearson Airport considered to be a suitable explanatory variable for weather impacts for Hydro One's expansive service territory?", Hydro One responded that "weather conditions in different locations across Ontario are similar subject to a few hours difference in timing and, normally, a constant differential in temperature / degree days. Consequently, the Pearson Airport can stand for a close proxy of weather conditions across Ontario."[288] OEB staff submits that a more appropriate option would have been for Hydro One to subdivide the service area geographically, and perform a regression for each area using data from a more locally appropriate weather station. If this proved technically infeasible, at a minimum, it could have attempted to include weather data from multiple disperse stations in a single regression, and reported on the results.

OEB staff submits that while Hydro One has continued to use a proven methodology, it has done so without sufficient consideration of the continued applicability of the inputs and explanatory variables.

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[288] Exh. I-46-Staff-224 f).

While OEB staff believes that Hydro One should address matters such as the above in future load forecast filings, OEB staff does not believe that these matters are of a sufficient level of concern to prevent the filed results from providing a reasonable forecast of load.

OEB staff submits that Hydro One's forecast of CDM savings is appropriate.

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

Background

Hydro One stated that its customer and load forecasts are a reasonable reflection of the energy and demand requirements for the 2018 to 2022 period. Hydro One noted that the load forecast for which it is seeking approval uses the 2017 actual weather-normal load as a starting point and includes the latest economic information for 2018 to 2022. Hydro One also stated that it proposes to provide an updated customer and load forecast for 2021 and 2022 in its application for 2021 rates.[289]

OEB Staff Submission

As noted above, OEB staff submits that the five year forecast of customers and load is reasonable. The proposed update to the load forecast in 2021 is discussed under Issue 14.

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

Background

Hydro One stated that the load forecast has appropriately accounted for the addition of the acquired customers in 2021, as its customer and load forecast for the acquired utilities has been prepared using the same methodology, models and economic assumptions used to prepare the forecast for all of Hydro One's other customers.

Hydro One stated that for the years 2021 and 2022 the embedded load of Norfolk and Haldimand customers is removed from the Sub Transmission (ST) rate class and their

[289] Argument-in-chief, p.146.

residential and general service forecasts are shown in the corresponding acquired rate classes.

Hydro One goes on to explain that Woodstock acquired rate classes will be handled similarly except that its “large user class forecast is combined with the Hydro One ST rate class”. Further, “For all the Acquired Utilities, the forecasts related to Street Light, Sentinel Light and USL classes are combined with the corresponding Hydro One Rate classes.”[290]

OEB Staff Submission

OEB staff submits that the load forecast has appropriately accounted for the addition of the Acquired Utilities’ customers in 2021. OEB staff has made its submissions concerning the proposed 2021 update of the load forecast under Issue 14.

I: COST ALLOCATION AND RATE DESIGN

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

Background

Hydro One stated that it uses the OEB’s cost allocation model (CAM) which follows certain principles to ensure that costs are allocated to the rate classes causing them. Hydro One noted that its CAM continues to use modifications, previously approved by the OEB, necessary to accommodate Hydro One’s specific circumstances related to the treatment of bulk distribution system assets and the use of certain density-based rate classes.

Hydro One further stated that the 2018 and 2021 CAMs have been updated to reflect the proposed revenue requirement and rate base, as well as the charge determinants and rate class load profiles for these years. The 2021 cost allocation models are modified with the inclusion of six new rate classes for the acquired utilities, three for Norfolk and Haldimand, and three for Woodstock. Each group of three new rate classes includes classes for residential, general service energy metered, and general service demand metered.[291]

[290] Argument-in-chief, p. 146.
[291] Argument-in-chief, p. 147.

Hydro One has provided updated load profiles which reflect hourly metered data results from existing Hydro One customers and acquired customers.[292] In doing so, Hydro One has used 2015 actual hourly smart meter data and interval meter data, and scaled the meter data for rate classes where smart/interval meter data was not available for all customers.[293]

OEB Staff Submission

OEB staff submits that Hydro One's inputs to the cost allocation model are appropriate and the costs are appropriately allocated, subject to one concern.

OEB staff notes that in preparing the cost allocation models for 2018 and 2021, Hydro One has applied the street light adjustment factor (SLAF) for primary distribution to both the primary connection count and the total number of customers. In addition, Hydro One applied the SLAF for line transformers to both line transformers and secondary connections. In its report[294], Navigant recommended, and in its letter,[295] the OEB adopted no changes to the existing connection count for secondary distribution.

In response to an OEB staff interrogatory, Hydro One stated that "its SLAF value of 8.48 is not significantly different than the derived value of 8 streetlights per connection", and as a result "does not result in any material change in the revenue-to-cost ratios for any of the rate classes". It went on to commit that "Hydro One will correct this error in the draft rate order phase of this application".[296]

OEB staff agrees with Hydro One that the inadvertent use of a SLAF value of 8.48 vs a daisy chain ratio of 8:1 for customer count and secondary connection count would not impact the results of the cost allocation so materially as to impact the review or consideration of the revenue-to-cost ratios, or any other result of cost allocation. However, OEB staff submits that Hydro One should correct its implementation of the SLAF as part of the preparation of the draft rate order incorporating the OEB's Decision

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[292] Exh G1, Tab 3, Sch. 1, p. 3 Updated 2017-06-07.
[293] Exh E1, Tab 2, Sch. 1, p. 17 Updated: 2017-06-07.
[294] Cost Allocation to Different Types of Street Lighting Configurations, EB-2012-0383, June 12, 2015.
[295] Letter to All Rate-Regulated Electricity Distributors Regarding Review of Cost Allocation Policy for Unmetered Loads EB-2012-0383, Issuance of New Cost Allocation Policy for Street Lighting Rate Class, June 12, 2015.
[296] Exh I 49-Staff-237 a).

and Order in this proceeding, to be consistent with the Navigant recommendations adopted by the OEB.

50. Are the proposed billing determinants appropriate?

Background

Hydro One stated that its proposed billing determinants reflect its proposed customer and load forecast and that it is not proposing any changes to the type of billing determinants currently approved for its existing Hydro One rate classes.

Hydro One proposed to continue to implement the OEB's residential rate design policy, which will result in the elimination of the variable energy charge for existing and acquired residential customers. Also, it "proposes that customers from the Acquired Utilities currently in the Street Light and Sentinel Light classes will adopt the Hydro One billing determinants for those classes starting in 2021."[297]

OEB Staff Submission

OEB staff submits that the proposed billing determinants are appropriate.

51. Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Background

Hydro One stated that it proposes to adjust class revenue recovery as necessary to move the revenue to cost ratios (R/C) for all rate classes to within OEB-approved ranges. In 2018, the Distributed Generation (DG) class is the only rate class where the R/C fell outside the prescribed range in cost allocation. Hydro One proposes to increase the R/C from 0.57 to 0.63 for this class. This is offset by making corresponding decreases to the two rate classes with the highest R/C; the unmetered scattered load rate class, reducing its revenue to cost ratio from 1.15 to 1.09 and the seasonal rate class, which remains at 1.09 before and after the reduction.[298] A further adjustment is proposed to be made to the DG class R/C in 2019, with offsetting decreases to unmetered scattered load, seasonal, and R1 rate classes. In 2020, all rate classes are in the prescribed ranges.

[297] Argument in Chief, page 148.
[298] Exh H1, Tab 1, Sch, 1, p. 9 Updated 2017-06-07.

In 2021, the Acquired Utilities have been included in Hydro One's cost allocation for the first time. All except for the urban residential rate class fell below the prescribed revenue to cost ratios. The proposed changes to the acquired rate classes, and affected legacy rate classes are summarized below:[299]

	Revenue to Cost		Revenue Requirement		
	Cost Allocation	After Rate Design	Cost Allocation	After Rate Design	Revenue to Cost Range
R1	1.10	1.10	361.1	360.3	85-115
Seasonal	1.10	1.10	123.4	122.9	85-115
AUR	0.93	0.93	5.9	5.9	85-115
AUGe	0.73	0.80	1.1	1.2	80-120
AUGd	0.63	0.80	1.4	1.8	80-120
AR	0.84	0.85	17.6	17.8	85-115
AGSe	0.81	0.81	4.0	4.0	80-120
AGSd	0.68	0.80	3.5	4.1	80-120

Since all rate classes are in the target ranges in 2021, no further adjustment is required in 2022.

OEB Staff Submission

OEB staff submits that the R/C ratio adjustments as proposed by Hydro One are appropriate.

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?**

Background

Hydro One submitted that its proposed fixed and variable charges for all of its rate classes are appropriate. It noted that it is moving to fully fixed rates for all its residential

[299] Exh Q1, Tab 1, Sch. 1, Att. 4, p. 4 Filed 2017-12-21.

rate classes in accordance with existing OEB policy, and for other classes, it is maintaining the approach to fixed and variable splits previously approved by the OEB. Hydro One stated that in the case of customers moving to the new acquired general service rate classes in 2021, it will either adopt the fixed-to-variable split previously approved by the OEB for the Acquired Utilities, or it will apply a blended value of the OEB approved splits.[300]

Through an interrogatory,[301] OEB staff requested an explanation of the methodology used for implementing the residential rate design policy, and derivation of the fixed charges for the residential rate classes for each of the years in the Custom IR period.

In its response, Hydro One explained that the approach used in the revenue requirement work form (RRWF), Tab 12, is a two-step process. First, the fixed and variable rates are increased by the same percentage to recover the full revenue requirement for the test year, then the fixed charge is increased and the variable charge decreased, to implement the transition towards a fully fixed residential rate. Hydro One's alternative method determines the fixed charge that would be required to fully recover the revenue requirement in the test year, and moves a proportionate step from the existing fixed charge to the full recovery fixed charge in a single step. Hydro One reasons that this method "results in a smoother transition to all-fixed rates" and "helps mitigate the impact on low volume customers during rebasing".[302] As an example, Hydro One calculated that in the 2018 test year, the fixed charge for the R1 rate class increased $4.02 using their approach, but increased $5.52 using the approach in the RRWF.

Hydro One provided the year-over-year fixed charge increases in response to an interrogatory.[303] The combined impact of revenue requirement and residential rate design impact is summarized below.

[300] Argument-in-chief, pp. 148-149.
[301] Exh. I-49-Staff-245.
[302] Exh. I-49-Staff-245 a).
[303] Exh. I-49-Staff-245-01.

		2018	2019	2020	2021	2022
UR	RRWF	$28.60 -$24.78 =$3.82	$32.21 -$28.60 =$3.61	$35.85 -$32.21 =$3.64	-	-
	Proposed	$27.71 -$24.78 =$3.93	$31.23 -$27.71 =$3.52	$35.85 -$31.23 =$4.62		
R1	RRWF	$39.29 -$33.77 =$5.52	$44.53 -$39.29 =$4.24	$49.89 -$44.53 =$5.63	$54.87 -$49.89 =$4.98	$60.14 -$54.87 =$5.27
	Proposed	$37.79 -$33.77 =$4.02	$42.19 -$37.79 =$4.40	$47.06 -$42.19 =$4.87	$52.31 -$47.06 =$5.25	$58.26 -$52.31 =$5.95
R2	RRWF	$92.20 -$80.33 =$11.87	$103.23 -$92.20 =$11.03	$114.24 -$103.23 =$11.01	$125.24 -$114.24 =$11.00	$136.49 -$125.24 =$11.25
	Proposed	$88.61 -$80.33 =$8.28	$97.68 -$88.61 =$9.07	$107.71 -$97.68 =$10.03	$118.85 -$107.71 =$11.14	$131.71 -$118.85 =$12.86
Seasonal	RRWF	$42.09 -$36.28 =$5.81	$47.40 -$42.09 =$5.31	$51.36 -$47.40 =$3.96	$55.33 -$51.36 =$3.97	63.49 -$55.33 =$8.16
	Proposed	$40.52 -$36.28 =$4.24	$45.07 -$40.52 =$4.45	$50.05 -$45.07 =$4.98	$55.37 -$50.05 =$5.32	$61.48 -$55.37 =$6.11

OEB staff notes that given the methodology proposed by Hydro One, it is not possible to isolate the amount of increase proposed due to the residential rate design policy alone. However, the current implementation schedule was selected by the OEB to strike a balance between keeping increases to $4/year, and implementing the residential rate design in a reasonable time period.[304]

OEB staff observes that using the method in the RRWF, the total fixed charge increase, including the increase in revenue requirement and rate design, in the R1 rate class varies from a low of $4.24 in 2019 to a high of $5.63 in 2020, and Hydro One's approach results

[304] EB-2015-0079, Decision and Order, December 22, 2015, p. 7.

in total fixed charge increases that range from a low of $4.02 in 2018 to a high of $5.95 in 2022. Similarly, for the R2 class, using the method in the RRWF, the total fixed charge increase varies from a low of $11.00 in 2021 to a high of $11.87 in 2018, and Hydro One's approach results in total fixed charge increases that range from a low of $8.28 in 2018 to a high of $12.86 in 2022.

OEB Staff Submission

OEB staff submits that Hydro One's approach to rate design results in year over year fixed charge increases that have been larger in each subsequent year for the R1, R2, and Seasonal rate classes. Further, these rate increases reach larger absolute amounts of $5.95 for R1 and $12.86 for R2, than the methodology embedded in the RRWF. Finally, since the proposed fixed charges in 2022 are less than those which would result from using the methodology in the RRWF, the proposed methodology is setting up larger increases in 2023, the final year of the transition.

OEB staff submits that if Hydro One's objective is a "smoother transition to all-fixed rates", this is better achieved with the method included in the RRWF, and typically used by electricity distributors. Therefore, OEB staff submits that Hydro One should adopt the method in the RRWF for implementing the transition to fixed residential rates in accordance with the residential rate design policy.

53. **Are the proposed Retail Transmission Service Rates appropriate?**

Background

Hydro One proposed to use Retail Transmission Service Rates that reflect the latest approved Uniform Transmission Rates and uses the latest rate class share of transmission charges per the methodology approved by the OEB in Hydro One's prior application.[305]

OEB Staff Submission

OEB staff submits that the Retail Transmission Service Rates are appropriate.

[305] Argument-in-chief, p. 149.

54. **Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?**

OEB staff's submissions for this issue are included under Issue 45.

55. **Are the proposed line losses over the 2018 – 2022 period appropriate?**

Background

Hydro One stated that it proposes to continue to use the total loss factors approved by the OEB in the previous distribution rates proceeding for all existing Hydro One rate classes for the 2018 to 2022 Custom IR period as these remain consistent with the five-year average historical losses.

For the acquired rate classes, Hydro One proposed to use the Acquired Utilities' currently approved loss factors as a starting point, while taking into account that customers of the acquired utilities now share in the use of Hydro One's bulk (sub-transmission) assets.[306]

OEB Staff Submission

OEB staff submits that the proposed line losses are appropriate.

56. **Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?**

Background

Hydro One noted that the OEB's direction, in its decisions on Hydro One's applications to acquire Norfolk Hydro, Haldimand Hydro and Woodstock Hydro, was that the customers of these utilities be charged rates that reflect the cost to serve them. Hydro One further noted that its total revenue requirement in 2021 includes $25.6 million in incremental revenue requirement associated with serving the Acquired Utilities' customers, which was less than the expected $39.9 million in revenue that would need to have been collected from Acquired Utilities' customers had they not been acquired by Hydro One.[307]

[306] Argument-in-chief, pp. 149-150.
[307] Argument-in-chief, p. 150.

Hydro One is proposing to use the CAM to allocate costs to across all rate classes, including the Acquired Utilities' rate classes in 2021. In order to do this it has proposed allocating the forecasted 2021 capital assets related to the Acquired Utilities using adjustment factors. Hydro One stated in its application that two adjustment factors were developed and included in the 2021 CAM to ensure that the capital costs allocated to the six new acquired rate classes appropriately reflect the cost of serving the customers in these rate classes.[308] The new adjustment factors were created for gross fixed assets and net fixed assets. In both cases, the adjustment factors were created to align the costs allocated by the cost allocation model with the costs required to serve the acquired rate classes. In addition, depreciation was adjusted by the gross fixed asset adjustment factor, reflecting the reduction in gross fixed assets used to serve the acquired rate classes.[309]

OEB Staff Submission

OEB staff submits that the adjustment factors are, in effect, performing a direct allocation of assets and depreciation to the Acquired Utilities. OEB staff accepts that where costs associated with specific rate classes are known, direct allocation is appropriate. OEB staff submits that Hydro One's proposal to use the adjustment factors for capital and the allocation of OM&A costs based on the CAM is a reasonable proxy for reflecting the cost to serve.

OEB staff also submits that based on Hydro One's calculation of the expected revenue of $39.9 million that would have been collected from the Acquired Utilities if they had not been acquired by Hydro One and the total proposed revenue to be collected from the Acquired Utilities' six rate classes of $34.9 million[310], the Acquired Utilities are paying marginally less than they would have otherwise.

[308] Exh G1, Tab 3, Sch. 1, p. 5 Updated: 2017-06-07.
[309] Exh G1, Tab 3, Sch. 1, p. 5 Updated: 2017-06-07.
[310] Transcript Vol. 10, p.168.

J: DEFERRAL/VARIANCE ACCOUNTS

57. Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Background

Hydro One stated that the regulatory accounts for which it is seeking continuance and disposition, disposition only or continuance only are as below:[311]

Description	US of A Account Ref.	Balance as at Dec. 31, 2013	Balance as at Dec. 31, 2014	Balance as at Dec. 31, 2015	Balance as at Dec. 31, 2016	Forecast Balance as at Dec. 31, 2017
Regulatory Accounts Seeking Continuance and Disposition						
Retail Settlement Variance Accounts *(excluding Global Adjustment)*	1550 to 1588	(13.1)	(2.1)	49.5	30.4	30.7
Retail Cost Variance Accounts	1518/1548	1.0	0.7	0.0	0.7	0.7
Pension Cost Differential Account	1508	59.3	78.9	23.0	7.9	7.9
Tax Rate Changes Account	1592	(17.5)	(21.9)	(4.3)	(4.4)	(4.4)
OEB Cost Differential Account	1508	0.0	0.0	0.0	(1.3)	(1.3)
Smart Meter Entity Charge Variance Account	1551	0.7	0.5	0.3	(0.1)	(0.1)
Regulatory Accounts Seeking Disposition Only						
Revenue Offset Difference Account – Pole Attachment Charge	2405	0.0	0.0	0.0	(2.2)	(2.3)
Bill Impact Mitigation Variance Account	1508	0.0	0.0	1.8	2.3	2.4
Microfit Connection Charge Variance Account	1508	(1.6)	(2.4)	(0.8)	(0.8)	(0.8)
Distribution Generation – Other Costs – HONI - Variance Account	1533	(1.2)	(0.6)	0.6	0.6	0.6
Distribution Generation– Express Feeders - HONI - Variance Account	1533	(0.3)	(0.3)	(0.0)	(0.0)	(0.0)
Smart Grid Variance Account	1536	(1.1)	(12.8)	(11.9)	(12.1)	(12.2)
Distribution System Code (DSC) Exemption Deferral Account	1508	6.6	16.0	9.5	9.6	9.7
Total Regulatory Accounts for Disposition		**32.9**	**56.0**	**67.8**	**30.6**	**30.9**
Regulatory Accounts Not Seeking Disposition						
RRRP	1508	2.3	1.2	(1.8)	0.0	0.0
Distribution Generation – Other Costs – Provincial - Variance Account	1533	(48.1)	(64.0)	(60.5)	(52.7)	(53.3)
Distribution Generation – Express Feeders – Provincial – Variance Account	1533	(3.6)	(4.8)	(4.9)	(5.0)	(5.0)
Rider 2015 to 2017 – Disposition and Recovery of Regulatory Balances (OEB Approved)	1595	0.0	0.0	20.4	6.7	0.4
Revenue Difference Account – Pole Attachment Charge	1508	0.0	0.0	0.0	1.0	1.0
Long Term Load Transfer Rate Impact Mitigation Deferral Account	1508	0.0	0.0	0.0	0.0	0.0
Smart Grid Fund (SGF) Pilot Deferral Account	1508	0.0	0.0	0.0	0.0	0.0
Retail Settlement Variance Account – Power – Sub-Account – Global Adjustment	1589	(22.4)	9.2	62.2	116.6	117.9
Others		(7.8)	21.6	0.0	0.0	0.0
Total Regulatory Accounts Not Seeking Disposition		**(79.7)**	**(36.8)**	**15.4**	**66.7**	**61.1**
Total Regulatory Accounts		**(46.8)***	**19.2**	**83.2**	**97.2**	**92.0**

[311] Exh. F1, Tab 1, Sch. 1, p. 3 Updated: 2017-06-07.

Hydro One further stated that all of the regulatory accounts reported by it have been established consistent with the OEB's requirements as set out in the Accounting Procedures Handbook, OEB directions, or pursuant to specific requests initiated by Hydro One. Hydro One noted that accounting orders were provided for new accounts and in answer to interrogatories for existing accounts.[312]

Hydro One stated that, as noted at the oral hearing, the OEB had issued a letter to it indicating that it would be undertaking an audit of Hydro One's Regulated Price Plan (RPP) settlement process and to assess the allocation methodology Hydro One uses to assign balances for Group 1 deferral and variance accounts for all acquired utilities from 2015 onwards. Hydro One stated that the results of this audit could potentially impact the 2015 and 2016 Group 1 account balances originally proposed for disposition. As a result, Hydro One is proposing to clear principal balances of Group 1 accounts as of December 31, 2014 and Group 2 balances as of December 31, 2016 with interest calculated to December 31, 2017. Hydro One noted that this proposal would result in a total debit balance of $8.3 million to be disposed as shown in the table below.[313]

Account Name	Account Number	Total Claim $Million (Interest and Principal)
Group 1 (Principal as of Dec 31, 2014)		
Smart Meter Entity Charge Variance Account	1551	0.5
LV Variance Account	1550	6.1
RSVA - Wholesale Market Service Charge	1580	(91.6)
RSVA - Retail Transmission Network Charge	1584	44.5
RSVA - Retail Transmission Connection Charge	1586	30.6
RSVA - Power - Sub-Account -Power	1588	8.3
RSVA - Power - Sub-Account -Global adjustment	1589	9.6
Total Group 1		**8.0**
Group 2 (Principal as of Dec 31, 2016)		
RCVA	1518/1548	0.7
Pension Cost Differential Account	1508	7.9
Tax Rate Changes Account	1592	(4.4)
OEB Cost Differential Account	1508	(1.3)
Revenue Offset Difference Account - Pole Attachment Charge	2405	(2.3)
Bill Impact Mitigation Variance Account	1508	2.4
Microfit Connection Charge Variance Account	1508	(0.8)
DG - Other Costs - HONI - Variance Account	1533	0.6
DG - Express Feeders - HONI - Variance Account	1533	0.0
Smart Grid Variance Account	1536	(12.2)
DSC Exemption Deferral Account	1508	9.7
Total Group 2		**0.3**
Total Group 1 and Group 2		**8.3**

[312] Argument-in-chief, p. 152

[313] Argument-in-chief, p. 153.

Hydro One proposed that given the total balance being sought for disposition is significantly reduced from the original filing, it should be recovered over a one year time period.[314]

OEB Staff Submission

As noted in the July 20, 2018 letter from the OEB to all rate-regulated licensed electricity distributors[315], the OEB will not be approving Group 1 rate riders on a final basis pending the development of further accounting guidance to commence the standardization of accounting procedures relating to RPP wholesale settlements. Therefore any adjustments made subsequent to the disposition of Group 1 account balances can be addressed as part of the Hydro One's next Group 1 account disposition.

OEB staff submits that in light of the pending OEB audit of Hydro One's RPP settlement process, there is greater potential for material adjustments to the balances of the 2015 and 2016 Group 1 Deferral and Variance accounts. Therefore, OEB staff has no concerns with Hydro One's decision to only seek disposition of the Group 1 account balances as of December 31, 2014. However, pursuant to the July 20th direction from the OEB, this disposition should not be on a final basis.

OEB staff notes that in its pre-filed evidence for account 1589, RSVA – Power, sub-account- Global Adjustment, Hydro One confirmed that it had received a refund from the IESO between April and November 2017, totaling $121.8 million. The refund was received due to a clarification of embedded generation submissions used in the calculation of the Global Adjustment applicable to Hydro One Distribution from January 2005 through to August 2016. In its original application, Hydro One had proposed to offset this credit from the IESO against its December 31, 2016 balance in account 1589 of $116.6 million[316]. As a result, Hydro One was not seeking disposition of the December 31, 2016 balance in account 1589 on the basis that the balance would be recovered through the IESO credit.

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[314] Argument-in-chief, p.152.

[315] OEB letter to all rate-regulated licensed electricity distributors, dated July 20, 2018, Re. OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts.

[316] Exh. F1, Tab 1, Sch. 1, p.5.

As noted, Hydro One is now only seeking disposition of its Group 1 account balances up to December 31, 2014 as a result of the pending OEB audit. Included in the balances now being sought for disposition is a debit balance of $9.6 million in account 1589. OEB staff submits that Hydro One has not applied any of the IESO credit against the December 31, 2014 balance in account 1589, as it had previously proposed. The credit from the IESO covers the period January 2005 to August 2016 and therefore it would appear that a large portion of that credit would relate to the period of 2014 and prior. OEB staff submits that Hydro One should prorate the IESO credit and apply only the portion of that credit relating to 2014 and prior to the balance in Account 1589 at December 31, 2014. It would be unreasonable to ask the ratepayers to wait until Hydro One's next Group 1 account disposition to receive these amounts, especially given that Hydro One has already collected the full balance from the IESO.

OEB staff makes the following additional observations regarding the IESO credit discussed above. This is a significant correction that raises concerns as to Hydro One's ability to settle accurately with the IESO. OEB staff anticipates that the drivers for the discrepancies that led to the credit will be addressed as part of the ongoing audit of the RPP settlement process.

With respect to the appropriateness of disposing of the credit to ratepayers, OEB staff notes the following. The settlement transactions giving rise to the credit took place in calendar year 2017. Hydro One has yet to dispose of the 2017 account balances. Accordingly, OEB staff does not consider the credit to be out of period. However, given that the original settlement activities took place in prior periods with final rates, it might be argued that the disposition of the credit balance amounts is retroactive ratemaking. OEB staff submits that even if retroactive ratemaking were to be a consideration, the credit balance should still be returned to ratepayers. The OEB has in the past taken an asymmetrical approach to correcting prior period errors, and in cases where the adjustments favour ratepayers, the OEB has directed distributors to make those adjustments.[317]

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[317] In EB-2014-0114, the OEB approved the correction of a misallocation of Global Adjustments between RPP and non-RPP in settlements with the IESO due to exclusion of embedded generation in settlement forms. In that Decision, the OEB stated "…an out-of-period adjustment can be justified if it ensures a utility does not profit on account of its own errors. Should the monies not be returned to Thunder Bay Hydro's customers, it is Thunder Bay Hydro that would benefit from the error. This would be untenable."

58. **Are the proposed new deferral and variance accounts appropriate?**

Background

Hydro One stated that it is seeking approval to continue or establish the following regulatory accounts:

- Pension Cost Differential Account
- Tax Rate Changes Account
- Smart Meter Entity (SME) Charge Variance Account
- LRAMVA
- Capital In-Service Variance Account (CISVA)
- ESM Deferral Account
- Bill Impact Mitigation Variance Account
- Other Post-employment Benefit (OPEB) Cost Deferral Account
- Long Term Load Transfer Rate Impact Mitigation Deferral Account

OEB Staff Submission

OEB staff submits that it has no concerns with the accounts listed above except for the proposed new OPEB Cost Deferral Account. The remainder of this section focuses on OEB staff's submission related to that proposed account.

OPEB Cost Deferral Account

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) No. 2017-07 that amends the US GAAP accounting standard for pension and other post-employment benefit (OPEB) costs effective January 1, 2018. The amendments allow only the service cost component of the net periodic pension cost and the net periodic OPEB cost to be eligible for capitalization.

Under current US GAAP, the net periodic benefit cost from defined benefit pension and OPEB plans is comprised of several components, including current service cost, interest cost, return on plan assets and the amortization of actuarial gains/losses and prior service costs. Prior to the issuance of ASU No. 2017-07, an entity following US GAAP was eligible to capitalize all components of net periodic benefit cost provided that the costs met the specific capitalization criteria under US GAAP. However, ASU No. 2017-07 now only permits the capitalization of the service cost component of net periodic benefit cost.

For rate setting purposes, Hydro One has indicated that the new ASU does not impact the regulatory accounting for its pension costs because the cash method is used to account for these costs. However, since its OPEB costs are accounted for using the accrual method, the new ASU impacts the level of capitalization that is permitted for these costs.[318]

In its application, Hydro One had initially requested approval for the establishment of a deferral account to capture all the elements of the net periodic benefit costs other than service cost that would have been classified as capital prior to the issuance of ASU No. 2017-07[319]. However, during the oral hearing, Hydro One further clarified its intention with respect to the requested variance account:

> MR. CHHELAVDA: Ideally we would like to continue to capitalize those costs; that would be our first preference. Failing that, the second option would be the deferral account.

The option to continue to capitalize arose from discussions Hydro One had with its auditors in which they advised that it could continue capitalizing OPEB costs without the requirement of a deferral account if approved to do so by its respective regulator. The US Federal Energy Regulatory Commission (FERC) provided such approval to utilities under its jurisdiction. Once the regulator grants such approval for the continued capitalization of the impacted costs, then this accounting treatment becomes acceptable under US GAAP.[320]

With respect to its OPEB costs, Hydro One is seeking to recover the following amounts for its distribution business in the test period.[321]

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[318] Exh. C1, Tab 2, Sch 2.
[319] *Ibid*.
[320] Transcript Vol. 4, p. 52.
[321] Exh. I, Tab 40, Sch. Staff-215.

2018 Forecast OPEB Costs

	Transmission	Distribution	Other	Total
OM&A	17	26	4	47
Capital	32	25	0	57
	49	**51**	**4**	**104**

The figures in the table above do not reflect the changes required under ASU No. 2017-07. It is estimated that approximately $13 million[322] of the distribution related OPEB costs currently presented as capital above are not eligible to be capitalized under the new ASU. Therefore those amounts may need to be adjusted depending on the OEB's decision on this matter.

Deferral Account Option

In the application as filed, Hydro One had initially come to the OEB with the intention to request a deferral account that would capture the impact of ASU No. 2017-07. The draft Accounting Order states that this account will function as follows[323]:

> Changes to US GAAP effective January 1, 2018 allow only the service cost component of the net periodic post-retirement benefit cost to be eligible for capitalization when applicable. The re-classification of these elements to OM&A would have an adverse impact on rates in a given year. Therefore Hydro One Distribution proposes the establishment of a new "Other Post-employment Benefit (OPEB) Cost Deferral Account" to record all elements of the net periodic benefit cost other than the service cost that would have been classified as capital prior to the issuance of the new accounting rules.

In response to OEB staff interrogatories, Hydro One further clarified the intended functionality of the deferral account by stating the following[324]:

As indicated in Exhibit C1, Tab 2, Schedule 2, section 5.1, the reclassification of these elements to OM&A would have an adverse impact on rates in a given year. For this reason, Hydro One proposes to capture the impact in a deferral account as noted in

322 Exh. I, Tab 40, Sch. Staff 217.
323 Exh. I, Tab 57, Sch. Staff 273.
324 , Exh. I, Tab 40, Sch. Staff 217.

Exhibit F1, Tab 3, Schedule 1 of the application. In order to minimize the impact on rates, it is Hydro One's intention to clear the deferral account over a period that is consistent with the useful lives of the assets to which such costs would have previously been capitalized, but not to exceed 20 years.

OEB staff submits that the use of a deferral account in the manner outlined above – that is, mainly to mitigate the adverse impact that this accounting standard change has on rates – is not required. The estimated $13 million impact in the 2018 test period represents less than 1% of the forecast 2018 revenue requirement and therefore its overall impact on rates is not significant enough to warrant a mitigation strategy. If OEB staff's position is accepted, then Hydro One would need to reclassify the estimated $13 million of impacted costs currently recorded as capital to OM&A in the 2018 test period. Hydro One would also need to further consider the corresponding impacts to the return on equity, depreciation, and PILs and adjust each accordingly.

OEB staff notes that Hydro One had made a similar request for a deferral account for their transmission business[325]. In that proceeding, the OEB approved a deferral account until such time as the effective date of Hydro One's next transmission revenue requirement. Hydro One's 2018 transmission revenue requirement was approved based on the previous US GAAP standard on pension and OPEB costs. Therefore the approved deferral account is an interim measure to capture the impact of the new accounting standard on 2018 so that the OEB can consider in Hydro One's next transmission revenue requirement proceeding whether Hydro One should continue to capitalize OPEBs despite the new US GAAP accounting standard. With the establishment of that deferral account, the OEB did not need to make that determination at that time and kept all regulatory options open.

Request to Continue to Capitalize the Impacted Costs

As outlined above, Hydro One has also proposed an alternative to the use of a deferral account. It has proposed the continued capitalization of the impacted costs, which in turn would also enable it to continue to capitalize these costs under US GAAP. Hydro One has noted that FERC has also provided similar approval to utilities under its jurisdiction.[326]

[325] EB-2017-0338.
[326] EB-2017-0049, JT 1.16.

OEB staff submits that the OEB should not grant Hydro One the approval to continue to capitalize the impacted costs. Hydro One's capitalization policies already appear to be far more aggressive than other US GAAP regulated utilities in Ontario. The OEB regulates several other utilities that follow US GAAP for regulatory reporting purposes, such as Ontario Power Generation, Union Gas and Enbridge Gas Distribution. To date, no other US GAAP utility has approached the OEB to request similar relief related to the change in this accounting standard.

Furthermore, in response to OEB staff interrogatory 215, the Hydro One provided a breakdown between capital and OM&A with respect to its test period OPEB costs. That analysis illustrated that Hydro One has proposed to capitalize approximately 50% of its forecast test period OPEB costs. In contrast, as part of the recent Union/Enbridge amalgamation proceeding[327], OEB staff asked an interrogatory about the impact that ASU No. 2017-07 could have on the revenue requirement of the amalgamated utility. In the response provided by the applicants, they indicated that the new ASU is not expected to have a significant impact since Enbridge Gas does not currently capitalize pension and OPEB related costs, while Union Gas estimated its impact to be less than $1 million[328]. During the oral hearing, Hydro One explained that such a discrepancy can be explained by factors such as the level with which a utility outsources its capital projects compared to performing that work in-house[329]. While such an explanation does have merit, OEB staff submits that the degree of the gap in capitalization illustrated in the above example would suggest that Hydro One employs a more aggressive approach to the capitalization rules.

MIFRS Capitalization Policy

OEB staff notes that Hydro One's request for OEB approval to continue to capitalize certain OPEB costs that they are no longer permitted to under US GAAP underscores the greater issue of whether it is still appropriate for utilities that report under US GAAP for regulatory purposes to follow a capitalization policy that differs from the one mandated under MIFRS. By virtue of following US GAAP for regulatory purposes, it enables those utilities to capitalize significantly more overhead costs than otherwise

[327] EB-2017-0307.
[328] EB-2017-0307, Exhibit C, Staff 57.
[329] Transcript Vol. 4, p. 53.

would be permitted had they been reporting under the MIFRS framework. During the oral hearing, Hydro One estimated that over the current application period, they have capitalized approximately $300-320 million more than they otherwise would have had they been following the OEB's capitalization policy under MIFRS (on a total company basis).[330]

In its decision in the last proceeding for Hydro One's transmission revenue requirement[331], the OEB provided findings on Hydro One's capitalization of overheads, stating:

> ...the OEB shares the same concern of those who question the continued appropriateness of the large capitalization amounts that US GAAP allows compared to the amounts allowed under MIFRS regulatory accounting purposes.
>
> Hydro One's use of US GAAP for regulatory purposes in connection with its 2017 and 2018 rates revenue requirements , including the capitalization of overheads, will not be varied at this time. Separate and apart from this proceeding, the OEB will consider whether it should initiate a policy review of the appropriateness of the continued use by the utilities it regulates of US GAAP for the purpose of determining the capitalization of overhead amounts.[332]

OEB staff notes that no policy review has been initiated on this matter to date. That does not however mean that the OEB cannot revisit this matter on a case by case basis. OEB staff submits that there is merit in having utilities that follow US GAAP for regulatory reporting purposes, such as Hydro One, to adopt the OEB's MIFRS capitalization policy to bring them in line with all other regulated utilities in Ontario. .

OEB staff further submits that mandating US GAAP regulated utilities to adopt the OEB's MIFRS capitalization policy would facilitate better benchmarking across regulated utilities in Ontario. In the proceeding that approved Hydro One's use of US GAAP for regulatory

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[330] Transcript Vol. 4, p. 67.
[331] EB-2016-0160.
[332] EB-2016-0160, Decision and Order, p. 82.

purposes, several intervenors and OEB staff were concerned that the transition to US GAAP would not facilitate benchmarking of its results with those of other Ontario distribution utilities. Hydro One responded to those concerns by indicating that it was aware of these benchmarking concerns and submitted that total costs benchmarking will be more of a challenge as time passes due to the inclusion of depreciation expenses in total costs. It stated that it would work toward developing solutions to allow appropriate total cost benchmarking in the short and longer term.[333] In that Decision and Order, the OEB stated that it considered it important that Hydro One develop a definitive methodology which allows its results to be appropriately comparable with the results of other distribution utilities in Ontario[334]. Hydro One may wish to confirm how the concerns raised in that proceeding have been addressed.

That said, as part of its most recent Business Plan, the OEB is now considering alternative ways to remunerate utilities in ways that strengthen their focus on long-term value and least-cost solutions.[335] In OEB staff's view, given this new initiative, it may be prudent not to mandate at this time a transition that will have a short term adverse impact on ratepayers (i.e. by increasing revenue requirement), but rather await the outcome of the new initiative (or alternatively a dedicated policy review on this matter) and revisit this matter at Hydro One's next cost based application due for 2023 rates.

59. Is the proposal to discontinue several deferral and variance accounts appropriate?

Background

Hydro One stated that it is not seeking continuation of the following accounts:

- Rural or Remote Electricity Rate Protection ("RRRP") Variance Account;
- Bill Impact Mitigation Variance Account;
- Revenue Offset Difference Account – Pole Attachment Charge; and
- Revenue Difference Account – Pole Attachment Charge.

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[333] EB-2011-0399, Decision an Order, p. 7.
[334] EB-2011-0399, Decision an Order, p. 9.
[335] OEB 2018-2021 Business Plan, p. 24.

Hydro One stated that it was doing this because, as detailed in the application, there are no future requirements associated with the purposes for which these accounts were originally established. Accordingly, Hydro One submitted that these accounts should be discontinued.

OEB Staff Submission

OEB staff has no concerns with the discontinuance of the above noted accounts, However, in light of the on-going parallel proceeding on the pole attachment charge, OEB staff submits that the Revenue Offset Difference Account – Pole Attachment Charge; and Revenue Difference Account – Pole Attachment Charge may again be required pending the outcome of that parallel proceeding.

-All of which is respectfully submitted-