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Ontario

BY E-MAIL

December 11, 2019

Attention: Ms. Christine Long, Registrar and Board Secretary

Dear Ms. Long:

Re: Hydro One Networks Inc.
Custom IR Application
OEB File Number EB-2019-0082

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

Original Signed By

Martin Davies
Project Advisor, Rates
Electricity Distribution: Major Rate Applications & Consolidations

Ontario Energy Board

Hydro One Networks Inc.

2020 - 2022 ELECTRICITY TRANSMISSION CUSTOM IR APPLICATION

EB-2019-0082

ONTARIO ENERGY BOARD STAFF SUBMISSION

December 11, 2019

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INTRODUCTION

Hydro One Networks Inc. (Hydro One) filed a three-year Custom Incentive Regulation (Custom IR) application with the Ontario Energy Board (OEB) on March 21, 2019 with subsequent updates under section 78 of the *Ontario Energy Board Act, 1998*[1], seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2020 with the proposed Custom Incentive Rate-Setting model for the period effective January 1, 2021 to December 31, 2022 (the application).

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

The application requests approval of a transmission revenue requirement over a three year period using a Custom IR methodology. Hydro One uses a cost of service based revenue requirement for 2020 and then applies an annual adjustment, where the revenue for the 2020 base year is adjusted annually by an index to set the revenue requirements for 2021 and 2022. The index is comprised of an inflation factor, a productivity factor (including a stretch factor) and a custom capital factor.

- The applied-for total revenue requirement of $1,602.3 million, is $42.1 million lower than the OEB 2019 approved levels, not including External & Other Revenue and Regulatory Accounts. When these items are included, the resulting total 2020 rates revenue requirement is $1,556.6 million, or a $4.3 million increase over 2019 OEB-approved levels.

- After an adjustment for a reduced load forecast driven by a government conservation policy change, estimated total bill impact for a typical Hydro One medium density (R1) residential customer (750 kWh/month) is an increase of 0.3% ($0.37/month) in 2020. The estimated total bill impact for a typical Hydro One general service energy less than 50 kW customer (2,000 kWh/month) is an increase of 0.3% ($0.88/month) in 2020.

[1] S.O. 1998, c.15 (Schedule B)

- In response to customer concerns about rising rates, Hydro One indicated that it is sensitive to the rate impact of its plan on both its transmission customers and distribution-connected customers. Hydro One stated that its plan appropriately balances the needs of the system and the customer preferences regarding outcomes and rates.

- Hydro One's proposed Custom IR plan has many elements in common with Hydro One SSM's Revenue Cap IR plan proposal in EB-2018-0218 and Hydro One's Distribution Custom IR plan (EB-2017-0049). Hydro One's proposed Productivity Factor is 0.0%, combined with an electricity transmission sector-specific inflation factor of 1.4% and a Custom Capital Factor designed to ensure that total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in the Transmission System Plan (TSP).

- Hydro One has proposed an earnings/sharing mechanism that will permit customers to share 50% of any earnings exceeding the regulatory ROE by more than 100 basis points in any year of the Custom IR term.

- Hydro One has filed an evolved scorecard reflecting the OEB's feedback from the previous transmission proceeding. The reliability performance measures and descriptions remain unchanged from the previous Hydro One Transmission application.

- Requested OM&A expenses for 2020 of $374.1 million (a 5.1% decline from 2018 plan levels) reflect reductions which will be achieved through operating efficiencies, particularly the management of maintenance cycles, and a company-wide exercise undertaken by Hydro One to review and reduce corporate costs.

- Hydro One's staffing and compensation levels are showing increases over the period of the application with compensation costs increasing by 12% over the test period. FTEs are also showing increases with an 8.5% increase from 2018 to 2020 (from 4,247 to 4,691).

- The application includes a TSP on which, over the application period, Hydro One plans to spend approximately $3.9 billion in capital, which is an increase of 31.1% over 2017-2019 spending of roughly $3 billion to restore transmission reliability performance to top quartile as compared to its Canadian peers, address customer needs and preferences and mitigate asset and operational risks. Hydro One stated that the proposed investments are targeted at the highest risk assets and will eliminate all critical safety and environmental risks.

- Hydro One identified expected productivity savings in Capital and OM&A totaling approximately $704 million over the TSP planning period, approximately $370 million of which is expected during the test period. These savings have been embedded into the cost forecasts underpinning the TSP.

- The key load forecast supporting Hydro One's transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: Network Pool, Line Connection Pool, and Transformation Connection Pool. The load forecast in support of this Application was prepared in December 2018, using the available economic and forecast information.

- Hydro One continues to follow the OEB-approved methodology from the last transmission rebasing application to allocate the transmission rates revenue requirement into three rate pools: Network, Line Connection and Transformation Connection. The rate pools are based on functional categories of assets and their associated costs.

- Hydro One is seeking disposition of its December 31, 2018 deferral and variance account balance of $20.5 million over a three year period commencing in 2020.

OVERVIEW OF OEB STAFF'S SUBMISSION

The following table provides a summary of the main issues addressed in OEB staff's submission with respect to the Application. OEB staff has provided a high-level estimate of the impacts of its proposed changes on the revenue requirement and other items (as appropriate). The estimates with respect to the impact on revenue requirement were made in isolation of each other (and there is expected to be an interaction between many of the proposed changes).

Table 1
Submission Summary

Issues	**Estimated Impact on 2020-2022 Proposals**
Custom IR Framework • Accept proposed use of OEB-approved transmission implicit price index (IPI) for inflation calculation and annually update inflation factor to the most current OEB-approved. 2020 value = 1.8% • Accept base productivity factor of 0%, as is currently approved for Hydro One Sault Ste. Marie, and based on analysis of updated Total Factor Productivity evidence of PSE and PEG • Apply 0.30% stretch factor in Custom IR revenue cap formula • Apply 0.15% incremental stretch factor on capital in C-factor formula • Accept 0% growth factor in the Custom Revenue Cap Index (CRCI) formula • Accept proposed Earnings Sharing Mechanism (ESM) • Accept proposed Z-factor availability in accordance with OEB policy • Accept proposed off-ramp in accordance with OEB policy • Accept proposed annual Custom IR update approach with one exception, discussed below. • The C-factor should be updated each year to reflect that year's approved transmission inflation factor.	$20 million total reduction (revenue requirement)
Rate Base • Accept Hydro One proposal except for adjustments related to capital expenditure cuts	

Capital Expenditures
• OEB staff identified concerns with respect to Hydro One's TSP in areas noted as follows:
  ○ Hazard Function
  ○ Repair vs. Replace Evaluation
  ○ Conductors Replacements
  ○ Customer Engagement
• Reductions related to System Renewal capital budget
• Reductions related to the Kapuskasing Area Reinforcement project
• Reductions related to the Integrated System Operating Centre project
	$328.7 million reduction (capital expenditures) over 2020-2022
	
	$50-$90 million reduction (revenue requirement associated with the capital expenditure reductions)
	
	(Subject to the precise impact on in-service additions)

In-Service Additions • Accept proposed in-service addition forecasting methodology.	In-service additions are impacted by OEB staff's capital expenditure argument
Common Corporate Cost Allocations • Black & Veatch (B&V) Review of Overhead Capitalization Rates • B&V Review of Allocation of Common Corporate Costs • B&V Review of Shared Assets Allocation • The issue of Hydro One's continued use of USGAAP based capitalization policy should be addressed in the 2023-2027 combined rates proceeding.	N/A
Load Forecast • Accept the 3.5% decrease in load forecast from 2018 OEB approved load forecast to 2020 load forecast • Load forecast should be set at 0.0% change for 2020-2022	N/A
Other Revenue • Accept the proposed budget of external revenues • Accept the associated variance accounts of external revenues	N/A
Operations, Maintenance & Administration (OM&A) Costs • Reduction to compensation (impacts OM&A and capital) • Improvements to the presentation of compensation information • Reduction to Sustainment OM&A • Clearer linkage between avoided OM&A savings and newer capital • Productivity savings (see below) **Pension and OPEB costs:** • Accept the proposed recovery methodologies of accrual for OPEB costs and cash for pension costs. • Accept the test period pension and OPEB costs that Hydro One has requested, subject to Hydro One providing a reconciliation between its most recent pension actuarial valuation and the amount being recovered in the test period. • Reject Hydro One's proposal to continue capitalizing the OPEB costs that are no longer permitted by USGAAP, and reject Hydro One's proposal to continue to use the OPEB Cost Deferral Account to capture these costs.	$32 million overall OM&A Impact Increase the revenue requirement by $63 million to incorporate the recognition of OPEB costs that are no longer capitalized. Remove the non-service cost component of OPEBs from capital expenditure amounts. Adjust DVA disposition request to include disposition of the December 31, 2018 balance in

<table>
<tr><td></td><td>the OPEB Cost Deferral account of $22.99 million.</td></tr>
<tr><td>Productivity Savings
It is not clear that productivity savings incorporated into the 2020 test year revenue requirement are genuine productivity savings. OEB staff’s proposed reductions will provide Hydro One an additional incentive to achieve greater productivity.</td><td></td></tr>
<tr><td>Depreciation
Accept proposed depreciation forecasting methodology</td><td>Depreciation expense is impacted by OEB staff’s rate base and capital expenditure arguments</td></tr>
<tr><td>Payments in Lieu of Taxes (PILS)
Accept proposed updated 2020-2022 PILs amounts which reflect an estimate of the impact of Bill C-97 (Capital Cost Allowance (CCA) acceleration), subject to the following:
Recognizing that the PILs amounts may be updated in the draft rate order stage to reflect more current information related to the application of Bill C-97 rules, as well as updated for PILs impacts resulting form the Decision.
Hydro One must quantify the impact of Bill C-97 for 2018 and record the amount in the new sub-account of Account 1592.
Deny Hydro One’s request for a tracking account associated with its appeal before the Divisional Court related to the sharing of IPO tax benefits.
Accept the test period amount of taxes other than income taxes.</td><td>PILs are impacted by OEB staff’s rate base and capital expenditure arguments</td></tr>
<tr><td>Cost of Capital
Accept the cost of capital related proposals
Update to OEB-approved Return on Equity (ROE) will be required at the draft rate order stage of the proceeding</td><td>Cost of capital is impacted by OEB staff’s rate base and capital expenditure arguments</td></tr>
<tr><td>Cost Allocation
Accept proposed methodology used for cost allocation</td><td>N/A</td></tr>
<tr><td>Rate Design
Support proposed Export Transmission Service Rate
Reject at the present time the proposed wording changes to the Uniform Transmission Rates schedules</td><td>N/A</td></tr>
<tr><td>Deferral and Variance Accounts
Accept proposed DVA account disposition.</td><td>Discussed in Pension & OPEBs section.</td></tr>
</table>

• The December 31, 2018 OPEB Cost Deferral account may still be disposed of in the current proceeding depending on the result of Issue 11.
• Reject Hydro One's proposed alternate methodology for its OPEB Asymmetrical Carrying Charge Account and ESM Deferral Account,
• Accept proposed new accounts for 2020-2022 except for the tracking account associated with its appeal before the Divisional Court related to the sharing of IPO tax benefits.
• Accept that no account closures were proposed as part of current proceeding.
• Accept the continuation of existing accounts, except for:
  ◦ The modification Hydro One has proposed related to its In-Service-Capital Additions variance account. Also, Hydro One should submit an updated accounting order for this account.
  ◦ In the event that the OEB does not approve the continuation of the OPEB Cost Deferral account as part of its Decision on Issue 11, then this account should be closed once the balance accumulated within it is approved for disposition.	

Total Impact on Custom Revenue Cap Index (CRCI) Funded 2020-2022 Revenue Requirement ($)	**$62-$102 million reduction (revenue requirement)**

The total impact of OEB staff's argument is to reduce the proposed incremental CRCI funded revenue requirement ($1,556.6 million) for 2020 by approximately $27 million. This results in a CRCI funded revenue requirement decrease relative to the 2019 OEB approved level of approximately 1.5% (which compares to Hydro One's proposed increase of 0.3%).

OEB staff observes that Hydro One developed a comprehensive application that was well organized and articulated. While there are deficiencies in certain areas that OEB staff will address, including evidence of the continuing need of the Custom IR framework as proposed, OEB staff acknowledges that such an application is no small undertaking. In addition, Hydro One provided the necessary information, in a timely manner, which has allowed this proceeding to continue virtually uninterrupted, notwithstanding the need for updates.

The submission that follows is organized in accordance with the approved issues list for this proceeding.[2]

A: GENERAL

1. *Has Hydro One responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous proceedings?*

Background

Hydro One noted that in its previous transmission revenue requirement proceeding,[3] the OEB had directed it to make improvements to certain of its processes and practices, or to prepare and provide certain information in the application. Hydro One stated that it had taken appropriate steps to address all relevant OEB directions, including addressing the OEB's concerns regarding its capital planning and customer engagement processes.

Hydro One also noted that the OEB had directed it to file various reports, including benchmarking studies comparing outcomes that are consistent with the Renewed Regulatory Framework (RRF) and that demonstrate continuous improvement. Hydro One stated that it had responded to these directions by filing numerous internally and externally prepared reports as part of the application.

Hydro One submitted that based on the preceding it had responded appropriately to all relevant OEB directions from previous proceedings.

OEB Staff Submission

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

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[2] Decision on Issues List, Partial Decision on Confidentiality and Procedural Order No. 3 / February 5, 2019 / Schedule A.
[3] EB-2016-0160

2. *Are the bill impacts resulting from Hydro One's proposed revenue requirement reasonable?*

Background

Hydro One stated that the bill impacts resulting from its proposed revenue requirement are reasonable and that to determine the impact of its proposed rate changes on an average transmission-connected and distribution-connected customer's bill, it had adopted the same approach as in the previous proceeding which was approved by the OEB.

The average transmission rate (UTR) increase is 4.1% in 2020 with a 2020 to 2022 three year average increase of 5.5% including the load forecast effect. The 2020 bill impacts for a typical residential medium density R1 customer consuming 750 kWh per month is 0.3% or $0.37, while for a typical General Service Gse customer consuming 2,000 kWh per month is 0.3% or $0.88.

Hydro One submitted that while certain bill impact drivers (e.g. declining load) are out of its control, the relatively small bill impacts resulting from the proposed Rates Revenue Requirement reflect Hydro One's objective of and efforts in appropriately balancing system and asset needs and identified customer preferences regarding outcomes and rates. Hydro One argued that based on the foregoing, the bill impacts resulting from the application are reasonable.

OEB Staff Submission

OEB staff submits that the total bill impacts resulting from this application for the average transmission and distribution connected customers (0.3%) are reasonable as they are significantly below current inflation rates. OEB staff notes that while the transmission rate increases are higher at a 2020-2022 three-year average increase of 5.5%, a significant part of this increase is due to the effects of a declining load forecast.

3. *Were Hydro One's customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?*

Background

Hydro One stated that it had engaged in a broad range of customer engagement activities that had sufficiently and appropriately enabled customer needs to be identified for the formulation of its investment plan. Hydro One submitted that it had gained a clear understanding of the outcomes that customers care about as well as the level and mix of investments that customers wanted to see included in the investment plan. Hydro One stated that its investment planning process had accounted for customer feedback throughout, ensuring that the ultimate plan is responsive to customer needs and preferences and drives value for customers.

Hydro One noted that its transmission operations serve a diverse customer base comprising three customer segments which are distributors, transmission-connected generators and end users located across the province.

Hydro One further noted that serving customers in northern and rural areas presents different challenges from customers located in more populated areas due to sparse populations, remote location of assets and the prevalence of single-phase circuits. On the other hand, customers in non-rural, more populated areas, often share multi-circuit lines with other transmission customers.

Hydro One stated that due to such differences it uses a variety of channels to engage effectively with its customer segments. Hydro One added that these customer engagement activities (both those specific and non-specific to the Transmission System Plan (TSP) are integrated as part of Hydro One's business practices and are fundamental to how Hydro One interacts with and serves its customers. Hydro One states that these activities consist primarily of:

1. The transmission customer engagement survey;
2. Customer satisfaction research and surveys;
3. Large customer account management;
4. The Ontario Grid Control Centre (OGCC) customer operating support group;
5. Large customer conferences
6. Oversight committees and working groups; and
7. Engagement with Indigenous communities.

Transmission Customer Engagement Survey

Hydro One stated that its customer engagement survey for the application, which had been conducted by Innovative Research Group (IRG) in 2017, had enabled it to obtain important feedback regarding customer needs and preferences that directly informed its investment planning. Hydro One further stated that engagement approach incorporated improvements based on feedback received from both the OEB and intervenors in the previous transmission proceeding. Hydro One stated the improvements made had responded to the OEB Decision in the previous proceeding as follows:

1. <u>OEB Direction 1: Timing of Survey</u> – Hydro One stated that the 2017 survey had been completed sufficiently in advance of plan development to allow Hydro One planners to meaningfully incorporate customer feedback when developing the TSP and management to hold a series of cross functional sessions to review relevant findings, trends and customer feedback.

2. <u>OEB Direction 2: Include Feedback from LDC End-Users</u> – Hydro One stated that it had taken steps to include feedback from LDC end-users with the 2017 survey specifically asking LDCs to respond “with your customers in mind” and “with consideration to your customers’ needs,” and to identify whether their responses were informed by their own customer engagement, or other customer research. Hydro One further stated that its account executives had engaged LDCs in discussions regarding the needs of end-users and that the results of LDC customer surveys were also considered during Hydro One’s planning process.

3. <u>OEB Direction 3: Incorporate Input from Indigenous Groups</u> – Hydro One stated that its survey had asked relevant LDC customers whether there was anything they felt it could do to better service the specific needs of First Nations and Métis communities and it had also used its ongoing engagement with these communities to identify their needs and preferences.

4. <u>OEB Direction 4: Ensure Information Presented to Customers is Easy to Understand</u> – Hydro One stated that the 2017 survey had been designed to ensure that its content was clear, sufficiently informative for customers to respond to, and easy for customers to comprehend. Hydro One further stated that in response to a post-survey question, 76% of respondents had indicated that the survey contained the right amount of information.

Customer Satisfaction Research and Surveys

Hydro One stated that it collects feedback from transmission customers through annual customer satisfaction research and uses this data to stay informed of trends that matter most to customers and to guide and improve business practices. Hydro One further stated that the OGCC also surveys satisfaction among its medium and large business customers so as to improve customer service policies, service delivery processes and communications within the OGCC's areas of accountability, such as outage planning and interruption restoration information.

Large Customer Account Management

Hydro One stated that its large customer account management group is an important channel of ongoing customer engagement as it communicates with customers on matters that include connection requests, sustainment and system development plans and projects, and concerns regarding service levels or power quality. Hydro One further noted that executives from this group regularly meet with transmission customers to discuss their needs and ensure action plans are developed as required. Hydro One stated that this open dialogue during the planning of candidate investments ensures customer needs and preferences are accounted for and addressed in a collaborative manner.

OGCC Customer Operating Support Group

Hydro One stated that the OGCC's customer operating support group works directly with transmission customers to efficiently plan real-time outage operations, coordinate planned outages so Hydro One or the customer can complete required work, respond quickly to unexpected outages and coordinate switching activities. Hydro One further stated that as part of its work, this group also organizes bi-annual customer meetings throughout the province to coordinate outage planning activities.

Large Customer Conferences

Hydro One stated that each year it organizes and hosts a large customer conference for all large transmission and distribution (2 MW and up) customers, which provides an opportunity for large customers to hear about Hydro One's plans and initiatives, ask questions, discuss their interests, and raise any concerns they may have.

Oversight Committees and Working Groups

Hydro One stated that it has established various oversight committees and working groups, including the Sarnia Area Reliability Oversight Committee, LDC Working Group, Toronto Hydro Oversight Committee, Nuclear Switchyard Oversight Committees with OPG and Bruce Power, Metrolinx Working Group, and Hydro Ottawa Oversight Committee. Hydro One stated that the purpose of these groups is to engage with and obtain feedback from customers on issues with a high level of customer interest which provides it with valuable early insight regarding future investment needs.

Engagement with Indigenous Communities

Hydro One stated that it has carried out an extensive program of engagement with Indigenous customers and rights holders, which has further informed the formulation of the TSP and is discussed in more detail under Issue 10.

Hydro One concluded that its numerous channels of customer engagement activities had yielded robust and meaningful feedback, in a variety of forms, from its diverse groups of customers. Hydro One added that it had considered and addressed the identified customer needs in its investment planning process and the formulation of proposed spending in the application such that the resulting plans are responsive to those needs and preferences.

OEB Staff Submission

OEB staff submits that Hydro One's customer engagement efforts are generally appropriate, subject to the concerns that are raised with respect to these efforts in the TSP section of this submission and under Issue 24 with respect to the lack of engagement with customers potentially affected by proposed amendments to the Terms and Conditions of the UTR Schedules. OEB staff also has some concerns with the lack of direct input from distribution customers as to their views on the proposed increases incorporated into the IRG survey.

OEB staff notes that the combined transmission and distribution application that is to be filed by Hydro One for 2023 and subsequent years may allow Hydro One a greater opportunity to get more specific feedback from its distribution customers regarding the proposed transmission rate changes, in addition to those for distribution services.

4. *Is the proposed effective date of January 1, 2020 appropriate?*

Background

Hydro One noted that in the application it had requested that the OEB's rate orders be made effective January 1, 2020. Hydro One observed that the application had been filed on March 21, 2019, which is over nine months prior to the requested effective date. Hydro One submitted that this has provided a sufficient period to allow for the requested effective date, particularly given that the application is for a rate period of only three years.

Hydro One further noted that the application was deemed complete by the OEB as originally filed and that Hydro One had conducted itself appropriately and met all filing deadlines that the OEB established throughout the proceeding. Hydro One argued that, as such, the proposed effective date of January 1, 2020 is appropriate.

Hydro One also requested an interim rate order to (1) make its current transmission revenue requirement and charges interim as of January 1, 2020 and (2) establish a Foregone Transmission Revenue Deferral Account to recover the differences between the revenues earned under interim rates and the revenues that would have been earned based on final rates from the January 1, 2020 effective date until the implementation date of the final rates. Hydro One requested that the OEB proceed to issue the requested interim order prior to the end of 2019 given that the schedule for the proceeding extends into the early part of 2020.

OEB Staff Submission

OEB staff submits that the proposed effective date of January 1, 2020 is appropriate as Hydro One has met all of the filing deadlines established by the OEB. OEB staff also agrees with Hydro One that given the schedule for the proceeding extends into the early part of 2020, it is appropriate that the OEB make Hydro One's current transmission revenue requirement and charges effective on an interim basis as of January 1, 2020. OEB staff will make its submissions on Hydro One's proposed Foregone Transmission Revenue Deferral Account under Issue 23.

B: CUSTOM APPLICATION

5. *Are all elements of Hydro One's proposed Custom Incentive Rate framework for the determination of revenue requirement appropriate?*

Background

Hydro One has proposed a three-year Custom IR plan that consists of rebasing its revenue requirement for 2020 on a cost of service basis, followed by annual adjustments of the revenue requirement for 2021 and 2022 using a revenue cap which includes a capital adjustment factor (Capital-factor or C-factor).

Hydro One retained Power Systems Engineering, Inc. (PSE) to do an independent study on electricity transmission productivity (Total Factor Productivity or TFP) and total cost benchmarking, based on the historical (and forecasted, for total cost benchmarking) of Hydro One and a sample of U.S. electricity transmitters.[4] PSE's research also made a recommendation for a transmission-specific inflation factor. PSE's evidence in the original pre-filed evidence was an update of a similar report filed and considered in the Hydro One Sault Ste. Marie case dealt with in late 2018 and early 2019.[5] On October 15, 2019, Hydro One, on behalf of PSE, filed an unsolicited reply report (Reply Report); OEB staff addresses the Reply Report in its submissions following.

OEB staff retained Pacific Economics Group LLC (PEG) to assess Hydro One's proposed revenue cap plan and PSE's evidence. PEG conducted its own analyses, based largely on PSE's data and models, but also did its own analyses. PEG filed its evidence on September 5, 2019.[6]

PSE and PEG responded to interrogatories on their respective reports, participated in the Technical Conference, and witnesses for PSE and PEG testified at the oral hearing. OEB staff notes that, since PSE's evidence and Hydro One's revenue cap framework were very similar to, and largely based on the same analyses used to support Hydro One Sault Ste. Marie's (Hydro One SSM) revenue cap plan in that recently concluded case, the OEB adopted the record of PSE's and PEG's evidence from the case on the record of this Application.[7] This avoided unnecessary and duplicative interrogatories and cross-examination.

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[4] Exhibit A/Tab 4/Schedule 1/Attachment 1
[5] EB-2018-0218
[6] Exhibit M1
[7] OEB letter, EB-2019-0082, July 4, 2019

OEB Staff Submission

Revenue Cap Formula

For 2021 and 2022, Hydro One proposed that the prior year's revenue requirement be adjusted by a revenue cap formula.[8] Mathematically,

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

where

RR_t would be the revenue requirement for year t
RCI_t would be the revenue cap index for year t

The revenue cap index was calculated formulaically for each year as:

$$RCI_t = I_t - X + C_t \quad (2)$$

where

I_t would be the transmission-specific inflation factor as calculated and issued by the OEB for rate adjustments for that year
X would be the X-factor, composed of a base productivity (base X) and stretch factor, and would be fixed over the plan term (i.e., the same for the two years)
C_t would be the capital factor (C-factor) adjustment to reflect the impact of incremental capital spends per Hydro One's TSP for that year.

OEB staff notes that Hydro One's formula for the RCI above is a simplification of the general revenue cap formula:

$$RCI_t = I_t - X + g + C_t \pm Z_t \quad (3)$$

where

g is a growth factor
Z_t is an adjustment for qualifying exogenous events that reflect unavoidable and material cost changes outside of the firm's ability to predict or control

The issue of growth, first raised by OEB staff in the Hydro One SSM case, was discussed in this case again, and OEB staff makes a submission on this later on. OEB staff also considers it appropriate to include the Z-factor in the formula for completeness. However, as is discussed in this submission, the adoption of equation (3) does not have any material impact of the revenue cap formula for Hydro One's Custom IR plan.

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[8] Exhibit A/Tab 4/Schedule 1/pp. 1-3

The OEB has specified that a revenue cap formula is a permissible form of incentive regulation for electricity transmitters.[9] The OEB also recently approved a revenue cap plan for Hydro One SSM.[10] Hydro One's proposed revenue cap formula for its Custom IR plan differs only in including the C-factor and is the element that effectively makes this application a Custom IR proposal as opposed to a Revenue Cap IR application.

OEB staff submits that, with the adoption of equation (3) for the RCI, Hydro One's proposed revenue cap formula is appropriate for its Custom IR plan, and is consistent with the OEB's rate-setting policies. However, OEB staff makes submissions on the individual parameters of the revenue cap formula, and on other matters, such as the ESM and Off-ramps, in the following sub-sections.

Inflation

Hydro One has proposed an inflation index, an Input Price Index (IPI), based on the OEB's 2-factor IPI methodology first adopted for electricity distributors, but with weightings that are more representative of the electricity transmission sector for the labour and non-labour (i.e., capital and materials) components. The proposed weights are 12% labour and 88% non-labour, representative of the very capital-intensive transmission network and operations. The derivation of the weights is based on an analysis in PSE's evidence, and reflects the weights of Hydro One and the sample of U.S. utilities' transmission operations used in PSE's TFP and total cost benchmarking analyses.

OEB staff submits that it is appropriate that the weights be representative of the sector as a whole, and not of one single utility. OEB staff accepts that electricity transmission, similar to what was also found for OPG's regulated hydroelectric generating stations, is more capital-intensive than is electricity distribution. This makes sense, as transmitters deal with fewer customers, particularly end use residential and commercial customers, compared to distributors. Also, transmission assets are, in large part, both expensive and have long useful lives, so that most costs are largely related to the initial construction and investment. OEB staff submits that the proposed labour and non-labour weights are reasonable.

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[9] *Handbook for Utility Rate Applications*, October 13, 2016, p. 24, *Filing Requirements For Electricity Transmission Applications: Chapter 2: Revenue Requirement Applications*, February 11, 2016, p. 1

[10] EB-2018-0218, Decision and Order, June 20, 2019

OEB staff notes that the OEB already approved this same IPI methodology for another transmitter, Hydro One's affiliate, Hydro One SSM, in that transmitter's revenue cap plan.[11] The OEB also approved the use of this IPI in the single-year revenue requirement update for 2019 for Hydro One.[12] OEB staff concurs that the inflation index should be representative of the sector, and takes no issue with Hydro One's proposed inflation factor.

The transmission IPI will be calculated annually, and communicated by, the OEB, once approved, as the OEB currently does for the IPIs for electricity distribution and for Ontario Power Generation Inc.'s hydroelectric generating assets price cap plans. Based on data extracted from Statistics Canada in September 2019, and also used for the calculation of two-factor IPIs for electricity distribution and for Ontario Power Generation, OEB staff submits that the two-factor IPI for Hydro One's plan for 2020 would be 1.8%, consistent with testimony by Hydro One.[13] The calculations are shown in the following table.

Table 2

2020 Input Price Index for Electricity Transmission Revenue Cap Plans

	Inputs and Assumptions											
Year	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI	
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual	Annual % Change
2017	108	108.5	108.3	109	108.45			$ 992.42			106.5	
2018	109.4	109.8	110.5	111.1	110.200	**1.6%**	**86%**	$1,021.40	**2.9%**	**14%**	**108.4**	**1.8%**

Sources:

- GDP-IPI (FDD): Statistics Canada, Table 36-10-0106-01 (formerly CANSIM 380-0066) - Price Indexes, gross domestic product, quarterly (2012 = 100 unless otherwise noted) - 2019 Q2, data accessed September 13, 2019
- Average Weekly Earnings (AWE): Statistics Canada, Table 14-10-0204-01 (formerly CANSIM 281-0027), Ontario, all businesses excluding unclassified, annual (current dollars), data accessed September 13, 2019

Data accessed September 13, 2019

X-factor, including the components of base productivity and stretch factor

The X-factor is the main parameter of revenue cap and price cap formulae that acts as a (partial) offset to input price inflation. It acts as a proxy for the productivity and efficiency

[11] *Ibid*, pp. 15-16
[12] EB-2018-0130, Decision and Order, April 25, 2019, p. 7
[13] Oral Hearing Tr., Vol. 8, November 1, 2019, p. 18

increases that firms in competitive industries must strive for to survive against their competitors and to maintain and, hopefully, increase customers' demand for their products and services. And while firms, and their shareholders, would like to retain all of the achieved productivity gains, they will find that some of these will be shared back to customers due to market pressures.

The X-factor is based on two components:

- A base X-factor (productivity factor) which is derived from a historical analysis of total factor productivity (TFP) (or multi-factor productivity (MFP) if not all inputs and outputs are known). This analysis is based on the sector or a sample of firms in the sector, and not on the applicant utility alone.

- A stretch factor representing the sharing of incremental productivity gains that the utility should be able to achieve from the increased flexibility that the firm has under a multi-year and formulaic incentive rate plan relative to what it may have under traditional cost of service regulation. A stretch factor is often first used when the firm switches from cost of service to incentive regulation, and reflects the fact that the firm should be able to improve on its historic productivity because of the increased flexibility it has with more light-handed regulation. The OEB also has maintained the stretch factor to provide an incentive for less efficient firms to become more efficient while recognizing that historically efficient firms may face more challenges. While stretch factors are often established based on informed but qualitative judgement, the OEB relies more on quantitative analyses benchmarking the costs of utilities to other utilities, and taking into account business environment drivers, to establish stretch factors.[14]

Hydro One has proposed an X-factor of 0%, composed of base X and stretch factors both of 0%. This is supported by PSE, based on PSE's evidence.

PSE's evidence as filed in Hydro One's application, was a minor update of the same evidence filed and considered in the Hydro One SSM proceeding. (OEB staff address the updated evidence in the Reply Report filed on October 15, 2019 later in this submission.) PSE noted the nature and extent of the updates in its evidence from that filed in the Hydro One SSM case.[15]

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[14] EB-2017-0306/-0307, Decision and Order, August 30, 2018, pp. 26-28

[15] Exhibit A/Tab 4/Schedule 1/Attachment 1/p. 4, Exhibit I/Tab 1/Schedule 8

Starting from its evidence filed in the Hydro One SSM case[16] and PSE's updated evidence and "working papers",[17] PEG updated its evidence and proposed an overall X-factor of 0.05, composed of a base X of -0.25 and a stretch factor of 0.30.

(i) Base X

PSE used a sample of U.S. transmitters and Hydro One for its sample in order to estimate the historical TFP for the electricity transmission sector. PEG started from PSE's sample, but added more historical years of data, and did its own TFP analysis. The following table summarizes the TFP results of PSE and PEG from the Hydro One SSM and the current Hydro One cases.

Table 3
Summary of TFP Results of PSE and PEG

Consultant	**PSE**			**PEG**	
Case	EB-2018-2018 (Hydro One SSM)	EB-2019-0082 (Hydro One Tx)		EB-2018-2018 (Hydro One SSM)	EB-2019-0082 (Hydro One Tx)
Document	Exhibit D/1/1/ Attachment 1	Exhibit A/4/1/ Attachment 1	"Reply Report"[18]	Exhibit M1	Exhibit M1
Sample	Hydro One, 47 U.S. utilities	Hydro One, 47 U.S. utilities	Hydro One, 47 U.S. utilities	Hydro One, 44 U.S. utilities	Hydro One, 43 U.S. utilities
Year Range	2004-2016	2004-2016	2004-2018	1996-2016	1996-2016
Sector TFP	-1.71%	-1.45%	-1.61%	-0.34%	-0.25%

OEB staff submitted in the Hydro One SSM case, that PSE's estimated TFP for electricity transmission did not appear reasonable.[19] OEB staff maintains this position in this

[16] EB-2018-0218, Exhibit M1 and associated interrogatory responses filed in Exhibit L1, and both adopted on the record in this proceeding.

[17] The "working papers" of both PSE and PEG consist of spreadsheets with the data for all utilities used in the TFP and cost benchmarking analyses, software and program codes and other documentation to enable replication of the results. Both PSE's and PEG's "working papers" have been afforded confidential status by the OEB.

[18] OEB staff has included the updated TFP analysis from the "reply report" for completeness. However, as is discussed later in this submission, OEB staff submits that the "reply report" should carry little if any weight, as the new evidence could not be properly tested due to the "reply report" being filed less than one week prior to the oral hearing.

[19] EB-2018-0218, OEB Staff Submission, April 12, 2019, p. 22

proceeding. OEB staff's concern in this area is that a value of -1.61% annual TFP means that, for the period 2004 to 2018, the aggregate decline in electricity transmission productivity for the sample – representing a large portion of North American electricity transmission – would be 100% - $(1 – 0.0161)^{14}$ = 20.89%.

During Examination-in-Chief, PEG noted how the work on TFP and total cost benchmarking done in the Hydro One SSM case and quickly updated in this case are amongst the first such studies of electricity transmission, particularly in North America.[20] PEG testified that there have been factors, such as restructuring with RTOs (Regional Transmission Operators) in the U.S. that, in PEG's expert opinion, have reduced productivity for a number of U.S. utilities.

OEB staff submits that there are other factors that have contributed to lower output that have affected many transmission utilities. Energy conservation is one. Macroeconomic changes, such as aging workforces and populations, and shifting from manufacturing to more service-oriented economies, also come into play. However, other than the financial downturn in 2008-2009, the economy has been positive with more gradual but sustained growth.

Measuring TFP involves a sophisticated econometric modelling approach that attempts to measure the ratio of the rate of change of outputs (products made and services provided) to inputs (capital assets and equipment, materials, and labour) that a sector (or a sample of firms in the sector). Further, econometricians must also deal with issues of the availability and quality of data in undertaking these analyses.

Often, the inputs to production (i.e., capital equipment and network assets, labour, materials) are fairly complete and accurate, as they are based on largely on accounting data, which are converted into an index series for input quantities through deflating by input price series and aggregated with cost or revenue weight shares.

Measuring outputs may be more problematic for some sectors and firms. Here, PSE, and PEG, are using two output measures – ratcheted peak demand and km. of line. OEB staff concurs that these are likely the two most significant output measures for transmitters. However, there may be others. For example, the growth of renewable generation – wind and solar in particular – may be resulting in increased interconnections

[20] Oral Hearing Tr., Vol. 9, November 4, 2019, pp. 46-51

to supply.[21] Increased reliability, both due to technology as well as cybersecurity, may also be changing.[22] Some of these outputs may be difficult to define and measure. Their omission may not be meaningful *if* these outputs are positively correlated with ratcheted peak demand and km. of line. However, this may not be the case.

As PEG has noted, the TFP and total cost benchmarking analyses that have been filed by PSE and itself in the Hydro One SSM and updated in this case are amongst the first of their kind, particularly for North America. The data and the models are not as well developed and tested as is the case for electricity and natural gas distribution, where there is extensive experience here in Ontario, going back as far as 1999.[23]

OEB staff submits that PEG's TFP results are more plausible, and its explanations for the methodological and results differences are more reasonable. However, while accepting that transmission sector TFP in the past twenty years or so may be negative for reasons including structural change, natural and promoted conservation effect, and macroeconomic economic changes, OEB staff does not believe that a transmission sector TFP in the range of -1.6% is credible, even for the shortened time period.

As Hydro One and PSE acknowledge, the OEB has generally determined that a base X-factor less than zero is not reasonable or sustainable in the long run.[24] In this Application, they have proposed a zero X-factor, but on the premise that it is a combination of a -1.61% base X-factor offset by an implicit stretch factor of +1.61%. For this reason, PSE and Hydro One propose no separate stretch factor; this is discussed further below.

In contrast, PEG has proposed a -0.25% base X-factor based on its TFP analysis, with a separate stretch factor of +0.3% (i.e., an overall X-factor of +0.05%). PEG's analysis is based on a longer time period (1995 to 2016, versus 2004 to 2016 in PSE's updated evidence filed in Hydro One's application). OEB staff submits that PEG's analysis, based on a longer time frame, and its explanations on why it believes that structural changes, particularly affecting the U.S. transmitters beginning around 2005, are likely drivers for

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[21] *Ibid*, p. 142. PEG mentions negative productivity transmitters in California, Great Plains and western states where the utilities build their networks out to remote wind-power sites.

[22] OEB staff mentions these, as Hydro One pointed to increasing cost expenditures for some of these types of services during its cross-examination of PEG. Oral Hearing Tr., Vol. 9, *op. cit*.,, pp. 147-150. While Hydro One focused on the <u>costs</u> in these areas, OEB staff submits that there must have been some <u>outcome</u> (i.e., <u>output</u>) for the costs incurred. These may not be directed correlated with ratcheted peak demand or km. of line used as the outputs in the TFP analyses.

[23] RP-1999-0034, for the development of the Electricity Rate Handbook for 1st Generation Performance-based Regulation for Ontario electricity distributors.

[24] e.g., Exhibit A/Tab 4/Schedule 1/Attachment 1, pp. 13, 52, "Reply Report", p. 2, AiC, p. 25

the materially negative TFP calculated by PSE for its shorter time period, provides more reasonable numbers.

Nonetheless, OEB staff acknowledges, and concurs with, the OEB's perspective, as also noted by Hydro One and PSE, that, in the long run, the expected TFP for a sector, particularly one that is essential to our modern economy and society, should be non-negative. OEB staff submits that a zero base X-factor is reasonable for the transmission sector at this time, based on our submissions above.

While accepting zero as the base productivity factor, OEB staff submits that an additional and positive stretch factor is also appropriate, and is both consistent with and necessary, in order to incent "continuous improvement", an objective clearly articulated in the Rate Handbook.[25]

(ii) Stretch factor

PSE has recommended a stretch factor value of zero, based on its total cost benchmarking of Hydro One's transmission operations against a sample of 56 U.S. utilities. Hydro One has proposed a zero stretch factor based on PSE's analysis.

As noted earlier, PSE's evidence filed in the original Application is a minor update of its evidence filed in the earlier Hydro One SSM proceeding. PSE's analyses are relatively unchanged and its recommendations are unaltered. In PSE's Reply Report, filed on May 31, 2019, PSE extended the historical time period for the analysis from 2004 to 2018. However, its recommendations are unchanged.

PSE recommends the zero stretch factor for two reasons:

- First, its total cost benchmarking analysis suggests that Hydro One is a superior cost performer relative to the sample of U.S. utilities' transmission operations. While its cost benchmarking performance declines over the forecasted 2020-2022 plan period, in large part due to the increased capital expenditures, it still remains a good cost performer, taking into account the characteristics of its service territory and customer base, relative to the U.S. utilities based on the estimated cost model.

[25] Rate Handbook, p. 3

- Second, PSE argues that its recommended X-factor of zero implicitly incorporates a large stretch-factor of 1.61% since the base sector TFP for the transmission sector is -1.61%, per the updated evidence in the Reply Report.

PEG, recommends a stretch factor of 0.30%, based on its analysis that suggests that Hydro One is within the normal bounds of cost performance. The 0.30% stretch factor for “normal” performance is adopted from the OEB’s stretch factor range for electricity distributors, which ranges from 0% (for superior cost performance) to 0.6% (for the poorest cost performance). As with its TFP, PEG uses a longer time range, from 1995 to 2016, compared to PSE, whose cost benchmarking analyses begin in 2004.

PSE, in its Reply Report, criticizes PEG’s analysis on a number of points and asserts that PSE’s analysis is superior, for a number of reasons, including:

- Use of the Driscoll-Kraay estimation method for correcting for heteroscedasticity and autocorrelation,[26] as opposed to the Generalized Least Squares approach used by PEG
- The Ordinary Least Squares (OLS) estimators are unbiased and optimal, after making the corrections for heteroscedasticity and autocorrelation
- PSE claims that PEG’s cost benchmarking results show temporal aberrations as they show a cyclical pattern of deviating from zero over time. PSE attributes this to the need for a quadratic term of a time trend variable.

PSE provided some further explanation during the oral hearing on this.[27]

While having had little chance to test the updated evidence in PSE’s “reply report”, PEG provided further explanations during its Examination-in-Chief and oral testimony.[28]
OEB staff concurs with PEG’s explanations. OEB staff discusses subsequently in this submission its significant concerns about the late filing of PSE’s Reply Report which did not allow for proper discovery to take place.

[26] Heteroskedasticity refers to the variance of the error terms of the model not being constant. Autocorrelation, also referred to as serial correlation, refers to error terms, while still stochastic and random, being correlated from one time period to the next. Both of these characteristics are commonly encountered in pooled (time series-cross-sectional) statistical and econometric analyses. Various approaches, such as estimation techniques and different model functional forms (e.g. double-log or translog) can be used to correct for present heteroscedasticity and/or autocorrelation.
[27] Oral Hearing Tr., Vol. 7 (October 31, 2019), pp. 155-168
[28] Oral Hearing Tr., Vol. 9, *op. cit*., pp. 46-63, 85-86

OEB staff thus submits that a stretch factor of 0.3% is reasonable, based on PEG's analysis. OEB staff also notes that the OEB also approved a 0.3% stretch factor for Hydro One SSM.[29]

Taken together, OEB staff proposes an X-factor of 0.3%, composed of a base X of 0.0% and a stretch factor of 0.3%.

C-factor and incremental capital stretch factor (S-factor)

(i) C-factor

The unique feature of Hydro One's proposed Custom IR revenue cap plan is the addition of a capital-factor (C-factor) in the formula. The purpose of the C-factor is to proxy the additional revenue requirement of forecasted capital expenditures (in-service additions) above and beyond what is factored in and recoverable from the established revenue requirement as adjusted by inflation less productivity each year.

The C-factor concept was first introduced and approved for Toronto Hydro-Electric System Limited's (Toronto Hydro's) 2015-2019 Custom IR plan.[30] It was also proposed and approved for Hydro One's 2018-2022 Custom IR plan for distribution rates,[31] and is also under consideration in Toronto Hydro's current Custom IR application for 2020-2024 distribution rates.[32] This current Application is the first revenue cap application for a utility's electricity transmission revenue requirement where a C-factor has been proposed.

The OEB has thus seen and approved the C-factor methodology as a mechanism for reflecting a utility's capital requirements in a multi-year Custom IR plan. In this light, OEB staff submits that Hydro One's proposed C-factor is reasonable on a conceptual basis, with two qualifications:

- First, the need for and appropriateness of a C-factor is established based on a review of the utility's capital system plan (Transmission System Plan or TSP for an

[29] EB-2018-0218
[30] EB-2014-0116
[31] EB-2017-0049
[32] EB-2018-0165

electricity transmitter). OEB staff makes its submissions on Hydro One's TSP later in this submission.

- Second, while the first C-factor for Toronto Hydro's 2015-2019 Custom IR plan[33] had no stretch factor and thus acted to pass through all incremental capital-related revenue requirement (i.e., the utility's full capital plan and budget as documented in its DSP was recovered over the plan term), beginning with Hydro One's 2018-2022 Custom IR plan,[34] consideration has been given on the need of an incremental stretch factor (S-factor) as part of the C-factor in order to incent the utility to seek additional productivity gains on its forecasted capital plan and budget. OEB staff believes that an S-factor on the C-factor, in order to provide additional incentives for the utility to seek productivity and cost efficiencies on its forecasted capital plan and budget is appropriate and consistent with the OEB's rate-making policies and objectives as articulated in the Rate Handbook. OEB staff makes its submissions on the S-factor below.

(ii) S-factor

The concept that the C-factor, as first approved for Toronto Hydro's 2015-2019 plan, did not contain any incentive for a utility to seek productivity gains or cost efficiencies in its forecasted capital, was first discussed during Hydro One's 2018-2022 Distribution Custom IR plan proceeding. PEG explained at that time that the base C-factor thus had weaker regulatory incentive power than did the OEB's Advanced Capital Modules/Incremental Capital Module (ACM/ICM) options for incremental capital funding during price cap plans, due to the 10% deadband in the ICM materiality threshold. In its decision on Hydro One's distribution plan, the OEB added an additional stretch factor of 0.15% on the C-factor to deal with that concern.[35]

In its testimony, PEG discussed its work in the Toronto Hydro Custom IR proceeding and in this proceeding, to establish a more conceptual basis for this incremental stretch factor on capital, which PEG terms an S-factor.[36] In its evidence in the current Toronto Hydro Custom IR application, PEG has done additional conceptual work to equate the S-factor

[33] EB-2014-0116
[34] EB-2017-0049
[35] EB-2017-0049, Decision and Order, March 7, 2019, pp. 31-33
[36] Oral Hearing Tr., Vol. 9, *op. cit*., pp. 102-103

to have similar incentive power to the ICM materiality threshold, including the 10% deadband.[37] The OEB is currently deliberating on that application.

PEG has expanded on that work in its updated evidence in this proceeding, both in its evidence[38] and in responses to interrogatories.[39]

In this proceeding, Hydro One has proposed no S-factor, and PSE supports Hydro One's proposal.

PEG has proposed an S-factor of 0.62%. However, the S-factor that equates to the ICM materiality threshold also depends on the X-factor, including the component stretch-factor; the relationship is inverse – as the X-factor increases, the S-factor decreases.[40] This is logical, as the X-factor of the inflation less productivity (I –X) formula is applied equally to both OM&A and capital-related components of the total revenue requirement and thus provides some incentive for capital cost efficiencies, with less thus needed to be incented by the S-factor.

Thus, PEG's proposed S-factor of 0.31%, as corrected,[41] assumes the X-factor of 0% as proposed by Hydro One. Based on PEG's spreadsheet showing its S-factor derivation,[42] Hydro One's counsel cross-examined PEG on this relationship, with the suggestion that an X-factor of 0.3% would largely eliminate the need for the S-factor (i.e., the S-factor should have a value of zero).[43]

OEB staff recognizes the inverse relationship between the X-factor and the S-factor. However, PEG explained further that while its work on the S-factor advances the conceptual basis for having an incremental stretch on a capital factor, there is more work that could be done. PEG also explained that the S-factor was one approach for incenting capital cost efficiencies.[44]

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[37] EB-2018-0165. PEG's evidence is Exhibit M1, filed March 20, 2019. PEG's response to SEC-13 (Exhibit L1/Tab 5/Schedule 13) provided PEG's theoretical derivation of the S-factor to equate to the ICM materiality threshold.

[38] Exhibit M1, filed September 5, 2019

[39] Oral Hearing Tr., Vol. 9, *op. cit*., pp. 94-102. See also Exhibit L1/Tab 1/Schedules 12, 13, 16, 17, 20, Exhibit L1/Tab 4/Schedule 3

[40] Oral Hearing Transcript, Vol. 9 *op. cit.*, p. 58

[41] Oral Hearing Transcript, Vol. 9, *op. cit*., p. 105

[42] Referenced in Exhibit L1/Tab 1/Schedule 16, filed publicly October 25, 2019

[43] Oral Hearing Transcript, Vol. 9, *op. cit*., p. 106

[44] *Ibid*, pp. 107-111. Also Exhibit L1/Tab 4/Schedules 2 and 5

OEB staff believes that PEG's efforts to develop the S-factor from a conceptual basis and relating it to the ACM/ICM materiality threshold is an advancement in the balancing of the objective of continuous improvement with capital funding needs of Custom IR applications including C-factors. However, OEB staff concurs with PEG that some further development is still warranted on the S-factor methodology to provide the "right" incentive for productivity improvements versus capital increases.[45] The OEB must still make a decision on the Custom IR framework in this current application.

In this instance, OEB staff submits that a 0.15% S-factor on the C-factor is reasonable, and in alignment with its proposal for a 0.3% X-factor, as discussed above. OEB staff advances four reasons for this:

- First OEB staff concurs with PEG's comments, and agrees that further improvements could be made to the S-factor methodology, and that the relationship between the X-factor and the S-factor is not as simple as Hydro One suggested during the oral cross-examination of PEG that the S-factor should actually turn negative for larger values of X.[46] In the real world, there should remain some incentive for cost containment.

- Second, in view of the OEB's expectation for productivity improvements that, as targets in a Custom IR plan, are no lower than what would be expected under a price (or revenue) cap IR plan, consistent with the OEB's objective for "continuous improvement" under the RRF,[47] OEB staff submits that a non-zero and positive S-factor would be reasonable.

- Further, while Hydro One has advanced the argument that its "progressive productivity" approach introduced in this Application already incorporates productivity savings in its capital budget and forecasted capital additions, and thus that no further incentive for capital savings is needed, this is a new and unproven approach. Various parties, and PEG, have expressed some skepticism on this new concept.[48] OEB staff agrees with PEG and others, and submits that a concrete and non-zero S-factor is a more certain way of ensuring the pursuit of

[45] Oral Hearing Tr., Vol. 9, *op. cit*., pp. 102-107
[46] *Ibid*, pp. 106-107
[47] Rate Handbook, pp. 2, 23-28
[48] Oral Hearing Tr., Vol. 8, *op. cit*., pp. 19-20, 73-76, 80-82, 84-87, Vol. 9, *op. cit*., pp. 111-113

capital efficiencies and productivity by Hydro One and that ratepayers receive a share of realized savings.

- The OEB also approved a 0.15% S-factor for Hydro One's 2018-2022 Custom IR plan for distribution rates, as a means of ensuring that there was an additional incentive for Hydro One to pursue productivity improvements and cost containment in its distribution capital expenditures.[49] This 0.15% S-factor was approved along with a 0.45% X-factor. Recognizing that there are differences in Hydro One's cost benchmarking against samples of peer utilities for distribution and transmission, OEB staff submits that it would be reasonable to adopt a similar 0.15% S-factor along with OEB staff's recommended 0.3% X-factor for transmission (discussed earlier).

Growth

While the growth factor was not originally included in Hydro One's RCI formula, it would typically be included. The OEB also did not include a growth factor in the revenue cap plan that it recently approved for Hydro One SSM.[50]

The omission of the growth factor was again raised in this proceeding. Hydro One, and its expert, PSE, stated that growth in the transmission sector is very close to zero.[51] When questioned by the panel, PSE's witness referred to the output growth measure in its TFP analysis, showing growth to be at 0.01% for the period.[52] PEG's witness also concurred that, while the growth factor should be there, it had no reason to dispute PSE's evidence of little or no growth in the electricity transmission sector.[53]

OEB staff has no reasons to disagree with either expert, and accepts that, based on the evidence available, there is almost no growth in electricity transmission output, at least based on the currently measured output measures of "ratcheted" peak demand and km. of line.

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[49] EB-2017-0049
[50] EB-2018-0218, Decision and Order, *op. cit*., p. 14
[51] Oral Hearing Tr., Vol. 8 *op. cit*., pp. 28-31
[52] Oral Hearing Transcript, Vol. 9, *op. cit*., pp. 31-34
[53] *Ibid*, pp. 75-77, 160-161

Based on the record, and also concurring that, conceptually, a factor with a value of zero is not the same as from omitting the factor (i.e., having no factor in the rate adjustment formula),[54] OEB staff submits that including a growth factor with a value of zero is reasonable for Hydro One's 2020-2022 revenue cap plan.

Z-factor

Hydro One proposes that the OEB's established Z-factor policy and methodology be available during the Custom IR plan, consistent with the OEB's general rate-setting approach as documented in the Rate Handbook. Hydro One is proposing no deviations from the OEB's established approach.[55]

OEB staff submits that Hydro One's proposal for Z-factor treatment is consistent with the OEB's rate-setting policies and is reasonable.

Earnings Sharing Mechanism

Hydro One proposes the following ESM:

> Hydro One proposes to share with customers 50% of any earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE for a test year will use the OEB approved mid-year rate base for that period to avoid double counting with amounts in the proposed capital in-service variance account …[56]

OEB staff submits that Hydro One's proposed ESM is reasonable and compliant with OEB policy.

Off-ramps

Hydro One proposes:

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[54] Oral Hearing Transcript, Vol. 8, *op. cit*., pp. 19, 84-85
[55] Exhibit A/Tab 4/Schedule 1, pp. 11-12
[56] *Ibid*, p. 9

> … to apply the OEB's existing policy with respect to off-ramps. …
>
> Hydro One is therefore proposing to adopt the OEB'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.[57]

OEB staff submits that Hydro One's proposal is reasonable and is compliant with OEB policy.

Proposed Framework for Annual Updates

Hydro One has proposed to file annual updates to revise the revenue requirement per the revenue cap index formula, for January 1 of each of 2020 and 2021, and to provide the resulting Uniform Transmission Rates. Hydro One also proposes that it may also seek disposition of deferral and variance account balances if these are material.[58]

OEB staff submits that Hydro One's proposal is reasonable and compliant with OEB policy and practice, with one exception, pertaining to the updating of the C-factor for each year. In Hydro One's application[59] for 2020 distribution rates under its current approved Custom IR plan.[60] OEB staff is aware that Hydro One's position is that the C-factor is fixed at the annual values per the EB-2017-0049 application and decision. Hydro One has proposed also to fix the C-factor for 2021 and 2022 in this Application.[61]

This is not how the C-factor, as first approved for Toronto Hydro's 2015-2019 Custom IR plan[62] works. In that case, the C-factor is updated to reflect the updated inflation factor:[63]

$$C = C_n - S_{cap} \times (I - X)$$

where:

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[57] *Ibid*, p. 12
[58] *Ibid*, p. 13
[59] EB-2019-0043
[60] EB-2017-0049
[61] Exhibit A/Tab 4/Schedule 1, p. 9, updated June 19, 2019
[62] EB-2014-0116
[63] EB-2014-0116, Toronto Hydro Draft Rate Order, January 22, 2016, pp. 11-12

- C is the C-factor of the (custom) price cap index: $CPCI = I - X + C$
- C_n is the factor that reconciles Toronto Hydro Hydro's approved capital investment within a price cap index, and is determined for a given year by calculating the difference in forecast capital-related revenue requirement between the given year and the prior year, divided by the forecast revenue requirement of the prior year. The quantum C_n reflects the OEB's … determination on capital expenditures [for each year of the plan].
- $S_{cap} \times (I - X)$ is the mechanism that returns to ratepayers funding for capital that would have been provided under the standard price cap index formula, where:
  - S_{cap} for a given year is determined by the proportion of forecast capital related revenue requirement to forecast total revenue requirement.
  - I and X are the same terms as in the CRCI formula.

While C_n is fixed, the C-factor itself is updated annually as it depends on the updated inflation factor approved by the OEB for that year.

OEB staff submits that the methodology approved and used for Toronto Hydro is correct. OEB staff submits that, in these Custom IR applications, the utility is forecasting its capital budget for each year of the plan term, including their forecasted inflation. The concept of the C-factor is that, along with the price or revenue adjustment mechanism and subject to the expected productivity incentives of the X-factor and the S-factor, the utility should be recovering its forecasted capital additions (i.e., capital expenditures that enter service). As the inflation factor varies from year to year, the amount that is recovered through the rates or revenue requirement adjusted for the basic inflation less productivity (I – X), excluding the C-factor, changes. Thus the amount of the capital additions that needs to be accounted for by the C-factor adjustment will also vary from year to year. Hydro One's approach for fixing the C-factor even when the inflation changes means that it will potentially under- or over-recover the revenue requirement for its capital additions in each year. The amount may not be large. However, OEB staff notes that the update of the C-factor as Toronto Hydro did for each year of its 2015-2019 Custom IR plan is formulaic in nature.

OEB staff thus submits that it is the forecasted capital budget (and specifically the forecasted capital additions for each year) that is fixed and approved in the initial application, and not the C-factor itself. OEB staff submits that Hydro One should be ordered to update the C-factor annually as part of the annual application, consistent with the C-factor methodology as approved in Toronto Hydro's previous Custom IR plan.

If the OEB does not wish to generate a methodological difference between distribution and transmission Custom IR plan terms to conclusion in 2022, OEB staff submits that this could be reasonable. However, OEB staff submits that for any future distribution or transmission multi-year plans including a C-factor, the C-factor should be updated annually based on the inflation factor each year.

PSE's Reply Report

Background

OEB staff notes that PSE filed a Reply Report[64] on October 15, 2019, which was less than one week prior to the start of the oral hearing on October 21, 2019. This report had not been mandated in the OEB's procedural directions.

OEB staff further notes that this is the third time in recent years that a PSE report of this kind has been filed by an applicant under similar circumstances, though in neither previous case so near to the beginning of the oral hearing.

The first such occurrence took place in 2015 during Toronto Hydro's first Custom IR application review process.[65] In that case, Toronto Hydro filed the reply report on January 20, 2015, which was almost a month before the commencement of the oral hearing. No testing of the reply report was done prior to the oral hearing, which took place between February 17 and March 3, 2015, but parties cross-examined PSE and PEG during the oral hearing.

The second occurrence took place during Toronto Hydro's current Custom IR application review process.[66] Once again in this proceeding, Toronto Hydro filed the PSE reply report about a month prior to the commencement of the oral hearing.[67] In this case, provision was made for a quick round of interrogatories and replies on this Reply Report within the allowed schedule.[68] The timing was sufficient to allow parties to cross-examine PSE on the reply report during that proceeding.

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[64] Power System Engineering, Inc. *Reply to PEG's Report ("Incentive Regulation for Hydro One Transmission")* October 15, 2019.
[65] EB-2014-0116
[66] EB-2018-0165
[67] EB-2018-0165, PSE "reply report", May 31, 2019
[68] EB-2018-0165, Procedural Order No. 8, June 6, 2019

OEB Staff Submission

OEB staff submits that it would be helpful to parties if the OEB was to provide guidance on the appropriateness of the filing of these types of reply reports in the absence of specific procedural direction to do so and given the timing of the filings. OEB staff notes that the timing of the filing of the Reply Report in this proceeding was particularly problematic in terms of allowing proper discovery to be undertaken.

OEB staff further submits that given the particularly late filing of the PSE Reply Report in this proceeding, which as noted did not allow for proper discovery to take place, this report should be given little or no weight by the OEB in its deliberations on the matters covered by it.

C: PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCORECARD

6. *Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations?*

Background

Hydro One stated[69] that it has taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations. Hydro One noted that the total revenue requirement and resulting rate impacts from the application have been mitigated by $370 million[70] in productivity savings over the three-year application period (2020 to 2022), through defined capital and OM&A initiatives, as well as undefined progressive productivity initiatives for capital. Hydro One stated that it has included the benefit of these savings to ratepayers up front and has taken on the execution risk to deliver its planned work program within a reduced funding envelope.

In the table below, Hydro One identified approximately $704 million in savings opportunities over the 2020-2024 TSP period:

[69] Argument in Chief Page 27 & 28

[70] The $370 million of productivity savings is the sum of $98 million (2020), $126 million (2021), and $146 million (2022) shown in the table “2020-2024 Productivity Savings”

Table 4 – 2020-2024 Productivity Savings

$ millions	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	**259**
Progressive Operations (Defined Capital)	6	12	12	10	10	**49**
Corporate	12	11	9	7	6	**45**
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	**45**
Information Technology	6	9	10	10	10	**44**
Corporate	7	6	5	4	3	**25**
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Progressive Operations (Undefined Capital)	11	27	49	68	81	**237**
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive Productivity						
Progressive Operations (Defined Capital)	6	12	12	10	10	**49**
Progressive Operations (Undefined Capital)	11	27	49	68	81	**237**
Progressive Productivity Placeholder	**17**	**39**	**61**	**78**	**91**	**286**

Hydro One noted that these are savings that have a direct correlation to a budget and/or spending forecast reduction. Hydro One stated that this is consistent with the OEB's direction in the prior transmission decision[71] to "establish firm short-term and long-term targets for productivity improvements and associated reductions in revenue requirement."

Hydro One noted[72] that the $704 million amount represents "Tier 1 Productivity" savings only. Hydro One stated[73] that all Tier 1 validated productivity savings are reflected in its plan, with a direct benefit to customers through reduced revenue requirement. Hydro One stated[74] that additional Tier 2 Productivity savings may be achieved, but such additional savings cannot be forecasted and are not accounted for in the planned savings. The different types of productivity are discussed below.

[71] EB-2016-0160

[72] Exhibit B, Tab 1, Schedule 1, TSP Section 1.6, page 7

[73] Oral Hearing Transcript October 24, 2019, page 71

[74] Exhibit B, Tab 1, Schedule 1, TSP Section 1.6, page 8

Hydro One stated[75] the following regarding its classification of productivity and the approximate associated savings shown in the above table:

<u>Tier 1 Productivity:</u>

Net savings with a direct correlation to a budget and/or spending forecast reduction (i.e. “hard savings” which are monitored, tracked and reported on corporate scorecards.

<u>Tier 2 Productivity:</u>

All unit based savings other than Tier 1 productivity savings which are derived from calculation methodologies approved by Hydro One’s Finance Department. These savings result in Hydro One getting incremental work completed or increased output for the same dollars input (i.e. “more work”), which are not reported on corporate scorecards but which are otherwise monitored and tracked. There are no Tier 2 savings included in this application.

<u>Progressive Productivity:</u>

A further reduction in cost that Hydro One has included in the final transmission business plan in response to concerns that were raised in the OEB’s prior transmission decision regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes.

As is evident from the above table, Progressive Productivity consists of two components, which are:

(i) *Progressive Operations (Defined Capital):* Savings are associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework.
(ii) *Progressive Operations (Undefined Capital):* Savings that are included as a placeholder in Hydro One’s business plan to be allocated to any future initiatives that have not yet been identified.

[75] Exhibit B, Tab 1, Schedule 1, TSP Section 1.6, page 3, 7, 8

Hydro One indicated[76] that progressive productivity represents a forward-looking commitment to find more cost-effective ways of executing its capital work, without having to further defer or delay work to stay within a necessary funding envelope.

Hydro One stated that the concept of progressive productivity does not exist within its OM&A forecast. Hydro One explained[77] that for the most part its OM&A work program is, more or less stable or flat over the planning period in accordance with the formulaic rate setting mechanism.

Hydro One also noted that it is experiencing more growth in its capital work program, which has necessitated a greater focus on productivity in this area. In Hydro One's view, it needed to demonstrate its ability to continue to take costs out of its capital work execution through a variety of methods, some of which are known now, and some of them were more of a forward-looking commitment, hence the progressive productivity element within this application.

OEB Staff Submission

Hydro One stated of its progressive productivity initiatives that:[78]

> By giving the benefits of these savings to customers upfront, the Company has taken on financial and execution risk to deliver its planned work program within a reduced funding envelope. The initiative results in a further push towards a productive culture through the development of more initiatives.

While OEB staff commends Hydro One for undertaking this initiative, OEB staff submits that Hydro One in the present application has still not adequately distinguished what represents a true productivity gain from what is normal due diligence in operating its business. OEB staff submits that the complexity of the approach used by Hydro One as outlined above does not assist in making this distinction.

OEB staff notes in this context that in the most recent distribution decision, the OEB expressed concerns about Hydro One's approach to determining productivity savings, stating that:[79]

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[76] Oral Hearing Transcript October 24, 2019, page 69
[77] Oral Hearing Transcript October 24, 2019, page 71
[78] Undertaking JT1.9
[79] EB-2017-0049 *Decision and Order,* p.57

> …the OEB finds that Hydro One’s presentation of these productivity gains makes it difficult to differentiate between what is a “productivity gain” and what would be an exercise in due diligence in reviewing these potential savings areas to ensure that their costs have been appropriately budgeted.
>
> In future applications, the OEB directs Hydro One to clearly describe the methodology by which any claimed productivity savings are determined and whether these savings represent net cost savings for the company which would translate into reduced costs for the ratepayers.

During the oral phase of the proceeding, OEB staff counsel put this finding to Hydro One and asked how the concerns expressed by the OEB were being met. Hydro One provided a lengthy response to this question,[80] which began as follows:

> MR. JODOIN: Well, I first want to start by saying all of these things are aligned. So becoming more productive, coming up with initiatives to be more productive and drive costs lower and ensuring that we're budgeting for those productivity initiatives, so that when we file our rate applications we can demonstrate lower costs through our revenue requirement are all aligned. They all connect and they should speak to each other absolutely.
>
> In terms of our process and how we bring these things together, productivity exists, I mentioned it yesterday, all throughout the organization. It's included on our team scorecard. It's identified directly in our rate applications, both in our pre-filed evidence and throughout our application.

OEB staff submits that this response was very general and was more a summary of Hydro One’s evidence in the proceeding than a specific response to the question asked.

[80] Transcript, Vol. 6, p. 9 L26 to p. 13 L19.

OEB staff notes in this context that with Hydro One's proposed revenue requirement increasing in this application, it may be difficult for ratepayers to see from a practical point of view how Hydro One's productivity initiatives are translating into reduced costs for them. OEB staff submits that Hydro One needs to make its productivity initiatives more understandable in this context.

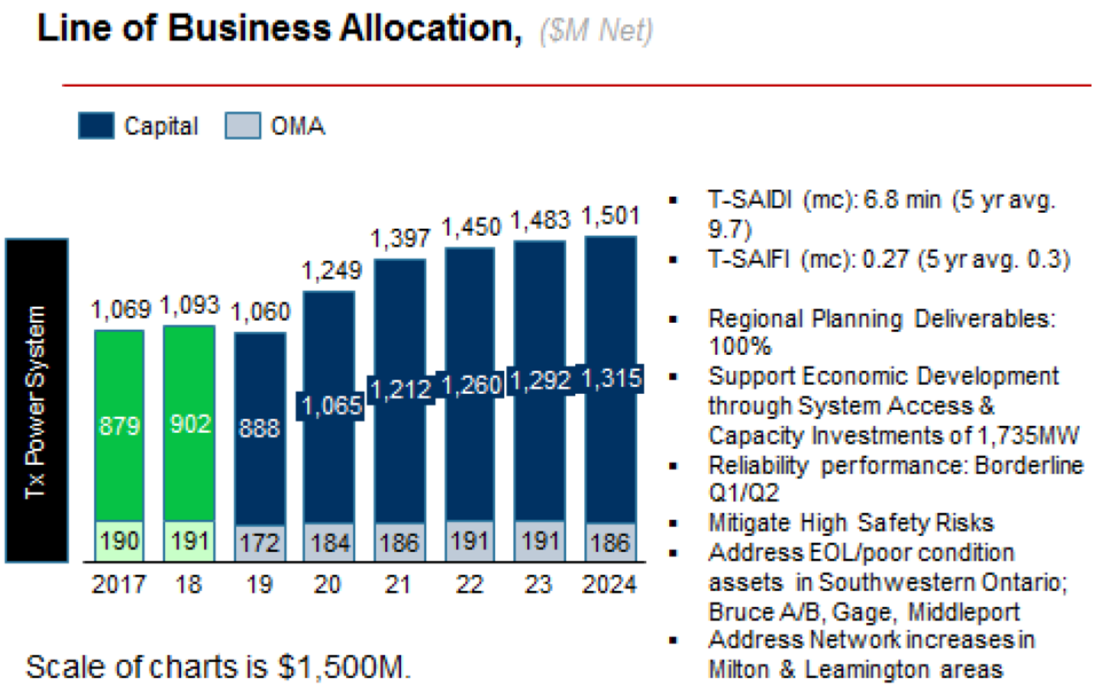
OEB staff further notes that during the proceeding, the concern was raised that the baselines for the various productivity initiatives outlined by Hydro One may not have been entirely clear and that Hydro One had been asked to provide an undertaking to clarify this matter.[81] OEB staff submits that a review of the baseline information provided in that undertaking indicates that the explanations provided were minimal and did not make clear whether a consistent baseline was being applied in determining the productivity savings that were incorporated into the application.

In this context, OEB staff notes that Hydro One stated in its evidence that it had conducted a strategic budget allocation at the beginning of the investment planning process. The basis for this upfront allocation was the expenditure levels included in the previous plan, adjusted for efficiency gains and new strategic directions.[82] Hydro One provided the initial budget allocation for transmission power system in the figure below.

[81] Undertaking JT2.28

[82] Exhibit B-1-1, TSP Section 1.4, Attachment 15, page 3 of 8.

Figure 6.1 Transmission Power System Outcomes



It appears that the capital portion of the bar chart represents capital expenditures excluding general plant because the $879 million for 2017 reconciles with Hydro One's actual capital expenditures for 2017 excluding investments on general plant.[83] Figure 6.1 shows that the initial capital budget for 2020-2022 was at $3,537 million, which is $327.7 million lower than the final proposed amount of $3,864.7 million.

OEB staff understands that the proposed capital expenditures are supported by asset needs and assessments. However, a review of the proposed capital expenditures at each stage of the investment planning process raises the question as to whether the proposed investments were increased after including progressive productivity initiatives in the capital plan.[84]

Hydro One confirmed that the progressive productivity savings were added at the final plan review and approval stage. The proposed capital expenditures went up by $394 million at the final stage from the previous stage.[85] OEB staff submits that it is easy to claim productivity savings if the baselines are higher than they should be, therefore, it is

[83] Exhibit B-1-1, TSP Section 3.3, filed 2019-06-19, page 2 of 20.
[84] Exhibit I-7-28, filed 2019-08-02, page 1 of 1.
[85] Oral Hearing Transcript, Volume 1 Revised, pp. 55-56.

OEB staff's view that this provides additional justification for including an explicit productivity factor in the Custom IR plan.

OEB staff also notes the School Energy Coalition's (SEC) suggestion that if Hydro One wants to take the up-front risk, and if it is unable to meet the targets related to progressive productivity, it should not even plan to ask for that amount in a future rate application through the incorporation of higher capital expenditure levels into in-service adjustments. This suggestion was not accepted by Hydro One.[86]

OEB staff is of the view that SEC's suggestion should not be adopted at the present time for a number of reasons. First, given the concerns noted above about the need to more clearly delineate how productivity savings are separate from normal diligence, OEB staff believes that this matter needs to be dealt with first. OEB staff is concerned that if it is not, considerable time may be spent at future hearings debating exactly what should be included and excluded from the rate base. Second, OEB staff is concerned that the separate tracking of the productivity-separated elements of the rate base from the rest could be complex and time-consuming and increase regulatory burden and costs especially since these elements would have to be tracked over many years. Finally, the establishment of such an approach, in the absence of an agreed-upon approach to determining exactly what productivity savings are, will inevitably provide a disincentive to Hydro One to work to achieve additional productivity gains.

7. *Are the metrics in the proposed scorecard appropriate and do they adequately reflect appropriate outcomes? Do the outcomes adequately reflect customer expectations?*

Background

Hydro One has proposed six additional metrics and removed three metrics from their previous scorecard.[87] The additional metrics are summarized below:

[86] Oral Hearing Transcript October 29, 2019, page 82-83

[87] Exhibit B, TSP Section 1.5, pp.5 and AMPCO IR#18 (b) and (c)

Table 5: Additional Metrics on 2020-2022 Evolved Transmission Scorecard

Performance Outcomes	Performance Categories	Measures
Operational Effectiveness	Asset & Project Management	Transmission System Plan Implementation Progress (%)
		OM&A Program Accomplishment (composite index)
		Capital Program Accomplishment (composite index)
	Cost Control	Line Clearing Cost per kilometer ($/km)
		Brush Control Cost per Hectare ($/Ha)
Public Policy Responsiveness	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right- Sizing	End-of-Life Right-Sizing Assessment Expectation

The removed metrics are summarized below:

Table 6: Removed Metrics from 2017-2018 Transmission Scorecard

Performance Outcomes	Performance Categories	Measures
Operational Effectiveness	Asset & Project Management	In-service additions as % of OEB-approved plan
	Cost Control	Sustainment capital /Gross fixed asset value
Policy Response	Regulatory Compliance	NERC & NPCC Standards Compliance – High impact issues
		NERC & NPCC Standards Compliance – Medium/low impact issues

OEB Staff Submission

OEB staff submits that the removed metrics are appropriate and adequately explained.

OEB staff submits that the metrics in Hydro One's proposed 2020-2022 evolved transmission scorecard are appropriate[88] with one exception which is that system renewal portfolio metrics should be included in Hydro One's proposed 2020-2022 evolved transmission scorecard. OEB staff also believes that Hydro One should propose an end use customer metric in its 2023 to 2027 application.

[88] This can be found in Exhibit. B, TSP Section 1.5, p. 5.

End Use Customer Metric

The OEB required that Hydro One “develop performance indicators that better reflect the satisfaction level of the ultimate end use customer”[89] to be tracked as a metric in its next transmission scorecard.

Hydro One has argued that there is no direct link between its transmission system and the LDCs’ end use customers.[90] In Hydro One’s pre-filed evidence[91] and in response to an interrogatory,[92] the issue of how to include feedback from LDC end-users was discussed. There were three suggestions from LDCs:

(i) continue using the account executive model with the LDC;
(ii) Hydro One to meet with LDCs’ large industrial customers; and
(iii) Hydro One to review LDCs’ survey information.

OEB staff notes that Hydro One does not bypass LDCs to contact LDCs’ customers[93] and it would be at the discretion of the LDCs to allow for Hydro One to meet with LDCs’ large industrial customers or other end use customers. Hydro One commented on the third suggestion in the oral hearing stating that it will be undertaking a review of LDCs survey information in the next application.[94]

OEB staff submits that Hydro One, in keeping with the 2017 Decision and Order, should continue working with LDCs, including Hydro One Distribution, to determine the satisfaction level of the ultimate end use customer to be included in the next scorecard. OEB staff notes that Hydro One Distribution has 1.3 million customers and submits that Hydro One Transmission should leverage its relationship with Hydro One Distribution to determine a metric for distribution customers’ satisfaction level.

[89] EB-2016-0160 Decision and Order, November 1, 2017, pp. 38
[90] Oral Hearing Transcript, Vol. 3, pp. 81
[91] Exhibit B, TSP Section 1.3, pp.28-30
[92] SEC IR # 19.
[93] Oral Hearing Transcript, Vol. 7, pp. 31
[94] Oral Hearing Transcript, Vol. 3, pp. 82

System Renewal Portfolio Metrics

Hydro One has different approaches to develop costs for projects and programs.[95] Projects go through the Capital Delivery Process which refines the scope and cost of individual projects. In other words, each project is unique. Programs costs are forecasted based on the number of units using a unit cost approach, meaning the work is largely replicable between units.

Hydro One proposes to include a Capital Program Composite Score metric which captures six programs under its system renewal budget.[96] This metric has a $1 billion budget from 2020-2024, and the proposed total system renewal budget is $5.5 billion in the same period,[97] which means $4.5 billion of the total system renewal budget or over 80% of the total expenditures are not captured by Hydro One's proposed metric.

The OEB has to be able to track the performance of these projects at a portfolio level to ensure there is operational effectiveness in the delivery of projects. In an undertaking at the technical conference,[98] Hydro One provided portfolio level metrics that track cost, schedule and scope. In the oral hearing, Mr. Spencer indicated that Hydro One has the ability to report on these metrics.[99] Hydro One has also provided targets for the portfolio level metrics.[100]

OEB staff submits that the following system renewal portfolio level metrics be put into the evolved scorecard: (i) the number of projects in-progress and forecasting a major variance or completed with a major variance (+10%) to the OEB approved budget and (ii) value of the projects in-progress and forecasting a major variance or completed with a major variance (+10%) to the OEB approved budget. The portfolio metric should be composed of only projects in system renewal, but excluding the six system renewal programs that are already captured in the Capital Program Composite Score metric. These metrics would allow the OEB to measure the cost performance of projects against the OEB approved budget.

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[95] SEC IR#8

[96] Exhibit B, TSP Section 1.5, pp. 8

[97] Exhibit B, TSP Section 3.3, pp. 15-16

[98] JT 1.16

[99] Oral Hearing Transcript, Vol. 1, pp.117-118

[100] Undertaking J 1.3

8. *What is the status of Hydro One's joint work with the IESO to explore cost effective transmission line loss reduction opportunities and to report on those initiatives?*

Background

The OEB directed Hydro One in its previous transmission decision to work with the Independent Electricity System Operator (IESO) to explore cost effective opportunities for line loss reduction and to report on these initiatives.[101]

Environmental Defence, an intervenor in this proceeding, expressed concerns about the extent of Hydro One's compliance with this directive. During the current proceeding, Hydro One and Environmental Defence agreed to terms of settlement in respect of this issue and included details of the steps that Hydro One will take under the terms of settlement.[102]

On December 9, 2019, Environmental Defence filed its submission in this proceeding.[103] This submission stated that while Environmental Defence was very pleased that Hydro One had agreed to take what it believed are the necessary first steps to meet the OEB's directives regarding transmission losses, more work is needed and that work needs to happen in a more timely fashion.

Environmental Defence argued that Hydro One to date has not made any improvements to its loss mitigation processes, addressed the OEB's concerns, or made any savings in avoided transmission losses in response to the OEB's directives. Environmental Defence, however, expressed the belief that these short-comings will be addressed and agreed with Hydro One on the next steps.

OEB Staff Submission

OEB staff agrees that the basis of the settlement between Hydro One and Environmental Defence represents compliance by Hydro One with the requirements established by the OEB in the previous transmission decision that it explore cost effective opportunities for line loss reduction and to report on these initiatives in this proceeding.

However, OEB staff notes the submissions of Environmental Defence that Hydro One has not yet made any of the necessary improvements or addressed the OEB's concerns

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[101] EB-2016-0160, Decision and Order, November 1, 2017, page 33.
[102] Hydro One Settlement of Issue 8 Letter, October 17, 2019.
[103] EB-2019-0082 Submissions of Environmental Defence, November 9, 2019

regarding transmission losses and submits that the OEB may wish to require Hydro One to file a formal analysis of line loss opportunities.

D: TRANSMISSION SYSTEM PLAN

9. *Are the proposed forecast capital expenditures and in-service additions arising from the transmission system plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, asset condition and benchmarking appropriate and adequately explained?*

Background

Hydro One's proposed capital expenditures are set out in the table below.[104]

Table 7
2020-2022 Proposed Capital Expenditure Summary ($Millions)

Category	2020	2021	2022	Total
System Access	24.8	11.3	11.7	**47.8**
System Renewal	865.2	1,103.1	1,172.8	**3,141.1**
System Service	204.1	148.2	151.8	**504.1**
General Plant	115.4	94.4	94.7	**304.5**
Progressive Productivity	-17.0	-39.0	-61.0	**-117.0**
Directive	-0.3	-0.3	-0.4	**-1.0**
Sub-total	**1,192.2**	**1,317.7**	**1,369.6**	**3,879.5**
Pension Adjustment	-4.2	-5.2	-5.4	**-14.8**
Total	**1,188.0**	**1,312.5**	**1,364.2**	**3,864.7**

The proposed 2020-2022 capital expenditures are $3,864.7 million, which is an increase of 29.8% over the OEB approved level of $2,988.2 million[105] for 2017-2019. The

[104] Exhibit J1.1, filed 2019-10-22, Table 6, page 6 of 10.
[105] Exhibit B-1-1, TSP Section 3.3, updated 2019-06-19, Table 1 and Table 2, pp. 2-3 of 20. For the 2019 rate year, the OEB approved Hydro One's revenue requirement by applying a revenue cap index to the

proposed capital expenditures also represent an increase of $920.1 million[106] (31.1%) over the actual spending for 2017-2019.

The proposed increase in capital spending is driven mostly by investments in the system renewal category, for which Hydro One proposed an average annual increase of 15.2% over the 2020-2022 period.

OEB staff submits that a reduction of $328.7 million (8.5%) to the total 2020-2022 capital expenditures is appropriate. The proposed reductions are summarized in the table below:

Table 8
OEB Staff Suggested Capital Reductions for 2020-2022 ($Millions)

Category	2020	2021	2022	Total
System Renewal	86.8	111.0	120.8	**318.5**
System Service	3.6	2.1	0	**5.7**
General Plant	3.2	1.3	0	**4.5**
Total	**93.6**	**114.3**	**120.8**	**328.7**

OEB staff notes that the reduction it is proposing is an envelope reduction relating to its concerns to be outlined below with Hydro One's proposed system renewal spending and the methodologies used to determine this spending. OEB staff is recommending no cuts in the system access category and the cuts which are proposed in the System Service and General Plant categories are related to concerns with one specific project in each of these categories (specifically the Kapuskasing Area Reinforcement Project and the Integrated System Operating Centre projects respectively.)

Hydro One's proposed in-service additions associated with its proposed capital expenditures are set out in the table below:[107]

approved 2018 level. Therefore, no capital expenditures were specifically approved for 2019. OEB staff used the 2019 forecast capital spending as the proxy of actual/approved expenditures for the purpose of discussion in this submission.

[106] *Ibid.*

[107] Argument in Chief, filed 2019-11-22, Table 9-2, page 46 of 122.

Table 9
2020-2022 Proposed In-Service Additions ($Millions)

	2020	2021	2022	Total
In-Service Capital Additions	1,032.9	1,292.5	1,287.6	**3,613.0**

OEB staff notes that its submissions with respect to reductions to the capital expenditures will have a related impact of reducing in-service additions (and therefore, rate base). The total impact of the proposed capital expenditure reductions on revenue requirement is estimated at between $50 million and $90 million over the 2020-2022 Custom IR term depending on the precise impact on in-service additions.

OEB staff's suggested reductions to capital expenditures are based on the review and analysis of Hydro One's transmission system plan (TSP) during the proceeding. In the following sections, OEB staff will explain in details why the suggested reductions are necessary.

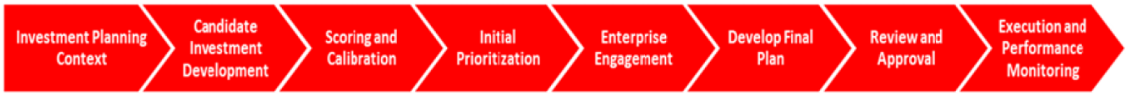
Transmission System Plan

Hydro One's proposed capital expenditures are developed from its 5-year TSP. Hydro One's capital planning process consists of two interrelated functions: the asset management process and the investment planning process. The asset management process involves monitoring and reviewing transmission assets and assessing their condition, assessing system and customer requirements through the regional planning process and customer connection process, as well as identifying and scoping investment candidates. Through the investment planning process, investment candidates are reviewed, prioritized and narrowed into an achievable set of planned investments in specific programs and projects that help drive Hydro One towards achieving its intended outcomes.[108]

Hydro One designed an eight-step investment planning process as shown in Figure 9.1[109] below:

[108] Exhibit A-3-1, filed 2019-06-19, pp. 28-29.
[109] Argument in Chief, filed 2019-11-22, Figure 8-1, page 61 of 122.

Figure 9.1: Improved Eight-Step Investment Planning Process



OEB staff acknowledges that the investment planning process has been improved since the 2017-2018 transmission revenue requirements application, including an enhanced risk assessment framework, better definitions of risk impacts, and the introduction of challenge sessions.[110] However, OEB staff submits that enhancement opportunities still exist in Hydro One's capital planning process. The following sections will explain issues identified by OEB staff.

<u>Hazard Functions (Rate of Removal)</u>

Hydro One engaged the Electric Power Research Institute (EPRI) to review its asset management and asset replacement practices. EPRI produced three studies to derive hazard functions (i.e. rate of removal) for transformers, circuit breakers and overhead conductors.[111]

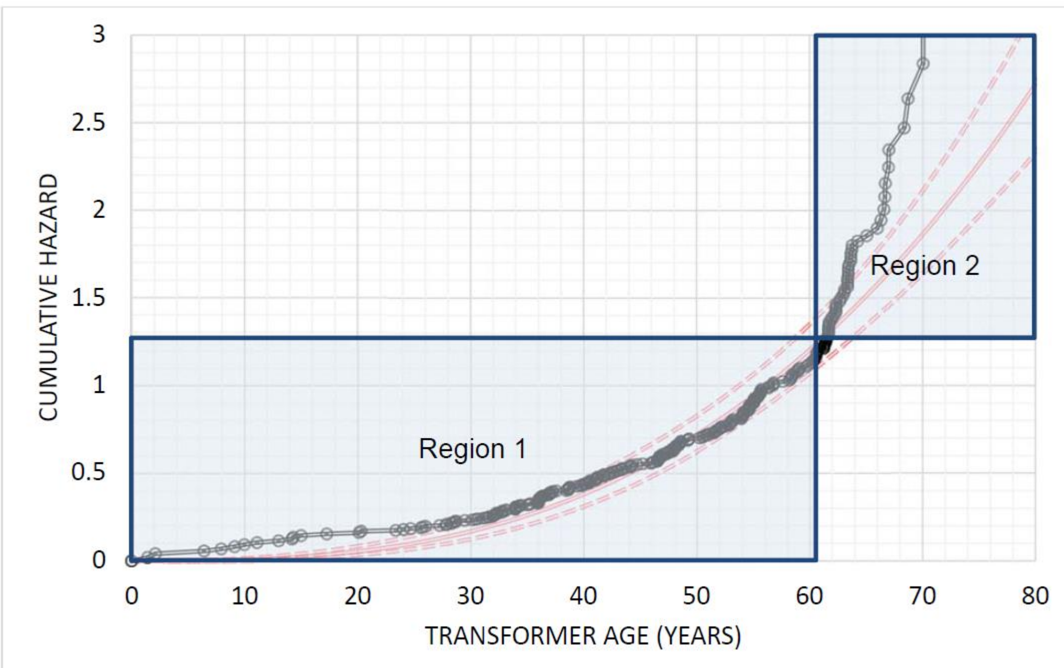
Hydro One stated that EPRI confirms that Hydro One's pacing of replacement for transformers is aligned with EPRI's forecast based on industry best practices. With respect to circuit breakers, although EPRI found that older vintages of circuit breakers are being replaced at a quicker rate than expected, Hydro One explained that the reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report.[112] Regarding overhead conductors, Hydro One changed its conductor expected service life (ESL) from 70 to 90 years as a result of the study. Hydro One stated that it only uses ESL for long term planning purposes and the planned conductor replacements are based on detailed condition assessments, as such, the change of ESL does not affect the current business plan.[113]

EPRI's studies present its analysis of Hydro One's historical condition assessment and replacement data and can be used to project expected replacement needs for planning purposes. For example, to derive the hazard function for transformers, EPRI developed a methodology using advanced statistical techniques for analyzing transformer historical

[110] Argument in Chief, filed 2019-11-22, Figure 8-1, pp. 61-62.
[111] Argument in Chief, filed 2019-11-22, page 68 of 122.
[112] Exhibit B-1-1, TSP Section 3.2, filed 2019-06-19, pp. 13-14 of 28.
[113] Exhibit B-1-1, TSP Section 1.4, filed 2019-06-19, page 10 of 33.

replacements from a number of utilities' datasets. The result of this statistical analysis was a probability distribution of the sample utilities' transformer datasets of in-service and failures (EPRI named the sample probability distribution as prior distribution). EPRI applied the statistical result to Hydro One's transmission substation transformer fleet and developed a new, upgraded probability distribution (EPRI named the new distribution as the posterior distribution or updated distribution). Then EPRI compared the sample cumulative hazard function against Hydro One's cumulative hazard function and the results are presented in Figure 9.2[114] below:[115]

Figure 9.2 Comparison of Model and Sample Cumulative Hazard Functions 115kV Transformers



Hydro One confirmed that the cumulative hazard function derived from its removal data is represented by the black line in the figure and the cumulative hazard function derived from EPRI's sample data is represented by the red lines.[116]

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[114] Exhibit B-1-1, TSP Section 1.4, filed 2019-06-19, Attachment 2, page 26 of 78.

[115] Exhibit B-1-1, TSP Section 1.4, filed 2019-06-19, Attachment 2, pp. 24-27 of 78.

[116] Oral Hearing Transcript, Volume 2 Revised, page 132.

Figure 9.2 shows a good fit between the sample data and Hydro One's data for younger transformers (Region 1). However, for older transformers (Region 2), Hydro One's data (black line) result in a steeper replacement rate than EPRI's sample data (red lines).[117]

When asked how Hydro One justifies the higher probability of replacement shown in Region 2, Hydro One indicated that its operation would be much more in line with the red line if its operation was run to failure.[118] This statement implies that red lines represent a running to failure scenario. OEB staff submits that this is unlikely the case. As noted above, red lines are derived from EPRI's sample data of a number of utilities' in-service and failures datasets. If red lines represent running to failure, it means that run to failure is the main category of replacement among the sample utilities. OEB staff does not know details about EPRI's sample utilities' practices regarding assessment and replacement of transformers. However, a survey conducted by EPRI concluded that "targeted replacement based upon assessment of transformers utilizing test and inspection data" accounts for 54.8% of transformers replacements among utilities that participated in the survey. In addition, run to failure only represents 21.3% of transformer replacements for those utilities in the survey.[119] Because the highest percentage of transformer replacements falls into the assessment and inspection category, OEB staff submits that red lines provide reasonable probabilities of removal for the sample utilities that conduct condition-based transformers replacements. Therefore, OEB staff submits that Figure 9.2 shows that Hydro One replaces older transformers at a quicker rate than expected from EPRI's model using the sample utilities' data.

OEB staff submits that the issue of replacing older assets at a quicker rate than expected also exists for circuit breakers.[120] Hydro One explained that the reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report (e.g. station decommissioning and reconfiguration requests from customers).[121] However, Hydro One did not analyze the impacts of these identified reasons and OEB staff cannot tell how much Hydro One's curve would move towards EPRI's curve when these factors are excluded.

[117] Exhibit B-1-1, TSP Section 1.4, filed 2019-06-19, Attachment 2, page 26 of 78.
[118] Oral Hearing Transcript, Volume 2 Revised, page 135.
[119] Exhibit B-1-1, TSP Section 1.4, Attachment 6, filed 2019-06-19, page 57 of 98.
[120] Exhibit B-1-1, TSP Section 1.4, Attachment 3, filed 2019-06-19, page 25 of 155.
[121] Exhibit B-1-1, TSP Section 3.2, filed 2019-06-19, pp. 13-14 of 28.

OEB staff understands that Hydro One relies on condition assessments when making replacement decisions and replaced assets are deemed to be end of life.[122] However, Hydro One confirmed that it does not track reasons for removal in its dataset, therefore, failures and discretionary replacements cannot be distinguished by EPRI.[123] OEB staff submits that because Hydro One does not track reasons for removal, neither EPRI nor OEB staff can tell whether Hydro One's deemed condition-based failure is aligned with industry best practice. Hydro One acknowledged that the issue of deemed failure has always been contentious.[124]

> MS. JABLONSKY: The data that was provided was removed from service. If we -- from time to time we do get into -- and I think also with EPRI as well -- we do get into the issue as to what is deemed a failure. Is a failure a class 1 failure where we have a Minden, where we have a large fire on the 401, or is the failure on -- is the failure considered to be removing it three days before it actually failed? Is that removal from service? Or is that a failure? So that has always been in contention.
>
> So if when we look at how would we categorize or remove or removal from service, that has always been the knife's edge, I guess.

Hydro One also stated that Region 2 (older assets) was not used to project asset replacements because EPRI cannot determine the reasons for removal for older assets based on the information provided by Hydro One.[125] Region 1 (younger assets) was the only area that was used by EPRI for a projection.[126] OEB staff submits that EPRI's projection based on Region 1 data is not much more than a mathematical representation of Hydro One's historic removal decisions. The projection estimates the age at which

[122] Oral Hearing Transcript, Volume 2 Revised, page 137.
[123] Oral Hearing Transcript, Volume 2 Revised, page 134.
[124] Oral Hearing Transcript, Volume 2 Revised, pp. 133-134.
[125] Oral Hearing Transcript, Volume 2 Revised, page 133.
[126] Oral Hearing Transcript, Volume 2 Revised, page 135.

Hydro One is likely to replace the asset, rather than providing a representation of the deteriorating performance of the asset.

Repair vs. Replace Evaluation

For high-value assets, such as transformers, Hydro One's subject matter experts perform asset condition assessments as well as "repair vs. replace" evaluations. Subject matter experts also prepare transformer assessment reports that are used to justify investment decisions.[127]

OEB staff reviewed an example of a power transformer assessment report and understands that net present value (NPV) analysis was conducted to evaluate the cost benefit for various asset management options (Status Quo Maintain, Repair, and Replace). OEB staff noted that Hydro One assumes that the asset would be replaced at economic end of life (i.e. 2021) under both the Status Quo Maintain and the Repair scenarios.[128] This assumption demonstrates that Hydro One assumes that refurbishment of an asset will not extend its operating life. Hydro One confirmed that under both scenarios, there would not be a difference as to when the replacement would happen.[129] OEB staff submits that Hydro One's NPV analysis will likely conclude that it is more economical to replace the asset rather than to repair it since the Repair scenario includes additional costs without any benefit of incremental economic life. OEB staff submits that Hydro One did not provide evidence to confirm that refurbishment of the asset will not extend its operating life beyond the deemed economic end of life.

Conductor Replacements

Drivers for the Replacements

Hydro One indicated that the primary drivers for the planned conductor replacements are safety and reliability.[130]

> MR. JESUS: So from a lines point of view, as I indicated previously, we had 792 delivery points that were interrupted. One percent of them were caused by conductors.

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[127] Exhibit B-1-1, TSP Section 2.1, filed 2019-06-19, page 16 of 54.
[128] Exhibit I-1-OEB-19, Attachment 1, filed 2019-08-02, page 14 of 23.
[129] Technical Conference Transcript, Volume 1 Revised, page 11.
[130] Oral Hearing Transcript, Volume 2 Revised, page 116.

> But I have to reiterate, this is not a performance issue here. This is a safety issue that we're dealing with. The conductors are at end of life. They have exhausted their life. From an engineering standard point of view, they are less than 85 percent tensile strength, less than four torsions.
>
> So we can talk, we can talk reliability, but that's not the driver here. The driver is, from a safety point of view, they have exhausted their life.

When asked later in the oral hearing to confirm the accuracy of the statements above, Hydro One responded that:[131]

> MR. JESUS: I do, I recall that comment. But I would also add that safety is definitely one of the primary considerations, but reliability obviously will begin to deteriorate as those assets continue to age.
>
> So again, safety is the dominant reliability -- the dominant factor for replacement, condition, based on condition of those conductors.
>
> But obviously reliability will begin to deteriorate, as it is a lagging indicator. So eventually, we will begin to see the reliability performance of those 100-year old conductors.

Hydro One's conductor replacement proposal is based upon tests of the physical strength of the conductor. The condition assessment rating is principally derived from

[131] Oral Hearing Transcript, Volume 3 Revised, page 18.

tests of the conductor's tensile and ductile strength.[132] The conductor's tensile and ductile strength allow it to withstand forces, such as gravity, wind or ice accumulation.

No evidence was provided demonstrating that conductor wires commonly fail prior to the failure of other transmission elements (including splices, dead-ends, hardware, insulators and structures) under expected weather conditions including extreme ice, snow and wind loads, or that their electrical conducting performance deteriorates in accordance with the assessed condition.

Hydro One stated that although conductor replacement cannot simply be reviewed from a performance point of view,[133] reliability will deteriorate.[134] However, Hydro One has not demonstrated that the conductors to be replaced are no longer able to perform the service for which they were designed (i.e. conducting electricity). OEB staff submits that Hydro One's conductor replacement proposal is based upon the asset testing results rather than the actual asset performance. Hydro One has not demonstrated a correlation between its conductor condition assessment testing and its historical conductor performance deterioration, nor has Hydro One shown that it faces a materially increased risk of physical conductor failure (i.e. wire breakage between splices) under expected operating conditions during the forecast period.

Cost and Benefit

OEB staff notes that Hydro One does not differentiate between conductor wire versus splice failures when categorizing "conductor system" failures, as such, Hydro One does not know what proportion of its conductor system failures are related to splice failures rather than conductor wire failures.[135] This is an important economic consideration because Hydro One has indicated that replacing all the conductor wire between two splices costs approximately 20 times more than simply replacing a poor condition splice.[136]

Furthermore, OEB staff notes that Hydro One has not demonstrated in its evidence that the planned conductor replacements will meaningfully improve system reliability, for two reasons:

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[132] Oral Hearing Transcript, Volume 2 Revised, page 101. Oral Hearing Transcript, Volume 3 Revised, page 19. Oral Hearing Transcript, Volume 2 Revised, page 7.
[133] Oral Hearing Transcript, Volume 2 Revised, pp. 115-116.
[134] Oral Hearing Transcript, Volume 3 Revised, page 18.
[135] Oral Hearing Transcript, Volume 2 Revised, page 102.
[136] Exhibit I-1-119, filed 2019-08-02, page 1 of 1.

i. The number of outages caused by the conductors targeted for replacement is a very small number relative to Hydro One's total annual outages; and
ii. For the transmission line segments where conductors are targeted for replacement over the forecast period, Hydro One has not demonstrated that past customer delivery point interruptions would have been avoided had the conductors been in brand new condition

When asked what percentage of customer delivery point interruptions are caused by condition-related conductor failures, Hydro One responded that approximately 1% of delivery point interruptions are due to conductor failures.[137]

Hydro One stated that between 2008 and 2018, 36 of 126 total delivery point interruptions occurred on the 1903 circuit-km of the aluminum conductor steel reinforced (ACSR) type of conductor that Hydro One proposed to replace.[138] These delivery point interruptions suggest that approximately 30% (36 divided by 126 = 28.6%) of the outages experienced over a ten year period related to the line segments being targeted for conductor replacement.

Therefore, the replacement of the 1903 circuit-km ACSR conductors will potentially address 0.3% (30% of 1%) of annual customer deliver point interruptions. OEB staff submits that this figure is a very small proportion of Hydro One's expected annual outages and is unlikely to have a meaningful impact upon Hydro One reliability performance results.

Last but not least, OEB staff submits that Hydro One's proposed expenditures on conductor replacements are not cost effective, as measured on a dollar spent per avoided customer interruption ($/ACI) basis, relative to other investments. Using the proposed expenditures on ACSR conductors (SR-19 and SR-20), Hydro One proposed to spend $535.7 million over the 2020-2022 period,[139] in order to address an issue that represents 0.3% of Hydro One's annual delivery point interruptions. From a cost efficiency point of view, Hydro One has not shown that this program compares favorably to other reliability driven programs. For example, Hydro One provided presentation materials from the Boston Consulting Group (BCG). The presentation included analysis of how different vegetation management programs contributed to improved reliability and

[137] Oral Hearing Transcript, Volume 2 Revised, page 116.
[138] Exhibit I-1-23, filed 2019-08-02, page 3 of 3.
[139]Exhibit 1-1-1, TSP Section 2.3, filed 2019-06-19, Table 6, page 15 of 20.

how the alternative programs compared to one another on a dollar per avoided customer interruption basis. It appears BCG provided Hydro One advice on how to best structure their vegetation management programs to maximize reliability improvement per dollar spent, in part by referencing the $/ACI metric, where $/ACI represents avoided customer outages.[140] Hydro One did not present any evidence comparing reliability improvements expected for the conductor replacement projects versus other capital expenditure programs.

In summary, OEB staff submits that the issues identified above should be taken into consideration when making decisions on the proposed capital expenditures.

Customer Engagement

Customer Priorities

Hydro One undertook a broad range of customer engagement activities including a transmission customer engagement survey. Hydro One stated that the feedback obtained through engagement activities provides an important and direct input into its investment planning process, which results in an investment plan that is closely aligned with and highly responsive to customer needs and preferences. Customer priority outcomes identified from the survey include safety, reliability and outage restoration. Hydro One incorporated these priorities into its planning framework by aligning its risk-based scoring criteria for investment candidates to closely reflect customer priorities.[141]

OEB staff acknowledges that Hydro One has improved its transmission customer engagement compared to the last application, including undertaking the survey prior to the beginning of the investment planning process.[142] However, OEB staff identified concerns regarding the design of the survey. Specifically, OEB staff observed that in the survey carried out by IRG for Hydro One, IRG asked customers to rate the importance of the seven outcomes: customer service, environmental stewardship, outage restoration, power quality, productivity, reliability, safety.[143] Hydro One confirmed that cost did not come up as one of the priorities for customers because cost was not included in the list for customers to rank.[144] When IRG asked customers "Are there any outcomes we

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[140] Exhibit JT 1.11, Attachments 1, filed 2019-08-28, pp. 1-18.
[141] Argument in Chief, filed 2019-11-22, pp. 59-60.
[142] Argument in Chief, filed 2019-11-22, page 58.
[143] Exhibit B-1-1, Section 1.3, Attachment 1, filed 2019-06-19, page 101 of 144.
[144] Exhibit I-1-39, filed 2019-08-02, page 3 of 4.

missed?" cost was identified as the missing outcome by local distribution companies, end users, and generators.[145]

OEB staff understands that cost was captured later in the survey,[146] however, the way the survey was designed forced customers to rank a predetermined list of outcomes chosen by Hydro One.[147] OEB staff submits that if cost had been included in the list, the ranking of customers' priorities would be different. As such, OEB staff submits that the OEB should not place significant weight on the outcomes reported by Hydro One as compelling evidence of customers' support for the proposed level of capital expenditures. OEB staff notes that Hydro One has expressed its willingness to add cost to the list of outcomes in a future survey.[148]

Risk Reliability Model

The risk reliability model (RRM) was used by Hydro One to provide a directional indicator to customers and stakeholders to communicate reliability risk. RRM is not used to identify asset needs or justify investments.[149] In its decision on Hydro One's 2017-2018 transmission revenue requirements application, the OEB found that it is impossible to determine from the model whether a certain reduction in reliability risk is worth a certain level of capital investment. The OEB concluded that RRM needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability.[150] OEB staff notes that the customer engagement process was conducted in advance of the decision. Hydro One confirmed that the OEB's concerns regarding the RRM remains to be addressed in a future customer engagement process.[151]

In summary, OEB staff is not convinced that outcomes from the customer engagement process sufficiently support the proposed level of capital expenditures.

[145] Exhibit B-1-1, Section 1.3, Attachment 1, filed 2019-06-19, pp. 72-73 of 144.
[146] Oral Hearing Transcript, Volume 7 Revised, page 14.
[147] Oral Hearing Transcript, Volume 7 Revised, page 3.
[148] Oral Hearing Transcript, Volume 7 Revised, page 20.
[149] Exhibit B-1-1, TSP Section 1.3, Attachment 4, filed 2019-06-19, page 1 of 2.
[150] EB-2016-0160, Decision and Order, revised October 11, 2017, page 24.
[151] Oral Hearing Transcript, Volume 7 Revised, page 28.

Capital Expenditures

System Renewal

System Renewal expenditures comprise the bulk of Hydro One's planned investments, representing close to 83.3% of capital expenditures over the planning period. Hydro One proposed an average annual increase of approximately 15.2% for system renewal projects over the 2020-2022 period .[152] These expenditures are mainly driven by plans to replace assets that are near or at the end of their lives. Such projects include transmission line refurbishment, station reinvestments, transformer replacements, and air blast circuit breaker replacements.[153]

The TSP delivers an increased emphasis on line renewal investments at a cost of approximately $2.0 billion over the planning period, of which $1.2 billion is required over the 2020-2022 test period, to refurbish and replace end of life transmission lines, underground cables, insulators and wood poles.[154]

Table 10 below summarizes the historical capital expenditures on system renewal over 2015-2019 and the proposed spending for 2020.[155]

[152] Exhibit J1.1, filed 2019-10-22, Table 6, page 6 of 10.

[153] Exhibit B-1-1, TSP Section 3.1, filed 2019-06-19, pp. 5-8 of 24.

[154] Exhibit A-3-1, filed 2019-06-19, page 36 of 50.

[155] Exhibit B-1-2, filed 2019-06-19, Appendix 2-AA, Capital Projects Table.

Table 10
Capital Expenditures on System Renewal ($ Million)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Circuit Breakers	7.1	4.1	0.4	0.1	0.0	4.1
Transmission Lines	125.4	164	197.2	221.2	291.9	323.9
Integrated Station	374.2	469.1	481.0	410.7	336.9	405.1
Underground Lines & Cable	3.5	1.7	10.7	16.5	15.0	7.1
Power Transformers	43.5	13.0	0.0	-0.7	0.1	0.0
Other Power Equipment	12.5	5.3	0.0	0.3	0.0	0.0
Protection and Automation	60.2	40.5	20.9	44.4	72.8	77.7
Ancillary System and Site Facilities	35.3	11.7	3.7	1.0	0.0	0.0
Transformers Demand and Spares	27.2	24.6	26.8	82.6	56.6	47.4
Total	**688.9**	**733.9**	**740.7**	**776.2**	**773.3**	**865.2**

OEB staff notes that for the 2020 rate year, approximately 46.8% of the proposed expenditures are driven by investments on integrated stations. Following that, investment on transmission lines accounts for about 37.4% of the budget. OEB staff notes that the proposed expenditures on transmission lines of $323.9 million for 2020 represents an 83.0% increase over the average annual spending of $177.0 million over 2015 to 2018.

OEB staff identified issues with respect to Hydro One’s capital planning process above. OEB staff submits that most of the issues, including Hydro One’s rate of removal, repair vs. replace evaluation, and conductor replacements affect the proposed capital expenditures on system renewal. The evidence as filed did not allow OEB staff to quantify impacts of identified issues on the proposed capital expenditures. For example, Hydro One does not track reasons for asset removal such that OEB staff cannot verify the non-failure replacements and quantify the impacts. For the preceding reasons, OEB staff submits that a reduction is necessary and suggests a reduction of $318.5 million (10.1%) to the total 2020-2022 capital expenditures on system renewal.

System Service

System service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. These investments account for about 13.3% of total capital expenditures over the planning period.[156]

Table 11 below summarizes the historical capital expenditures on system service over 2015-2019 and the proposed spending for 2020.[157]

Table 11
Capital Expenditures on System Service ($ Million)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Inter Area Network Transfer Capability	86.3	80.8	36.0	48.9	54.9	121.0
Local Area Supply Adequacy	64.9	54.3	45.1	20.7	39.0	73.9
Smart Grid	3.5	3.3	0.7	0.2	0.0	0.0
TS Upgrades to Facilities Distribution Generation	-1.2	0.0	0.0	0.0	0.0	0.0
Performance Enhancement	1.3	0.4	0.0	0.0	0.3	0.3
Risk Mitigation	3.1	1.8	9.5	2.6	5.4	4.7
Power Quality	0.0	0.2	2.3	1.4	4.1	4.2
Total	**157.9**	**140.9**	**93.5**	**73.9**	**103.8**	**204.1**

Kapuskasing Area Reinforcement (KAR) Project

The KAR project was approved by the OEB in a leave to construct (LTC) proceeding. By a letter dated March 18, 2019, Hydro One informed the OEB of a change in the in-service date and cost of the KAR project. The overall project cost increased from $21.07 million

[156] Exhibit B-1-1, TSP Section 3.1, filed 2019-06-19, page 19 of 24.
[157] Exhibit B-1-2, filed 2019-06-19, Appendix 2-AA, Capital Projects Table.

($15.07 million in lines cost and $6 million in station cost) to $32.1 million ($14.8 million in lines cost and $17.3 million in station costs). The station cost component of the project increased from the original estimate of $6 million to an updated estimate of $17.3 million.[158] Hydro One explained that the initial estimate of the station component documented in the LTC application was preliminary by nature and made no reference to an Association for the Advancement of Cost Engineering (AACE) or accuracy range.[159] Hydro One noted that the reason the LTC application was filed with the station component being preliminary was to meet the project's timelines requested by the IESO.[160] Hydro One stated that site specific conditions led to the increased budget, including the relocation of the existing low voltage capacitor bank and extension of the control building.[161]

Hydro One stated in this proceeding that the original cost estimate was at AACE Class 4 and the updated estimate is at AACE Class 3.[162] When asked what contingency was included in the original cost estimate, Hydro One stated that it had not done a full bottom-up risk review that is probabilistically modelled into contingency.[163] Hydro One stated in its LTC application that the original cost was prepared at a budgetary estimating phase,[164] but it did not mention the accuracy of the cost estimate. OEB staff notes that in the original budget, $0.7 million of contingency was included in the line component, and no contingency was specifically noted in the estimate for the station component.[165] Without any indication of the accuracy of the estimate in the LTC application, and given the inclusion of contingency in the estimate, it was not clear in the LTC proceeding that the costs were preliminary. Hydro One could have highlighted in the LTC proceeding that the estimate was based on an early stage of engineering and design and proposed specific treatment to deal with the preliminary nature of the estimate, but it did not.

OEB staff understands that the IESO confirmed that the KAR project remains the recommended solution for meeting reliability in the Kapuskasing area based on its review of transmission and generation options. The IESO concluded that the KAR project is expected to be the least cost solution, and so the project should proceed to be

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158 EB-2018-0098, Hydro One's letter dated March 18, 2019.
159 Exhibit I-1-136, filed 2019-08-02, page 3 of 4.
160 Oral Hearing Transcript, Volume 3 Revised, page 42.
161 EB-2018-0098, Hydro One's letter dated March 18, 2019.
162 Oral Hearing Transcript, Volume 3 Revised, page 44.
163 *Ibid.*
164 EB-2018-0098, file 2018-02-05, Exhibit B-03-01, page 2 of 2.
165 EB-2018-0098, file 2018-02-05, Exhibit B-07-01, page 1 of 4.

implemented despite the change in the cost of the KAR project.[166] The evidence as filed by Hydro One, however, does not demonstrate whether Hydro One tried to address the changes in project scope in as cost effective a way as possible, in order to ensure that the updated budget would be as close to the original one as possible.

The proposed capital expenditures on the KAR project is shown in Table 12[167] below.

Table 12
Capital Expenditures on the KAR Project ($ Million)

	2020	2021	2022
Net Investment Cost	6.7	3.8	0.0

OEB staff submits that considering the accuracy level of the original cost estimate was not highlighted in the LTC application and no evidence regarding budgetary control has been presented, the cost increase should not be borne entirely by ratepayers. OEB staff suggests that the cost increase be split between Hydro One and ratepayers. Accordingly, OEB staff submits that a disallowance of $5.7 million is necessary.

OEB staff suggests that in the next rebasing application, for all investments requiring leave to construct approvals, Hydro One should provide comparisons of those projects between what was filed in the LTC applications and what was budgeted into capital expenditures for the test years, and provide explanations of any material variances regarding scope, cost or schedule.

<u>System Access</u>

System access investments are driven by new load and generation customer connections, and transmission asset modifications to accommodate third party requests. These investments account for about 1.0% of total capital expenditures over the planning period.[168]

[166] EB-2019-0134, filed May 8, 2019, pp. 2-3.
[167] Exhibit B, part 4, filed 2019-06-19, ISD: SS-10, page 3 of 6.
[168] Exhibit B-1-1, TSP Section 3.1, filed 2019-06-19, page 17 of 24.

Table 13 below summarizes the historical capital expenditures on system access over 2015-2019 and the proposed spending for 2020.[169]

Table 13
Capital Expenditures on System Access ($ Million)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Transmission Lines	-0.5	1.8	-0.9	4.4	2.9	0.9
Generator Customer Connection	-1.7	0.2	0.4	0.3	1.1	2.3
Load Customer Connection	7.7	13.6	42.3	28.5	41.1	21.6
P&C Enablement for Generation Connections	2.1	1.3	0.8	0.5	0.0	0.0
Total	**7.6**	**17.0**	**42.7**	**33.7**	**45.1**	**24.8**

OEB staff has no objection to Hydro One's proposed capital expenditures on system access projects.

General Plant

General Plant expenditures are not part of the TSP but are required to support the performance of Hydro One's core business and operational functions. These investments account for about 6.8% of total capital expenditures over the planning period.[170]

Table 14 below summarizes the historical capital expenditures on General Plant over the 2015-2019 period and the proposed spending for 2020:[171]

[169] Exhibit B-1-2, filed 2019-06-19, Appendix 2-AA, Capital Projects Table.
[170] Exhibit B-1-1, TSP Section 3.1, filed 2019-06-19, page 17 of 24.
[171] Exhibit B-1-2, filed 2019-06-19, Appendix 2-AA, Capital Projects Table.

Table 14
Capital Expenditures on General Plant ($ Million)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Facilities & Real Estate	22.7	13.9	6.7	7.0	7.2	8.1
Grid Operating and Control Facilities	14.2	7.6	6.0	3.8	37.4	35.3
Information Technology	21.6	35.9	32.8	42.0	33.7	25.7
Operating Infrastructure	1.4	4.6	4.8	5.8	10.2	21.1
Other (including CDM)	0.7	0.3	-1.1	-0.7	0.0	0.0
Site Facilities and Infrastructure	5.9	8.1	10.8	16.4	12.0	9.4
Transport and Work & Service Equipment	22.1	24.6	16.9	9.3	15.9	15.8
Total	**88.6**	**94.8**	**76.9**	**83.6**	**116.3**	**115.4**

Integrated System Operating Centre (ISOC)

The ISOC project began in 2015 and will be in service in 2021 to be used as the primary operating control center.[172]

The capital investment on ISOC increased from $138.4 million, as filed in Hydro One's 2018-2022 distribution Custom IR application,[173] to $154.4 million as included in this application. This represents approximately a 12% increase in the estimated cost. Hydro One listed reasons for the cost increase as being: skilled trade labour rate escalations, new foreign tariff structures, and competition for local construction resources.[174]

[172] Exhibit B, part 4, filed 2019-06-19, ISD: GP-01, page 1 of 33.
[173] EB-2017-0049
[174] Exhibit I-7-38, filed 2019-08-02, page 1 of 2.

The proposed capital expenditures on the ISOC project is shown in Table 15 below:[175]

Table 15
Capital Expenditures on the ISOC Project ($ Million)

	2020	2021	2022
Net Investment Cost	32.4	12.7	0.0

OEB staff notes that the $138.4 million was a Class A cost estimate with the highest range of accuracy of +/-5%. However, the updated estimate of $154.4 million represents an increase of approximately 12%, which is well above the accuracy range of +/-5%.

OEB staff submits that the magnitude of this increase relative to the stated range of accuracy raises concerns about the reliability of the updated cost estimate. OEB staff accordingly submits that a disallowance of $4.5 million, or roughly 10% of the forecast cost of the project should be made by the OEB to provide Hydro One with an incentive to avoid further unanticipated cost increases in this project.

Capital Plan Execution

In its decision on Hydro One’s 2017-2018 transmission revenue requirement application, the OEB found a historic variance between proposed and actual capital spending, particularly in sustaining capital, as well as the consistent over-forecasting of in-service capital additions for nine consecutive years from 2007 to 2015 by an average of 14.6%.[176] The OEB directed Hydro One to provide a report detailing its overall performance in the execution of the capital plan compared to the approved plan.[177] Specifically, the OEB requested a report showing the status of major projects or programs with total budgeted cost greater than $3 million.

In this application, Hydro One filed a capital program performance report.[178] Hydro One has demonstrated its ability to successfully track and perform large capital work plans by

[175] Exhibit B, part 4, filed 2019-06-19, ISD: GP-01, page 15 of 33.
[176] EB-2016-0160, Decision and Order, Revised October 11, 2017, pp. 17-18.
[177] EB-2016-0160, Decision and Order, Revised October 11, 2017, page 117.
[178] Exhibit C-2-1, Attachment 1, filed 2019-06-19.

delivering its 2017 and 2018 investment plan on an envelope basis within 1.5% of OEB-approved capital expenditure levels and 0.7% of OEB-approved in-service additions.[179]

OEB staff notes that Hydro One took actions to improve its capital plan execution, including reviewing and streamlining its capital delivery process, establishing a Redirection Committee, and improving estimating and scheduling tools and processes.[180]

OEB staff submits that Hydro One has excelled in its capital plan execution and demonstrated its ability to deliver capital projects based on the OEB approved amounts.

10. *Are the methodologies used to allocate Common Corporate capital expenditures to the transmission business and to determine the transmission Overhead Capitalization Rate appropriate?*

Background

Although this section primarily addresses the allocation of common corporate OM&A to Hydro One's transmission business, OEB staff will also briefly touch on the allocation of common corporate capital expenditures and the allocation of shared assets to Hydro One's transmission business. In addition, OEB staff will also briefly discuss overhead capitalization rates.

Hydro One filed three Black and Veatch (B&V) reports in this proceeding, as follows:

1) Review of Allocation of Common Corporate Costs (Transmission) – 2019 Black & Veatch Project No. 188588.[181]
2) Review of Shared Assets Allocation (Transmission) -2019 Black & Veatch Project No. 188588.[182]
3) Review of Overhead Capitalization Rates (Transmission) – 2019 Black & Veatch Project No. 188588.[183]

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[179] Argument in Chief, filed 2019-11-22, page 69.
[180] Argument in Chief, filed 2019-11-22, page 70.
[181] Exhibit F, Tab 2, Schedule 6, Attachment 1
[182] Exhibit C, Tab 3, Schedule 1, Attachment 1
[183] Exhibit C, Tab 8, Schedule 2, Attachment 1

The three B&V reports were issued on January 31, 2019. Hydro One indicated[184] that the Ontario provincial government's Bill 2 (i.e. Schedule 1 of Bill 2 is the *Hydro One Accountability Act, 2018*[185] or HOAA) was addressed in the first and third of the above noted reports, and not required for the second report. However, OEB staff notes that due to the timing of issuance of the B&V reports, the February 21, 2019 Directive (the Directive)[186] and any findings from the March 7, 2019 Hydro One Distribution decision and order[187] were not addressed in the B&V reports.[188]

Hydro One also noted that the B&V methodology is materially consistent with that of prior applications.[189] Hydro One stated[190] that there are no key recommendations to be implemented comparing the three B&V studies and the prior studies from previous applications. Hydro One further stated that there have been no material differences between the studies and B&V believe that the current methodology continues to be appropriate for Hydro One.

Allocation of Common Corporate Costs and Shared Assets Background

Hydro One is requesting a 2020 Common Corporate Costs and Other Costs OM&A of $30.3 million[191] for its transmission business. Hydro One stated[192] that Common Corporate OM&A costs are allocated to its distribution and transmission businesses and to each unregulated segment based on shared functions and services provided and an established cost allocation approach based on the cost causality principle.

Hydro One further stated[193] that it uses a centralized shared services model to deliver common services to its transmission and distribution businesses, as well as to its

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[184] Exhibit I, Tab 01, Schedule 143 (OEB Staff Interrogatory #143)
[185] *The Urgent Priorities Act, 2018*
[186] At Exhibit F, Tab 4, Schedule 1, Page 35, Hydro One described the Ontario Government Directive that was issued on February 21, 2019. Hydro One stated that the government set out certain compensation-related requirements for the Chief Executive Officer, other executives and Board of Directors of Hydro One Limited and its subsidiaries, which Hydro One must follow when developing its Board and Executive compensation framework as set out in the HOAA.
[187] EB-2017-0049
[188] Exhibit I, Tab 01, Schedule 193 (OEB Staff Interrogatory #193)
[189] Exhibit I, Tab 01, Schedule 193 (OEB Staff Interrogatory #193)
[190] Exhibit I, Tab 01, Schedule 143 (OEB Staff Interrogatory #143)
[191] Exhibit F, Tab 1, Schedule 1, Page 3 Table 1
[192] Exhibit F, Tab 2, Schedule 1, Page 1
[193] Exhibit F, Tab 2, Schedule 1, Page 3

affiliated companies. Hydro One noted that the centralized shared services model is an effective and widely used method of delivering common corporate services to multiple subsidiaries and/or multiple business units. Hydro One noted that since 2009 it has been applying this cost allocation methodology developed by B&V.

OEB staff notes that in the March 7, 2019 Hydro One Distribution decision and order, the OEB determined[194] that the allocation methodology of common corporate costs, developed by B&V, and approved by the OEB in Hydro One's previous Transmission rate proceeding, is acceptable for the plan term. The OEB stated that it expects this issue to be examined in detail when Hydro One files a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

Overhead Capitalization Rate Background

Hydro One provided[195] the following table showing its proposed overhead capitalization rates and amounts.

Table 16 – Overhead Capitalization Rates and Amounts

Overhead Cost Category	Bridge (%)	Test Years (%)			Bridge ($ millions)	Test Years ($ millions)		
	2019	2020	2021	2022	2019	2020	2021	2022
Capitalized Administrative & General Costs[1]	9%	8%	8%	8%	91.3	96.6	99.3	100.1
Capitalized Planning, Customer and Operating Costs[2]	2%	2%	2%	2%	22.9	22.8	23.2	23.7
Total	11%	10%	10%	9%	114.1	119.4	122.6	123.8

[1] *Administrative & General Costs include all common corporate functions and services costs*

[2] *Operating costs include asset management, network operating and customer care management costs*

Hydro One concluded[196] that its overhead and indirect cost capitalization methodology, as reviewed by B&V and previously approved by the OEB, is consistent with: (a) legacy Canadian and existing USGAAP; and (b) regulatory principles.

[194] EB-2017-0049 Decision and Order, March 7, 2019, page 79, 119

[195] Exhibit C, Tab 8, Schedule 2, Page 2, Table 1

[196] Exhibit C, Tab 8, Schedule 2, Page 2 & 3

Hydro One also stated[197] that:

- The capitalization rate is decreasing due to the methodology; as it is specifically affected by the ratio of corporate costs (slight increase) to capital spend (larger increase)
- The overhead capitalized costs in this proceeding are lower by approximately $16 million when comparing 2020 to the previously filed 2018 capitalization amount which is mainly due to a reduction in overall corporate overheads[198]

Hydro One noted[199] that this B&V study was first conducted for 2006 transmission rates. Hydro One confirmed that in this application B&V did not look specifically at USGAAP policy relative to rate-regulated accounting and no assessment was made.

Hydro One noted[200] that in its prior transmission decision,[201] the OEB indicated that it will consider whether it should initiate a policy review regarding whether it is appropriate to allow for the continued use of USGAAP for the purpose of determining the capitalization of overhead amounts. Hydro One further stated that in its prior distribution decision,[202] the OEB stated that it expects to review Hydro One's approach to capitalization in its next rebasing application. Hydro One stated that the OEB's expectation is that Hydro One will provide a report comparing its capitalization of common corporate costs with those of other utilities. Given the OEB's directions on this issue, Hydro One submitted that the proposed methodology for determining the transmission overhead capitalized in the current application is appropriate and should be approved.

OEB Staff Submission

OEB staff submits that Hydro One's 2020 Common Corporate Costs and Other Costs OM&A request of $30.3 million[203] for its transmission business is reasonable. OEB staff takes no issue with this amount, as it is largely driven by a cost allocation methodology that has been in place since 2009, as developed by B&V.

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[197] Exhibit I, Tab 01, Schedule 139 (OEB Staff Interrogatory #139)
[198] Exhibit F, Tab 2, Schedule 1
[199] Oral Hearing Transcript October 29, 2019, page 117-118
[200] Argument in Chief Page 73
[201] EB-2016-0160
[202] EB-2017-0049
[203] Exhibit F, Tab 1, Schedule 1, Page 3 Table 1

As the B&V allocation methodology of common corporate costs will be reviewed in detail in a future proceeding,[204] OEB staff also submits that it is more appropriate to test this methodology at that future time. OEB staff submits that the OEB should order in this proceeding that a detailed review of Hydro One's shared assets allocation methodology should occur at the time of Hydro One's combined 2023 and subsequent years application, to be consistent with the OEB's treatment of the allocation methodology of common corporate costs in the prior distribution proceeding.[205] As a result, OEB staff takes no issue with the allocation of corporate costs (capital expenditures and OM&A) and shared assets allocation to the transmission business in this proceeding.

OEB staff also has no issue with the overhead capitalized costs as they are driven primarily by an increased amounts of assets being placed in service, and not by an increase in overhead capitalized costs.

OEB staff submits that the applicable overhead capitalization B&V study should also be examined in detail in Hydro One's combined application. Hydro One stated that this study was first generated for 2006 transmission rates and also confirmed that B&V did not look specifically at USGAAP policy relative to rate-regulated accounting. OEB staff submits that such a review should also be undertaken, as accounting standards from 2006 have evolved.

OEB staff submits that the B&V methodologies should continue in this proceeding, as they have been tested and accepted in prior proceedings, and there are no material differences between the studies.

USGAAP

Background

Hydro One follows USGAAP for regulatory purposes and therefore follows a USGAAP based capitalization policy. Under USGAAP, Hydro One has the ability to capitalize more in the form of overhead costs than they otherwise would be permitted if they had been ordered to follow the OEB's mandated Modified International Financial Reporting Standards (MIFRS) based capitalization policy. Most utilities in Ontario are required to follow this capitalization policy. A utility benefits from the ability to capitalize more

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[204] This methodology will be tested when Hydro One files a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027
[205] EB-2017-0049

because they will be entitled to earn a return on rate base associated with the capitalized cost in addition to also recovering the cost in rates through annual depreciation expense.

OEB staff raised concerns with Hydro One's continued use of a USGAAP based capitalization policy for regulatory purposes in both its last transmission and distribution rates proceedings.[206] In response to the concerns raised during the previous transmission rates proceeding the OEB indicated that it would consider whether it should initiate a policy review regarding whether it is appropriate to allow for the continued use of USGAAP for the purpose of determining the capitalization of overhead amounts.[207] Furthermore, in the last distribution rates proceeding, the OEB stated it expects to review Hydro One's approach to capitalization in its next distribution rebasing application. To facilitate such a review, the OEB indicated its expectation that Hydro One will provide a report comparing its capitalization of common corporate costs with those of other utilities in Ontario, Canada, and North America.[208]

In the current transmission rates proceeding, OEB staff asked interrogatories related to overhead capitalization under USGAAP to which Hydro One provided the following response[209]

> Given the OEB's direction on this topic, questions in respect of Hydro One's capitalization of common corporate costs should be addressed in one of the two proceedings-types noted by the OEB above, where the appropriate evidence may be prepared and submitted for consideration.

The two types of proceedings Hydro One is referring to are either the general policy review that the OEB alluded to in the previous transmission rates proceeding (described above), or in Hydro One's next combined 2023-2027 rebasing application where the OEB indicated that it expects to review Hydro One's approach to capitalization (also described above).

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[206] The last transmission rates proceeding was EB-2016-0160 and the last distribution rates proceeding was EB-2017-0049.
[207] EB-2016-0160 Decision, p. 82.
[208] Argument-in-Chief, p 73.
[209] Exhibit I, Tab 1, Schedule 140

OEB Staff Submission

OEB staff submits that the issue related to the appropriateness of Hydro One's continued use of a USGAAP based capitalization policy for regulatory purposes should be addressed in the upcoming combined 2023-2027 rates proceeding. It is an ideal proceeding to examine this issue because Hydro One will already be submitting the capitalization study that was ordered by the OEB in the last distribution rates rebasing application.

OEB staff agrees with Hydro One that in order to facilitate a proper regulatory review of this issue, Hydro One must provide detailed evidence as part of its 2023-2027 application that presents the revenue requirement impact of transitioning to an MIFRS capitalization policy for regulatory purposes, along with a detailed analysis of the regulatory risks and challenges associated with doing so.

11. *Is the proposed capitalization of other post-employment benefits (OPEB) for both Hydro One Transmission and Hydro One Distribution appropriate, and if not, what is the appropriate approach for these costs?*

Background

In March 2017, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) No. 2017-07 which amends the USGAAP standard related to the accounting for pension and other post-employment benefit (OPEB) costs. Effective January 1, 2018, the changes introduced by the ASU limit an entity's ability to capitalize these costs to assets. For regulatory reporting purposes, the change only impacts Hydro One's OPEB costs because it recovers its pension costs on a cash basis and therefore is not underpinned by accounting standards.[210]

The net periodic benefit cost of defined benefit pension and OPEB plans (pension and OPEB expense) 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 all components of the net periodic benefit cost were eligible to be capitalized. However, as a result of ASU No. 2017-07, the service cost component is now only eligible to be capitalized.

[210] Argument-in-Chief, p. 74

Hydro One's 2017-2018 transmission revenue requirement[211] approved by the OEB did not reflect the impact of the change in this accounting standard because the standard was issued after the record of that proceeding was closed. Therefore, Hydro One applied to the OEB to establish a deferral account, effective January 1, 2018, to capture the OPEB costs previously capitalized but no longer allowed to be capitalized as per ASU 2017-07[212]. In that proceeding the OEB approved the establishment of the deferral account until the effective date of Hydro One's next transmission revenue requirement.[213] In the Decision to that proceeding, the OEB explained:[214]

> The OEB finds it appropriate to approve a deferral account 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 USGAAP accounting standard.

The OEB also directed Hydro One to propose an approach for the disposition of the OPEB Cost Deferral Account in the next proceeding and suggested that it may be appropriate to amend the calculation and treatment of interest based on the approach selected.[215]

Similarly, in Hydro One's application for 2018-2022 distribution rates,[216] the OEB approved the establishment of an OPEB Cost Deferral Account for the distribution business, which is equivalent to the account established for the transmission business. The deferral account for the distribution business was also given an effective date of January 1, 2018 and the OEB instructed Hydro One to file the necessary evidence regarding the distribution OPEB Cost Deferral Account in its next transmission rebasing proceeding (being the current proceeding) so as to permit this matter to be determined for both Hydro One's transmission and distribution businesses.[217]

In the current transmission rates proceeding, Hydro One is seeking OEB approval to continue capitalizing the non-service components of OPEBs for both its transmission and distribution businesses on the basis that the continued capitalization of these costs

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[211] EB-2016-0160

[212] EB-2017-0338

[213] This was then extended to the current transmission rates proceeding in EB-2018-0130.

[214] EB-2017-0338, May 10, 2018 Decision and Order, p. 4.

[215] EB-2017-0338, June 7, 2018 Decision and Accounting Order, p. 3.

[216] EB-2017-0049

[217] EB-2017-0049 Decision, p. 170.

enables Hydro One to accurately depict the true costs of its capital assets (preferred approach).[218]

The Federal Energy Regulatory Commission (FERC) provided the rate regulated entities under its jurisdiction with the option to elect to follow the cost capitalization provisions of ASU No 2017-07, or to continue capitalizing pension and OPEB costs consist with their current pre ASU No 2017-07 practices.[219]

If Hydro One's request for continued capitalization of the OPEB costs impacted by ASU No 2017-07 is denied, then Hydro One is alternatively requesting OEB approval to permanently continue using the OPEB Cost Deferral Account for each of the transmission and distribution businesses in order to capture the impacted OPEB costs and to dispose of the balance that accumulates in each account on a twenty-year rolling balance (as opposed to periodic clearance of the accounts in future rate applications). Hydro One argues that the proposed methodology is appropriate as twenty-years is consistent with the USGAAP guidance that allows recovery of OPEB related amounts over a period not exceeding twenty-years. Moreover, Hydro One indicates that a twenty-year rolling balance disposition method would be beneficial to ratepayers as it would minimize the impact on rates. As part of its alternate proposal, Hydro One also proposes that interest improvement be recorded on the opening monthly principal balance in the account.[220]

Hydro One further contends that accounting for the impacted OPEB costs as OM&A (i.e. in the event that its preferred and alternate approaches are denied by the OEB) would be inconsistent with the previous treatment of these costs and would give rise to intergenerational inequities because current ratepayers would bear more of the costs pertaining to assets that are benefiting future generations.[221]

Potential Outcomes and Impacts

Under Hydro One's Preferred Approach:

If the OEB approves Hydro One's request to continue to capitalize the non-service cost component of its OPEBs, then Hydro One must produce an updated rate base value during the draft rate order of this proceeding in order to reflect the impact of that decision.

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[218] Argument-in-Chief, p. 75.
[219] EB-2017-0049, Exhibit JT 1.16, page 4
[220] Argument-in-Chief, p. 76.
[221] Argument-in-Chief, p. 75-76. J6.4, p. 4

Hydro One has indicated that it has removed the non-service portion of OPEBs from rate base for purposes of calculating the revenue requirement in the current transmission rates proceeding, Therefore, the current revenue requirement as calculated would need to be updated to reflect the revenue requirement impact associated with the actual 2018, plus the forecast 2019 and 2020 capitalization of the non-service cost component of Hydro One's OPEBs. However, Hydro One has confirmed that the capital expenditure amounts included in the current transmission rates proceeding are based on the assumption that Hydro One will be permitted to capitalize the non-service component of its OPEBs (and therefore include the non-service component of OPEBs in capital project and program cost amounts).[222] As such, no adjustment with respect to the capital expenditures presented in this application would be necessary.

In respect of the distribution business, as the 2018, 2019, and 2020 distribution revenue requirement amounts as approved in the 2018-2022 distribution rates proceeding do not include the revenue requirement impact associated with the OPEB component of non-service costs, an adjustment would have to be made to calculate the new revenue requirement during an annual update for 2021 distribution rates so as to include the OPEB costs captured in the OPEB Cost Deferral Account. Through such adjustment, Hydro One would expect to be able to recover the revenue requirement associated with amounts for 2018, 2019 and 2020, which it did not collect when deriving its 2018, 2019 and 2020 revenue requirement. Moreover, capital expenditures for 2021 and 2022 would have to be adjusted to include the OPEB costs which were previously excluded.[223]

Under Hydro One's Alternate Approach:

If Hydro One's alternate proposal to continue using the OPEB Cost Deferral account and dispose of the accumulated amount on a twenty-year rolling balance is approved, then the 2020-2022 revenue requirement will be impacted by the recognition of annual amortization that is calculated on the balance in the OPEB Cost Deferral Account as at December 31, 2018.[224] The current deferral account disposition request does not contemplate this scenario and therefore Hydro One would be required to adjust its deferral and variance account disposition request during the draft rate order of this proceeding in order to reflect the impact of such a decision. Also as noted above, Hydro

[222] Exhibit F, Tab 5, Schedule 1, p. 10.

[223] J6.4, p. 4

[224] Hydro One has not explicitly discussed how the transmission revenue requirement is impacted if the OEB approves its alternate methodology. However OEB staff believes that the impact to this transmission rates application would be limited to the recognition of amortization associated with the balance of the OPEB Cost Deferral Account at December 31, 2018. The balance in the OPEB Cost Deferral Account as at December 31, 2018 is $22.99 million.

One has confirmed that the capital expenditure amounts included in the current transmission rates proceeding are based on the assumption that Hydro One will be permitted to capitalize the non-service component of its OPEBs. As such, the capital expenditure amounts in the transmission rates application would need to be adjusted to remove the non-service cost component of OPEBs.

In respect of the distribution business, Hydro One has not indicated how it intends to implement such an outcome. However it is probable that Hydro One will propose to start recovering the amortization of the balance accumulated within its OPEB Cost Deferral account as part of its annual update for 2021 distribution rates[225]. As noted above, the capital expenditures approved in the 2018-2022 distribution rates application excluded the non-service cost of OPEBs, therefore there is no impact on the capital expenditures approved in that application.

If the OEB Does Not Approve Either of Hydro One's Preferred or Alternate Approach:

If Hydro One's request for continued capitalization is denied, and its alternate proposal to continue the OPEB Cost Deferral Account and apply a twenty-year rolling balance disposition method is also denied, then the non-service component of OPEBs would instead be recovered as part of OM&A in the current transmission rates proceeding. This would give rise to a revenue requirement increase of $21 million for the 2020 test-year.[226] Since the current transmission revenue requirement does not reflect these costs in OM&A, Hydro One would need to adjust the test-year OM&A revenue requirement during the draft rate order to reflect this decision. As noted above, Hydro One has confirmed that the capital expenditure amounts included in the current transmission rates proceeding are based on the assumption that Hydro One will be permitted to capitalize the non-service component of its OPEBs. Therefore the capital expenditure amounts in the transmission rates application would need to be adjusted to remove the non-service cost component of OPEBs.

Hydro One has further confirmed that if the OEB denies both is preferred and alternate proposals, then it would also seek disposition of its audited December 31, 2018 balance that has accumulated in its OPEB Cost Deferral Account[227] as part of its deferral and

[225] At the time of its 2021 distribution rates update, the balance in the OPEB Cost Deferral account will be comprised of the audited balance as at December 31, 2019 (so the accumulated 2018 and 2019 amounts).
[226] Argument-in-Chief, p. 75.
[227] The balance in the OPEB Cost Deferral Account as at December 31, 2018 is $22.99 million. Refer to OEB staff's submission on Issue 22 and 23.

variance account disposition in the current transmission rates proceeding.[228] Therefore the disposition request would also need to be updated during the draft rate order process to reflect this outcome.

In respect of the distribution business, Hydro One has not indicated how it intends to implement such an outcome. However it is probable that Hydro One would propose to seek disposition of its audited December 31, 2019 balance in its OPEB Cost Deferral account as part of its 2021 distribution rates update. Since Hydro One's existing distribution rates expire at the end of 2022, it is likely that Hydro One will need to continue accumulating the impacted OPEB costs in the OPEB Cost Deferral account until its next distribution rates rebasing application and seek the periodic disposition of the account balance as part of its distribution rate updates.

OEB Staff Submission

OEB staff notes that to date no other utility that follows USGAAP has requested OEB approval to continue capitalizing the costs that are now prohibited by ASU No. 2017-07, or to establish a deferral account to capture the impact.

With respect to Hydro One's preferred option, OEB staff does not support the continued capitalization of the OPEB costs that are impacted by ASU No 2017-07 on the basis that over the long-term, it is more expensive for ratepayers to fund these costs in rate base as opposed to OM&A due to the return on rate base that is applied to these costs when they are capitalized.

OEB staff has previously expressed concern in Hydro One's last transmission rates and distribution rates Custom IR applications regarding Hydro One's ability to capitalize significantly more costs under a USGAAP based capitalization policy[229]. The OEB expressed a similar concern as part of its Decision on the 2017 and 2018 transmission revenue requirement:[230]

> That said, the OEB shares the concerns of those who question the continued appropriateness of the large capitalization amounts that

[228] Exhibit I, Tab1, Schedule 206, response b).

[229] For example, in EB-2016-0160, Exhibit I-1-75, Hydro One confirmed that on a consolidated basis, it would be able to capitalize approximately $310 million less over the test period had they been required to follow MIFRS.

[230] EB-2016-0160, Decision and Order, dated September 28, 2017, p. 82

USGAAP allows compared to the amounts allowed under MIFRS regulatory accounting purposes.

In OEB staff's view, providing special accommodation to Hydro One that will allow it to continue to capitalize the OPEB costs that are not permitted by USGAAP will only exacerbate this issue further. From a regulatory perspective, OEB staff submits that the requirements of ASU 2017-07 that limit the capitalization of pension and OPEB costs is positive step toward addressing the OEB's concerns over the large capitalization amounts that USGAAP allows compared to MIFRS and still keeps Hydro One whole with respect to its total annual OPEB costs (inclusive of the non-service cost component).

OEB staff further submits that it also does not support Hydro One's alternate approach relating to the continued use of the OPEB cost deferral account to capture the impacted costs. The annual impact of recognizing these costs as OM&A is expected to be approximately $20 million per year for the transmission business (and a similar amount for the distribution business)[231]. As this represents approximately one-percent of the annual revenue requirement,[232] in OEB staff's view, there is no benefit to the added regulatory burden associated with accumulating such costs in a deferral account when the annual rate impact from recognizing these costs in OM&A would be so insignificant.

12. *Does Hydro One's Transmission System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?*

Background

Hydro One stated that its TSP appropriately addresses the unique right and concerns of Indigenous customers and rights-holders[233] and that its approach to addressing the rights and concerns of Indigenous customers and rights-holders is informed by engagement with transmission customers as well as efforts to engage directly with Indigenous communities.

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[231] Refer to Table 1 in J6.4, which shows the expected annual impact on the distribution and transmission businesses for the period 2018-2022.
[232] 20M/$1,642M = 1.2% - The $1,642 million represents the 2020 transmission revenue requirement per Table 2 in Exhibit J1.1.
[233] Argument-in-Chief, p. 80.

Hydro One noted that the OEB had identified[234] as an area for improvement that it should seek and incorporate timely and meaningful input from First Nations representatives and has responded to this direction and developed a TSP that thoughtfully considers and appropriately addresses the unique rights and concerns of Indigenous customers and rights-holders.

The OEB had also found that Hydro One

> …should continue to work diligently with affected First Nations to resolve outstanding permit issues in a timely manner with the objective of providing appropriate compensation while respecting First Nations rights.[235]

Hydro One stated in its evidence that its Indigenous Relations department is leading these efforts in close consultation with the Real Estate, Legal and Regulatory Affairs departments in order to resolve these outstanding matters. As of February 2019, five of the previously outstanding agreements have been finalized and are with the federal government for final permit issuance, while three of the previously outstanding agreements are in active negotiations and one newly expired agreement has entered into the negotiation phase.[236]

Hydro One has also demonstrated its actions addressing the needs and preferences of Indigenous customers and communities in more detail in its evidence.[237]

OEB Staff Submission

OEB staff takes no issue at the present time with Hydro One's ongoing practice in addressing the rights and concerns of Indigenous customers and rights-holders.

[234] EB-2016-0160
[235] EB-2016-0160, Decision and Order, November 1, 2017, page 33.
[236] Exhibit A, Tab 7, Schedule 2, page 7.
[237] Exhibit A, Tab 7, Schedule 2, pp. 4-5.

E: OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

13. *Are the proposed 2020 OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained?*

General OM&A

Background

Hydro One has applied for a 2020 test year OM&A of $374.1 million,[238] which is comprised of the amounts shown in the table below, and which also reflects an update filed October 22, 2019 relating to a new pension valuation:

Table 17 - Summary of Transmission OM&A Expenditures ($ millions)

	Historical								Bridge	Test
	2015		2016		2017		2018		2019	2020
	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Category Level										
Sustainment	233.6	238.7	215.1	241.1	218.1	241.2	229.4	238.5	200.6	214.2
Development	6.1	12.9	4.6	13.4	5.1	4.8	5.2	5.0	6.0	6.9
Operations	59.0	58.5	62.5	59.1	61.1	61.3	53.4	62.1	46.1	48.9
Customer Care	5.1	5.5	4.5	5.5	8.5	4.0	11.0	3.9	7.3	7.5
Common Corporate Costs and Other Costs[260]	73.9	70.2	60.1	71.3	41.5	49.9	54.9	47.5	29.4	30.3
Property Taxes & Rights Payments	63.9	66.3	61.3	67.0	50.7	63.6	65.3	64.3	67.2	68.1
Adjustments										
EB-2014-0140 Settlement Reduction		-20.0		-20.0						
EB-2016-0160 Decision Reduction						-15.0		-15.0		
Removal of B2M Expense		-0.9		-0.7		-0.8		-2.1		
Pension Adjustment						-11.4		-9.9		
Directive[261]									-0.1	-0.1
Pension Adjustment Dec 31, 2018 Valuation[262]										-1.7
Envelope Level										
Total Transmission OM&A	**441.6**	**431.2**	**408.1**	**436.8**	**385.0**	**397.7**	**419.2**	**394.3**	**356.5**	**374.1**

[238] Exhibit J1.1, page 5, October 22, 2019; Argument in Chief Page 85

Hydro One stated[239] that its investment plan is designed to utilize the approved funding to improve reliability and maintain asset condition over the planning period. Hydro One further stated that the investment plan appropriately balances the need to minimize customer rate impacts with the requirements of the system for supporting the delivery of safe and reliable transmission service. Hydro One submitted that its rationale for planning choices is appropriately and adequately explained.[240]

Hydro One stated[241] that its 2019 OM&A expenses are expected to be $38 million or 9.6% lower than the 2018 plan funding envelope. Hydro One indicated that this OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One's planned asset maintenance cycles, and corporate cost reductions. Hydro One stated that it plans to increase its 2020 OM&A expenditures by 5.4% from 2019 levels while still remaining 4.7% below the 2018 plan funding envelope.

OEB staff notes that with Hydro One's revised pension valuation,[242] the updated requested 2020 OM&A of $374.1 million is 4.9% higher than 2019 levels, while still remaining 5.1% below the 2018 plan funding envelope. When compared to the 2018 actual OM&A of $419.2 million, this 2020 requested OM&A is also lower by $45.1 million or a decrease of 10.8%.

OEB staff also notes that Hydro One underspent in 2016 and 2017 actuals, versus OEB-approved. The 2016 actual versus plan was $28.7 million lower or 6.6%. The 2017 actual versus plan was $12.7 million lower or 3.2%.

OEB Staff Submission

OEB staff supports a revised 2020 OM&A of $363.6 million, which is the 2019 forecast of $356.5 million uplifted by the approximate rate of inflation of 2.0%. A revised 2020 OM&A of $363.6 million would represent a reduction of $10.5 million, or 2.8% from the requested 2020 OM&A. OEB staff submits that the revised amount of 2020 OM&A of $363.6 million is appropriate for the following reasons:

i. Hydro One has not shown sufficient evidence of avoided OM&A savings associated with newer capital. More enhanced evidence (e.g. a framework) of

[239] Exhibit F, Tab 1, Schedule 1, Page 4
[240] Argument in Chief Page 83
[241] Exhibit F, Tab 1, Schedule 1, Page 3
[242] Exhibit J1.1, page 2, October 22, 2019

this should be provided going forward. OEB staff provides further discussion below.

ii. 2016 and 2017 OM&A actuals were lower than plan amounts, by 6.6% and 3.2% respectively, which suggests that Hydro One may be over-forecasting its 2020 OM&A.

iii. Requested 2020 Sustainment OM&A of $214.2 million may be overstated as it is not well supported that a deferment of maintenance cycles that occurred in 2019 cannot be repeated again in 2020. OEB staff provides further discussion below on Sustainment OM&A.

iv. Requested 2020 transmission compensation of $680.0 million of which 26% is allocated to 2020 transmission OM&A appears to be too high, as is discussed further below under issue 17 which is whether or not the compensation related costs are appropriate.

v. OM&A productivity savings of $22.0 million incorporated into the 2020 test year OM&A. It is not clear to OEB staff that these are genuine productivity savings. This is discussed under issue 6 which relates to productivity improvements.

Avoided OM&A Savings Associated With Newer Capital

Background

Hydro One provided[243] a high level overview as to how it takes into account the impact of capital spending on its OM&A. Hydro One stated that when it purchases new equipment, the capital plan expenditures are entered into its systems of record, SAP, and will be installed with the maintenance plan suitable for a brand new asset. When the O&M plans are developed, the system would identify them as a brand new asset and the appropriate maintenance plans would be taken into account, and the associated maintenance dollars would then be presented over the plan period. Hydro One stated that the appropriate maintenance plans are identified and those savings are recognized as part of the maintenance plans.

Hydro One provided multiple examples of technological advances that will provide opportunities for OM&A savings, including the following:

[243] Oral Hearing Transcript October 25, 2019, page 90-93

- Hydro One acknowledged that new transformers come equipped with sophisticated dissolved gas monitoring sensors, and that Hydro One is adopting a "condition-based maintenance approach with"[244] those assets.

- Hydro One has adopted the use of new tools such as LineVue to facilitate the condition assessment of transmission lines.[245]

OEB staff notes that many recent technological innovations should enable Hydro One to undertake its operations and maintenance activities more cost efficiently than in past years as innovations are integrated into Hydro One's asset management processes. This is particularly true for newer assets that come equipped with built-in sensors able to facilitate asset management processes such as predictive maintenance. The resulting OM&A savings should increase with the quantum of incremental capital expenditures. Subsequently, Hydro One should be able to secure productivity gains in its OM&A costs, resulting in OM&A expenditures that should increase at a rate lower than inflation.

OEB Staff Submission

OEB staff submits that the avoided OM&A savings associated with new capital have not been adequately quantified by Hydro One. For example, Hydro One confirmed[246] that it cannot quantify the sustainment OM&A expenses that it is saving through the replacement of circuit breakers.

OEB staff is concerned with Hydro One's lack of evidence demonstrating that it has fully accounted for OM&A expenditure savings that should accrue to the benefit of ratepayers. These benefits should accrue as a result of leveraging new technologies and the asset enhancements with which replacement assets come equipped as standard features.

OEB staff's proposed reduction in 2020 total OM&A of $10.5 million is supported by Hydro One's lack of evidence of its leveraging technology and capital expenditures to reduce OM&A.

OEB staff submits that going forward Hydro One's OM&A cost forecasts should reflect productivity gains benefiting the industry due to technological improvements and other innovations. The productivity gains linked to the introduction of time and labour saving

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[244] Oral Hearing Transcript, October 24 2019, Page 23
[245] Oral Hearing Transcript, October 22 2019, Page 8; Page 120
[246] Oral Hearing Transcript October 22, 2019, page 160

condition assessment and evaluation tools and techniques for (i) general and (ii) asset-specific OM&A activities should be measured and tracked.

OEB staff is of the view that more enhanced evidence (e.g. a framework) should be provided going forward as to the avoided OM&A savings associated with newer capital.

OEB staff believes that the lower overall level of OM&A that it is recommending is justified in part by Hydro's One's lack of evidence relating to the incorporation of avoided OM&A savings into the application, which OEB staff believes should be generated given the magnitude of the capital program increases requested.

Sustainment OM&A

Background

Hydro One is requesting 2020 Sustainment OM&A in the amount of $214.2 million.[247] Hydro One noted[248] that the Sustainment OM&A budget is comprised of the investments required for ongoing maintenance to existing transmission lines and stations facilities to ensure their functionality, as originally designed, is maintained.

Hydro One stated that the proposed budget for Sustainment OM&A in the 2020 test year is $13.6 million more compared to the 2019 bridge year (i.e. 2020 $214.2 million versus 2019 $200.6 million), but it is in-line with average historical levels.

OEB staff notes that actual Sustainment OM&A was less than planned OM&A for each of the 2015-2018 rate years, as discussed at the oral hearing.[249] This table is shown below.

[247] Exhibit F, Tab 1, Schedule 1, Page 3, Table 1
[248] Exhibit F, Tab 1, Schedule 1, Page 4
[249] Oral Hearing Transcript October 24, 2019, page 61

Table 18 – Summary of Transmission OM&A Sustainment

OEB Staff Table 4 - Summary of Transmission OM&A Sustainment ($ millions) - Actual versus Plan
Exhibit F, Tab 1, Schedule 3, Page 2, Table 1

	Actual 2015	Plan 2015	Difference	Actual 2016	Plan 2016	Difference	Actual 2017	Plan 2017	Difference	Actual 2018	Plan 2018	Difference	Plan 2019	Plan 2020	Difference of 2020 versus 2018 Plan
											A			B	C = B - A
Sustainment	$ 233.6	$ 238.7	$ (5.1)	$ 215.1	$ 241.1	$ (26.0)	$ 218.1	$ 241.2	$ (23.1)	$ 229.4	$ 238.5	$ (9.1)	$ 200.6	$ 214.2	$ (24.3)
			-2.1%			-10.8%			-9.6%			-3.8%			-10.2%

Hydro One noted[250] that although the magnitude of the Sustainment OM&A difference from plan to actual might look quite large, in its view the difference is only large because the OEB's prior decisions have not been "recast" by Hydro One. Specifically cuts made by the OEB to the OM&A envelope in prior decisions have not been reclassified by Hydro One to reductions to the specific OM&A categories such as sustainment, development, and others.

Hydro One submitted[251] that the proposed Sustainment OM&A budget for the 2020 test year strikes an appropriate balance between the needs of customers, system reliability and the overall stewardship of Hydro One's assets. In Hydro One's view, the resulting investment plan represents the minimum level of investment needed to ensure this balance is achieved.

Hydro One also stated[252] the following:

- The increase in 2020 versus 2019 is necessary to meet the legislated deadlines associated with the polychlorinated biphenyl (PCB) program, fund planned transformer overhauls, support previously deferred preventative maintenance for station assets, and to address the backlog in overhead lines and component inspections and assessments

250 Oral Hearing Transcript October 24, 2019, page 61-63
251 Exhibit F, Tab 1, Schedule 3, Page 1
252 Exhibit F, Tab 1, Schedule 1, Page 4

- The 2019 bridge year forecast for Sustainment OM&A is lower than historical levels partially as a result of a one-time extension of Hydro One's planned asset maintenance cycles[253]

Hydro One stated[254] that a calculation of the impact of "management of maintenance cycles" on 2020 revenue requirement relative to 2018 OEB approved expenditure levels is not possible nor is it a meaningful metric given that 2018 OEB approved OM&A includes several high level adjustments (e.g. the prior OEB decisions to reduce OM&A on an envelope basis).

Hydro One further stated[255] that $6.9 million of the $13.6 million increase in 2020 Sustainment OM&A over 2019, or 50.7% of the increase, is comprised of mandatory PCB retirement (remediation) work to address PCB filled equipment in order to comply with federal PCB regulations. Hydro One added[256] that to manage its OM&A spending, in 2019, it had deferred a planned increase to its PCB program, which resulted in a reduced buffer period to comply with an Environment Canada deadline. Hydro One indicated that it anticipates completing the required PCB remediation by 2024, which is one year later than previously planned, but which leaves only a one-year buffer period for completion of the work within the required timeframe. OEB staff notes that there would be an immaterial decrease of approximately $2 million to the 2020 test year revenue requirement, if the buffer year was eliminated.[257]

Hydro One stated[258] that the 2019 deferment of maintenance was a one-time reduction and such a funding level is not sustainable over the long term. Hydro One further stated[259] that excluding this work from 2020 would in essence take a one-year cut to preventive maintenance and condition assessments, which represent a managed risk and extend it over a four year period (2019 to 2022) which would lead to an unmanaged risk.

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[253] At Exhibit F, Tab 1, Schedule 1, Page 4 Hydro One stated that this includes fewer planned demand and corrective expenditures, extension of the PCB testing and retrofill program, deferral of overhead transmission line preventive maintenance and deferral of vegetation management on select 115kV circuits.
[254] Undertaking J3.3
[255] Undertaking – JT 1.3
[256] Exhibit F, Tab 1, Schedule 3, Page 11
[257] Exhibit I, Tab 01, Schedule 157 (OEB Staff Interrogatory #157)
[258] Exhibit I, Tab 01, Schedule 186 (OEB Staff Interrogatory #186)
[259] Exhibit I, Tab 01, Schedule 184 (OEB Staff Interrogatory #184)

Hydro One also asserted[260] that funding 2020 Sustainment OM&A for this essential maintenance significantly below the historical average (i.e. at 2019 funding levels) would result in two general outcomes:

1. It would complete significantly fewer condition assessments resulting in it having less condition data upon which to make investment decisions

2. It would be unable to prevent further degradation and perform refurbishment work on verified poor condition assets that need to be treated at a greater pace than 2019 levels

OEB Staff Submission

OEB staff submits that if Hydro One's asset management practices have been improved, there should be a better integration of capital and OM&A trade-offs. However, the 2019 deferment only affected OM&A and not capital. Hydro One stated that the reason it looked at expenses is that they have more of an "impact on the revenue requirements that were allocated to us."[261] As the envelopes "are provided by our finance folks,"[262] in order to meet those requirements for OM&A, Hydro One had to make those reductions in those programs. Hydro One stated that the reason capital was not targeted is because the cost of capital impact is significantly much less and therefore the overall impact would be much less in allowing it to meet its envelopes.

OEB staff's proposed reduction in 2020 total OM&A of $10.5 million is supported by a cut that also should be made to 2020 Sustainment OM&A. OEB staff's position is that Hydro One's deferment of maintenance cycles that occurred in 2019 could be repeated again in 2020 to some extent, which would decrease the proposed 2020 OM&A.

OEB staff submits that the proposed 2020 Sustainment OM&A of $214.2 million may also be overstated as it is $13.6 million or 6.8% higher than the 2019 forecasted amount. Although the 2020 Sustainment OM&A of $214.2 million is lower than all previous "plan" amounts since 2015, OEB staff questions why the total increase of $13.6 million versus 2019 is required, when Hydro One is able to operate at the forecasted 2019 level of $200.6 million.

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[260] Undertaking – JT 1.3
[261] *Ibid*
[262] *Ibid*

OEB staff therefore submits that based on prior years spending patterns, Hydro One may be over-forecasting sustainment OM&A requirements in the current application.

OEB staff submits that it is also unclear where Hydro One's one-time extension of its planned asset maintenance cycles in 2019 is concerned, why there was no impact on capital amounts. Hydro One's statement that it did not pursue capital reductions due to the cost of capital impact on its revenue requirement being less than an OM&A impact doesn't provide much clarification of this matter. OEB staff submits that capital amounts should also be considered, along with OM&A when planned asset maintenance cycles are deferred.

Development OM&A

Background

Hydro One is requesting 2020 Development OM&A in the amount of of $6.9 million.[263] Hydro One stated[264] that Development OM&A expenditures consist of costs associated with developing technical standards, technical approaches and solutions, participating in industry research collaborations and subscriptions, and customer power quality.

Hydro One further stated[265] that relative to the 2019 bridge year forecast, it proposes to spend an additional $0.9 million in the 2020 test year. This increase is attributable to its Research, Development and Demonstration (RD&D) Program and additional funding allocated to the Transmission Standards Program.

Hydro One also stated[266] that the 2019 bridge year forecast is slightly higher than 2018 historical year forecast and planned expenditures mainly due to the Transmission Standards Program.

Hydro One noted[267] that the 2018 actual expenditures were $0.2 million higher than the 2018 plan, mainly due to increases in the Customer Power Quality program.

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[263] Exhibit F, Tab 1, Schedule 1, Page 3 Table 1
[264] Exhibit F, Tab 1, Schedule 1, Page 5
[265] Exhibit F, Tab 1, Schedule 1, Page 5
[266] Exhibit F, Tab 1, Schedule 1, Page 6
[267] Exhibit F, Tab 1, Schedule 1, Page 6

OEB Staff Submission

OEB staff submits that Hydro One's 2020 Development OM&A of $6.9 million is reasonable, considering that there are modest increases over the 2019 bridge year forecast (an increase of $0.9 million) and 2018 plan amount (an increase of $1.9 million).

Operations OM&A

Background

Hydro One is requesting 2020 Operations OM&A in the amount of $48.9 million.[268] Hydro One stated[269] that its Operations OM&A expenditures reflect the costs of performing the central transmission operations function at its OGCC, or via[270] the Back-Up Control Centre if the OGCC is rendered unavailable. Hydro One also noted[271] that the Operations function manages the real-time operation of Hydro One's transmission system equipment including: monitoring and controlling transmission assets, coordinating and scheduling planned outages, reacting to system contingencies, provisioning for customer notifications, and reporting on the performance of the transmission system.

Hydro One stated[272] that relative to the 2019 bridge year forecast, it proposes to spend an additional $2.8 million in the 2020 test year to reinstate the Operations Support work programs that were part of a 2019 reduction which Hydro One views as unsustainable.

Hydro One indicated[273] that the 2019 bridge year forecast is lower than 2018 actual and plan expenditures, by amounts of $7.3 million and $16.0 million, respectively. Hydro One stated that the decrease is due to a disallowance of the recovery of executive compensation, reductions resulting from the corporate costing initiative, and a decrease to the Operation Support expenditures.

Hydro One stated[274] that 2018 actuals are lower than the 2018 plan (lower by $8.7 million) and 2017 actual expenditure (lower by $7.7 million), mainly due to lower Operations staff costs.

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[268] Exhibit F, Tab 1, Schedule 1, Page 3 Table 1
[269] Exhibit F, Tab 1, Schedule 1, Page 6
[270] Exhibit F, Tab 1, Schedule 5, Page 1
[271] Exhibit F, Tab 1, Schedule 1, Page 6 & 7
[272] Exhibit F, Tab 1, Schedule 1, Page 7
[273] Exhibit F, Tab 1, Schedule 1, Page 7
[274] Exhibit F, Tab 1, Schedule 1, Page 7

OEB Staff Submission

OEB staff submits that the proposed 2020 Operations OM&A of $48.9 million is reasonable, as it reflects a modest increase of $2.8 million over the 2019 forecasted amount. OEB staff notes that the 2020 Operations OM&A of $48.9 million is significantly lower than all previous “plan” amounts from 2015-2018, which range from $58.5 million (in 2015) to $62.1 million (in 2018).

Customer Care OM&A

Background

Hydro One is requesting 2020 Customer Care OM&A in the amount of $7.5 million.[275] Hydro One stated that this category of OM&A expenditures pertains to the delivery of customer care functions to Hydro One’s transmission customers.[276]

Customer Care OM&A is expected to increase by $3.6 million to $7.5 million in 2020 versus the 2018 plan amount of $3.9 million, or 92.3%.[277] This increase can be partly explained by Hydro One’s statement that “a section of Corporate Affairs, which dealt largely with customer surveys, was reorganized into the Customer Service department.”[278] Hydro One further noted[279] that the increase is primarily related to organizational changes, which includes the customer surveys group as well as other departments.

Regarding “Corporate Affairs OM&A”, OEB staff notes that there is an expected decrease of $3.1 million, or 38.3%, to $5.0 million in 2020, versus a 2018 plan level of $8.1 million.[280] Hydro One confirmed[281] that the 2020 OM&A relating to “Corporate Affairs” of $5.0 million is included in the requested “Common Corporate Costs and Other Costs” amount of $30.3 million.[282]

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[275] Exhibit F, Tab 1, Schedule 1, Page 3, Table 1
[276] Argument in Chief Page 92
[277] Exhibit F, Tab 1, Schedule 1, Page 3, Table 1
[278] Exhibit I, Tab 01, Schedule 188 (OEB Staff Interrogatory #188)
[279] Undertaking – JT 2.43
[280] Exhibit F, Tab 1, Schedule 6, Page 2, Table 2
[281] Undertaking – JT 2.43
[282] Exhibit F Tab 1 Schedule 1 Page 3, Table 1

Relative to the 2019 bridge year forecast, Hydro One indicated[283] that it plans to spend an additional $0.2 million in Customer Care OM&A in the 2020 test year in order to meet its departmental commitments.

OEB Staff Submission

OEB staff is of the view that the requested 2020 Customer Care OM&A of $7.5 million is reasonable, particularly since it is offset by a decrease in the requested 2020 Corporate Affairs OM&A.

Common Corporate Costs and Other Costs

This area is addressed under issue 10 of OEB staff's submission.

Hydro One Accountability Act and the Directive

Background

Hydro One addressed[284] the HOAA and the February 21, 2019 Directive (the Directive) which placed limitations on the amount of compensation paid to Hydro One executives that could be included by the OEB in approving just and reasonable rates from Hydro One Limited or any of its subsidiaries.

Hydro One indicated[285] that the results of addressing the Directive had modest impacts on OM&A and capital, resulting in total reductions of $0.6 million and $2.1 million respectively over the 2019 to 2024 period. Hydro One also stated that the in-year reductions are shown as bottom line adjustments in the respective OM&A and capital exhibits.

Regarding Hydro One's compliance with the HOAA and the Directive, as well as the OEB's Hydro One Networks Distribution decision and order,[286] Hydro One confirmed[287]

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[283] Argument in Chief Page 93
[284] Exhibit F, Tab 4, Schedule 1, Page 34-36; Exhibit I, Tab 01, Schedule 199 (OEB Staff Interrogatory #199)
[285] Exhibit F, Tab 4, Schedule 1, Page 36
[286] EB-2017-0049
[287] Exhibit I, Tab 01, Schedule 199 (OEB Staff Interrogatory #199)

that no additional adjustments are required to its requested executive compensation and Board of Director costs included in its evidence.

OEB Staff Submission

OEB staff takes no issue with Hydro One's approach to its requested executive compensation and board of director costs and submits that no further adjustments are required to the 2020 test year revenue requirement with regard to these matters.

14. *Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the transmission business appropriate?*

OEB staff's submissions for this issue are made under Issue 10.

15. *Are the amounts proposed to be included in the revenue requirement for income taxes appropriate, including consideration of the Accelerated Investment Incentive (Federal Bill C-97)?*

Background

The following table summarizes the regulatory income tax expense amounts that Hydro One is proposing to recover annually over the term of its 2020-2022 custom IR application.[288]

Table 19
Proposed 2020-2022 Regulatory Income Tax Expense

($M)	2020	2021	2022	Total
Regulatory Income Tax Expense	$26.3	$27.2	$40.4	**$93.9**

The regulatory income tax expense amount forms part of the 2020 revenue requirement and is required for the 2021-2022 CRCI calculation.[289]

[288] Exhibit J1.1, Table 2
[289] Specifically, the regulatory income tax expense amount is part of the C-factor calculation.

On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No. 1, was given Royal Assent. Included in Bill C-97 are various changes to the federal income tax regime.

One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive (AII) program, which provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018. The AII's general rule is made up of two elements:

- Applying the prescribed CCA rate for a class to one-and-a-one-half times the net addition to the class for the year.
- Suspending the existing CCA half-year rule (and equivalent rules for Canadian vessels and class 13 property).

As a result of the above change, an eligible capital asset that would have been subject to the half-year rule will, in essence, qualify for an enhanced CCA equal to three times the normal first-year deduction. However, the AII does not change the total amount that a utility can deduct over the life of the eligible capital asset.

On July 25th, 2019, the OEB issued accounting direction regarding Bill C-97 and other changes in regulatory or legislated tax rules for CCA. In this communication, the OEB indicated that it expects utilities to reflect the aforementioned CCA rule changes in their cost-based applications for 2020 rates and beyond.[290]

As part of its interrogatory responses, Hydro One updated its test period regulatory income tax expense calculations on the record of the current proceeding in order to reflect the revenue requirement impact of the new CCA rules for the period 2020-2022.[291] The regulatory income tax expense amounts presented in Table 19 above include the projected impacts of the AII program.

Hydro One has also requested OEB approval to establish a variance account, effective January 1, 2017, that will track the difference between Hydro One's regulatory income tax revenue requirement underlying its approved transmission rates and what that

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[290] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.

[291] Exhibit I, Tab 1, Schedule 208, Attachment 1. The reduction to regulatory tax expense as a result of the AII program was $23.5 million, $34.4 million, and $27.1 million for 2020, 2021, and 2022, respectively (for a total reduction of $85 million)

transmission revenue requirement would have been if its appeal before the Divisional Court related to the tax benefits from its recent IPO is successful. Hydro One has indicated that that since the appeal is ongoing, it is appropriate for the OEB in the present proceeding to provide for the potential outcome of a successful appeal. Hydro One expects this will facilitate the recovery of any amounts that the appeal decision may determine to be recoverable and which relate to periods dating back to January 1, 2017.[292]

OEB Staff Submission

OEB staff has the following concerns related to the regulatory income tax expense amounts that Hydro One is seeking to recover in the current proceeding.

OEB staff submits that Hydro One should revisit its calculations related to the impact of the AII program during the draft rate order in this proceeding and confirm that they do not require any further change or update. Bill C-97 was enacted on June 21, 2019 and Hydro One was asked to quantify the impact soon after. As a result, there may be more information that has since been made available on the application of these new rules that Hydro One had not considered when it provided its initial estimates of the impact.

OEB staff further submits that during the draft rate order phase of this proceeding, Hydro One should also provide the detailed calculations that underpin the regulatory income tax expense amounts that it is seeking to recover in each year of the custom IR term. The calculations currently on the record[293] do not reconcile to the amounts presented in Table 19 above. The calculations should also incorporate the regulatory income tax expense impacts of all matters addressed by the OEB in its decision on this proceeding.

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As noted in the OEB's July 25, 2019 letter regarding Bill C-97, utilities were directed to establish a separate sub-account of Account 1592 - PILs and Tax Variances – CCA Changes, specifically for the purpose of recording the impacts of the CCA rule changes for the period November 21, 2018 until the effective date of a utility's next cost-based rate order.[294]

[292] Argument-in-Chief, p. 99.

[293] The most current regulatory income tax expense calculations are provided in Exhibit I, Tab 1, Schedule 208, Attachment 1.

[294] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.

In that regard, Hydro One has confirmed its intent to follow the OEB's guidance with respect to recording the impacts of the CCA rules changes in a sub-account of Account 1592 for the period November 21, 2018 to December 31, 2019. However, with respect to the 2018 revenue requirement impact, Hydro One stated

> ….it is very unlikely that the projects in-serviced between November 20, 2018 and December 31, 2018 would qualify for Accelerated CCA. Therefore the revenue requirement impact is expected to be immaterial and has not been quantified. In light of the OEB accounting guidance on Bill C-97 Accelerated CCA, dated July 25, 2019, Hydro One is evaluating the 2018 benefits of Accelerated CCA.[295]

OEB staff submits that Hydro One should quantify the 2018 impact of the AII program during the draft rate order phase of this proceeding and confirm that it will record that amount in the new sub-account of Account 1592, as directed in the OEB's July 25, 2019 letter.

For the 2019 revenue requirement impact of the AII program, Hydro One provided an estimate as part of its response to interrogatories[296]. OEB staff submits that the amount that gets tracked in the new sub-account of 1592 should be based on the actual impact, once it is known.

OEB staff does not support the establishment of the proposed variance tracking account related to Hydro One's appeal before the Divisional Court as the Divisional Court appeal proceeding is currently still on-going and the outcome unknown. As a result, OEB staff sees no benefit to the increased regulatory burden associated with tracking a hypothetical amount that may never materialize. OEB staff further submits that a variance account for this purpose should only be established once the need for it is confirmed, which in OEB staff's view, only occurs at the time the outcome of the Divisional Court proceeding is known.

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[295] Exhibit I, Tab 1, Schedule 208, response e).
[296] *Ibid.*

Taxes Other Than Income Taxes

Background

Hydro One is seeking to recover approximately $68.1 million in taxes other than income taxes for the 2020 test year. This balance is comprised of approximately $61.2 million in property taxes and approximately $6.9 million in rights payments. Rights payments refer to payments for certain land right procured under agreement or permits, including rights for transmission facilities to cross and/or occupy properties owned by railway companies and governmental bodies.[297]

OEB Staff Submission

OEB staff notes that the 2020 amount of $68.1 million is consistent with the actual historical trend for taxes other than income taxes for the period 2015-2018.[298] Therefore, OEB staff submits that the amount appears to be reasonable.

16. *Is Hydro One's proposed depreciation expense appropriate?*

Background

Hydro One is seeking the following amounts in respect to its depreciation expense over the term of its Custom IR application:

Table 20
Proposed 2020-2022 Depreciation Expense[299]

($M)	2020	2021	2022	Total
Depreciation Expense	$474.5	$503.4	$528.9	**$1,506.8**

The depreciation amounts are underpinned by an independent depreciation study completed by Foster Associates (Depreciation Study).[300] The Depreciation Study involved a review of Hydro One's existing deprecation rates and the provision of updated depreciation rates. The OEB has historically accepted the Depreciation Study and the

297 Argument-in-Chief, p. 94-95.
298 Exhibit F, Tab 7, Schedule 4, Table 1.
299 Exhibit J1.1, Table 2
300 Exhibit F, Tab 6, Schedule 1, Attachment 1, 2017 Depreciation Rate Review.

methodology set out therein as the basis for determining depreciation expense in Hydro One's transmission rates applications.

The application of the new depreciation rates for 2020 through 2022 reduces the depreciation expense as part of the overall revenue requirement by approximately $4 - $5 million annually compared to if the previously approved rates were maintained.[301]

OEB Staff Submission

OEB staff submits that it accepts the annual depreciation expense presented in Table 20 above on the basis that these amounts were determined by an independent study prepared by a third-party consultant with significant experience in the field[302] and which has prepared the depreciation studies that have underpinned the depreciation rates of previous Hydro One rates applications. The methodology used to determine Hydro One's deprecation rates is consistent with what has been previously accepted by the OEB.

F: COMPENSATION COSTS

17. *Are the compensation related costs appropriate?*

Overall FTEs and Compensation

Background

Hydro One's requested transmission FTEs are as shown in the following table:[303]

Table 21 – Transmission FTEs

FTE Transmission	2017	2018	2019	2020	2021	2022
Total	4,304	4,247	4,474	4,691	4,738	4,613

Hydro One's requested transmission compensation is as shown in the following table:[304]

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[301] Exhibit I, Tab 4, Schedule 11.

[302] Exhibit F, Tab 6, Schedule 1, Attachment 1, 2017 Depreciation Rate Review, p. 5 of 62.

[303] Exhibit I, Tab 01, Schedule 172 (OEB Staff Interrogatory #172)

[304] Undertaking J4.09

Table 22 – Transmission Compensation

	2017	2018	2019	2020	2021	2022
Total Transmission Compensation	617,853,477	609,600,282	628,463,301	680,013,112	706,993,078	705,720,050

Hydro One confirmed[305] that its work program drives the FTEs and then FTEs drive the compensation costs. Hydro One stated that it looks at the work program requirements and then staffs accordingly through its various flexible work force arrangements.

Hydro One indicated[306] that if OM&A and FTEs are compared, the entire work program needs to be considered, including the capital expenditure requirements underlying the application. Hydro One stated that a direct link cannot be made between increasing FTEs and declining OM&A, given that there is a substantial asset need in its capital expenditure profile that would also require FTEs.

Hydro One stated[307] that it is supporting a 26% increase in the Transmission work program over the 2019-2022 period.

In Hydro One's view,[308] it has made progress in reducing and limiting compensation costs, and actively managing the efficiency and size of its workforce. However, Hydro One also indicated that in order to accomplish the work programs reflected in this application and deliver on the important outcomes that the company is committing to, it is necessary for Hydro One to attract, motivate, engage and retain a highly skilled and high performing workforce with appropriate compensation systems.

Hydro One provided[309] an explanation as to why compensation is increasing at a rate faster than inflation, as follows:

- The projected compensation costs[310] contain several underlying factors based on best estimates across each factor, in each year including: forecasted FTE

[305] Oral Hearing Transcript October 25, 2019, page 133
[306] Oral Hearing Transcript October 28, 2019, page 124
[307] Exhibit F, Tab 4, Schedule 1, Page 14
[308] Exhibit F, Tab 4, Schedule 1, Page 1
[309] Undertaking – JT 2.10
[310] Exhibit KT 2.1

changes, base escalation, labour burdens and the allocation between the transmission business and distribution business

- As the compensation forecast includes several interconnected factors, they will not align with inflation rates in isolation

- Hydro One's base wages increases for represented employees are at or below inflation

Hydro One provided[311] an explanation as to why compensation is increasing at a faster rate than FTEs, as follows:

- The 4.2% increase in transmission compensation costs[312] includes compensation costs associated with a 2.2% FTE increase[313] and escalation assumptions in compensation

- Based on the reasons outlined above, overall transmission allocated compensation is increasing at a faster rate than the FTE increases

Hydro One referenced[314] a table in its pre-filed evidence[315] which shows total compensation versus total work programs. Hydro One indicated that it provided an analysis of transmission compensation relative to transmission spend and there is a decline in those ratios. Hydro One stated that the ratio started at 49% and is expected to decrease to 40% in 2022. Hydro One further stated that this decline is partly accounted for by efficiency and outsourcing of certain aspects of its capital program.

Hydro One provided the following table[316] which shows the FTE changes for both Hydro One transmission and distribution:

[311] Undertaking – JT 2.10
[312] Exhibit KT 2.1, line 111
[313] Exhibit KT 2.1, line 166
[314] Oral Hearing Transcript, October 28, 2019, page 157
[315] Exhibit F, Tab 4, Schedule 1, Page 34
[316] Undertaking – JT 2.07

Table 23 – FTE Change by Items

FTE Change by Items listed below F-04-01 Table 2				
	Supports either Transmission, Distribution or both	**2019**	**2020**	**2022**
Repatriated Customer Call Centre (1)	Dx	-8	-	-
Shared Service **Supply Chain Strategic Plan (2)** **Fleet Mechanics apprentices (6)** **Helicopter Services (7)**	Both	75	-6	13
Distribution Work Program (4)	Dx	415	-6	131
Transmission Work Program (3)	Tx	200	-36	-165
Health & Safety (7)	Both	28	-1	-3
Great Lakes Power (Hydro One Sault Saint Marie) (5)	Tx	-	-	-
Total		**710**	**-49**	**-24**

Hydro One indicated the following:[317]

- The increase of 200 FTEs in the 2019 transmission work program is primarily caused by the transfer of non-regular lines apprentices from the distribution line of business to transmission.

- The reductions shown in 2020-2022 represent decreases in the direct hire casual trade workforce, as a result of expected efficiencies due to progressive productivity savings.

Hydro One confirmed[318] that there are only 200 FTEs that are being transferred or reclassified from distribution to transmission. As well, Hydro One confirmed that there are no significant FTEs that are being transferred from transmission to distribution. Hydro One also noted that the 415 FTE increase relating to distribution "is a reflection of the

[317] Undertaking – JT 2.07

[318] Oral Hearing Transcript October 29, 2019, page 2 & 3

plan that was outlined as per the previous application to support the previous distribution application."[319]

Hydro One further indicated[320] that due to the timing of the distribution decision which occurred on March 7, 2019 and the initial March 21, 2019 filing for the current transmission application, Hydro One did not have "sufficient opportunity to restate all of the FTEs to align with that distribution reduction."[321] Hydro One also stated that when it comes back and files for the joint application (2023 rates), some of those pieces will be clarified. Hydro One stated[322] that there is no "double counting" of FTEs between transmission and distribution when the lines of businesses provide their requirements to fulfil the work program that has been outlined. However, Hydro One also noted that there is also "in-year accounting for movements."[323]

Hydro One described[324] the movements in more detail (i.e. year over year increase in Total Transmission Cost per FTEs) stating that that these small increases during the test period are largely due to base escalations which subsequently result in increases in the various components that make up the labour burdens, labour burden changes, and allocation differences year over year between Transmission and Distribution.

OEB staff notes that these increases may not be seen as small, as described by Hydro One, as the year-over-year increases between 2019 and 2022 range from 2.5% to 3.2%, when also incorporating the updated pension valuation amounts.

OEB Staff Submission

OEB staff notes that Hydro One is requesting a 2020 transmission compensation level of $680.0 million of which 26% is allocated to 2020 transmission OM&A and 74% to capital.[325] OEB staff submits that this amount may be overstated for the following reasons.

i. The increase in compensation is excessive given: (1) repeated concerns expressed by the OEB about Hydro One's compensation levels in prior decisions, and (2) Hydro One's statements about its improved productivity in the current application

[319] Oral Hearing Transcript October 29, 2019, page 3
[320] Oral Hearing Transcript October 29, 2019, page 4
[321] Oral Hearing Transcript October 29, 2019, page 4
[322] Oral Hearing Transcript October 29, 2019, page 6 & 7
[323] Oral Hearing Transcript October 29, 2019, page 7
[324] Undertaking J5.9
[325] Undertaking J4.09

ii. Much of the increase in compensation has been attributed to the needs of the growing capital program (with 74% of 2020 compensation allocated to capital). As there is a cut recommended in the work program for capital, there should also be a related compensation cut which would impact both capital and OM&A

iii. The Mercer "market median" level of compensation may be overstated. As a result, the reduction of Hydro One's requested compensation incorporated into the 2020 revenue requirement to this market median level may be understated and further reductions may be required.

iv. The amounts paid to contract staff (i.e. staff not included in FTEs) may mask an even higher level of compensation being paid out than that reflected in the requested 2020 compensation amount.

v. The total burdens excluding pension and OPEB may be overstated, as OEB staff could not reconcile its estimated calculations of these burdens to the amounts requested by Hydro One in the compensation spreadsheets.

vi. The year over year increases in Total Transmission Cost per FTEs between 2019 and 2022 are higher than the inflation rate of approximately 2.0%.

Based on a simple growth rate analysis, OEB staff has shown the increases in compensation and FTEs in the following table. OEB staff notes that this table has not been updated to reflect the new pension valuation, however, the table remains directionally consistent:

Table 24 – Movements in Hydro One Transmission and Distribution Compensation and FTEs

OEB Staff Table 11 - Movements in Hydro One Transmission and Distribution Compensation and FTEs
Exhibit KT2.1

	2022 versus 2018		2020 versus 2018	
	Total % Change	**Annual % Change**	**Total % Change**	**Annual % Change**
Total Transmission Compensation	17.00%	4.20%	12.50%	6.30%
Total Distribution Compensation	14.80%	3.70%	8.30%	4.10%
Total Transmission FTEs	8.60%	2.20%	10.50%	5.20%
Total Distribution FTEs	8.70%	2.20%	6.50%	3.30%

OEB staff is also of the view that further improvements to the presentation of compensation information are required.

OEB staff discusses these concerns in more detail below:

Market Median Compensation

Background

The Mercer Market Median calculation is designed to determine what would be Hydro One's total transmission compensation costs if they were at the P50 level, so at the "market median." The calculation shows the difference between what Hydro One is requesting and what that market median level would be. Based on the Mercer study, the gap is quantified from 2017 and projected to market going forward.[326]

Hydro One stated[327] that it is not possible for it to be at the 50th percentile, as it does not reflect the reality of its collective bargaining process. Hydro One indicated that it is over 90% unionized. Hydro One noted that collective agreements are currently in place, and it

[326] Oral Hearing Transcript, October 29, 2019, page 55-57
[327] Oral Hearing Transcript, October 29, 2019, page 57-58

has made significant movements to reduce a number of compensation elements, either maintaining them at market, at the Consumer Price Index (CPI), or below. Hydro One acknowledged that it is not easy to make these kind of changes.

Regarding the five total compensation studies (2008, 2011, 2013, 2016, and 2017) that have been conducted by Mercer Canada, the following table[328] below shows that while Hydro One improved in the 2008 to 2017 period by 5%, it worsened by 2% in the more recent 2013 to 2017 period. While the results since 2016 are encouraging, it is not a sufficient period of time in order to establish a trend.

Table 25: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median

Employee Group	2008 Survey Results	2011 Survey Results	2013 Survey Results	2016 Survey Results	2017 Survey Results	Total Change from 2008 to 2017
Management	-1%	-17%	-1%	2%	1%	2%
Society	5%	5%	9%	11%	12%	7%
PWU	21%	18%	12%	16%	12%	-9%
Overall	17%	13%	10%	14%	12%	-5%

**Management employee group positioning of -17% to market median likely impacted by legislative freeze for non-represented compensation.*

Therefore, it is not clear whether Hydro One has aligned the amount of compensation to be recovered in the 2020 revenue requirement with Mercer's "market median" level of compensation. The alignment of the compensation to the market median was an adjustment required by the OEB in the Hydro One Distribution decision and order.[329]

Hydro One confirmed[330] that the impact on the 2020 test year revenue requirement if its compensation was to be brought to market median for its transmission business is $38.6 million, with $10.1 million being the OM&A component of this amount. As described further below, Hydro One is of the view that additional reductions of $20.1 million related

[328] Exhibit F, Tab 4, Schedule 1, page 38
[329] EB-2017-0049 March 7, 2019, page 3
[330] Technical Conference Transcript August 13, 2019, page 40

to capital would need to be incorporated into the amount of compensation to be recovered in the 2020 revenue requirement to align with the market median.

However, Hydro One also indicated[331] that its consultant, Willis Towers Watson, had recommended a 2019 salary increase budget of 2.5% for management, along with recommending no adjustments to the salary structure.

Hydro One originally confirmed[332] that $9.6 million of the $10.1 million OM&A component is already reflected in its 2020 test year revenue requirement. Based on what was stated in the technical conference, Hydro One was previously of the view that only $0.5 million needed to be subtracted from the requested OM&A related to compensation to align the amount of compensation to be recovered in the 2020 revenue requirement with Mercer's "market median" level of compensation.

However, Hydro One filed new information associated with an updated pension valuation[333] on October 17, 2019. Although it appears in the following table that $1.2 million needs to be added to its requested compensation, Hydro One confirmed[334] that it is not seeking recovery of this amount of $1.2 million.

Table 26 – Revised Impact on the Mercer Market Median Reductions to the 2020 Test Year Revenue Requirement OM&A from the Revised Pension Valuation

Net Mercer Median Reductions Allocated to OM&A ($M)	2020
Mercer Median - Tx OM&A	10.1
Pension Reduction OM&A	(5.5)
OPEB Reduction OM&A	(2.4)
Executive Comp. Reduction	(1.5)
The Directive	(0.1)
Total Net Mercer OM&A Reductions	0.5
Updated Pension Reduction OM&A	(1.7)
Total Net Mercer OM&A Reductions	(1.2)

331 Exhibit I, Tab 01, Schedule 178 (OEB Staff Interrogatory #178)
332 Technical Conference Transcript August 13, 2019, page 40, 42
333 October 17, 2019 Exhibit JT-2.31, Attachment 1
334 Oral Hearing Transcript October 28, 2019, page 152

Hydro One originally provided the breakdown[335] of the $28.5 million capital amount impacting the 2020 test year revenue requirement to bring the compensation to market median. Hydro One indicated that a $24.3 million reduction to the capital related to compensation was required.

However, as noted above, Hydro One filed new information associated with an updated pension valuation. Hydro One confirmed[336] that there is an amount of $20.1 million of capital-related above-median compensation, comprised of capital expenditures. This $20.1 million amount is shown in the table below. Hydro One further stated that the typical rule of thumb that is used for a rate base change to revenue requirement is approximately 8% to 9%.

Table 27 – Revised Impact on the Mercer Market Median Reductions to the 2020 Test Year Revenue Requirement Capital from the Revised Pension Valuation

Net Mercer Median Reductions Allocated to Capital ($M)	**2020**
Mercer Median - Tx Capital	28.5
Pension Reduction Capital	(3.0)
OPEB Increase Capital	1.7
Executive Comp. Reduction	(2.6)
The Directive	(0.3)
Total Net Mercer Capital Reductions	**24.3**
Updated Valuation Pension Reduction Capital	(4.2)
Updated Total Net Mercer Capital Reductions	**20.1**

OEB Staff Submission

OEB staff has assumed that the $20.1 million amount above is a capital addition and not a capital expenditure and has applied an 8.5% rate base change to revenue requirement (i.e. the midpoint of Hydro One's above noted estimated of 8% to 9%). OEB staff has calculated the approximate impact on the revenue requirement of the $20.1 million

335 Undertaking – JT 2.9

336 Oral Hearing Transcript October 25, 2019, page 155

capital amount to be a $1.7 million impact that needs to be reduced from Hydro One's 2020 revenue requirement.

Mercer also indicated[337] that regarding the calculation of the market median compensation, an assumption was made that the marketplace would move for non-represented employees at a rate of CPI plus 0.6%. Hydro One also clarified[338] that the calculations performed for the market median calculations factored in higher than typical compensation levels for management.

OEB staff accepts Hydro One's position that it does not need to add any amounts to Hydro One's requested OM&A related to compensation to bring it to the market median amount. OEB staff also submits that the $20.1 million capital amount translates to a $1.7 million impact that should be removed from Hydro One's proposed 2020 revenue requirement. OEB staff invites Hydro One to provide the actual revenue requirement impact amount in its reply submission, if different from $1.7 million.

However, given Hydro One's above noted position on the adjustments required to bring its compensation to a market median level, OEB staff submits that Hydro One may need to further reduce the amount of compensation to be recovered in the 2020 revenue requirement for the following reasons:

1. Hydro One is not making sufficient advances in reducing its compensation to market levels, as Hydro One's position relative to market worsened by 2% in the 2013 to 2017 period, as shown in the above "Table 25: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median."

2. The level of FTEs assumed in the market median compensation calculation may be overstated, given OEB staff's above noted submission on this issue. With higher assumed FTEs, the market median compensation would be inflated.[339]

3. Hydro One indicated that its market median calculations factored in higher than typical compensation levels for management, as well as reflecting an increased

[337] Oral Hearing Transcript, October 28, 2019, page 149 & 150
[338] Oral Hearing Transcript, October 28, 2019, page 153
[339] Undertaking – JT 2.15 Hydro One indicated that the market median calculation is based on the differential between the average salary and the market median rate for the corresponding level, multiplied by the number of incumbents in the relevant level based on the FTE forecast found in the Compensation Spreadsheet.

compensation rate of CPI plus 0.6%, which is higher than inflation of approximately 2.0%.

OEB staff is of the view that going forward, Hydro One should take more initiatives to reduce compensation levels, to bring it more in line with market based compensation. Although Hydro One noted that it has "taken steps to keep costs as low as reasonably possible"[340] and requires "appropriate compensation systems"[341] for its employees, Hydro One's level of compensation is not moving towards the market median at an acceptable pace. OEB staff submits that Hydro One should file a plan for its next application (2023 to 2027 rates), for transitioning to the 50th percentile by the end of the next Custom IR term.

Burdens

Background

Hydro One explained[342] that the increase in total burdens for both its transmission and distribution businesses is mainly due to the following drivers. The main drivers for the increases are due to higher FTE levels and base escalation assumptions which subsequently result in increases in the various components that make up the labour burdens. Hydro One also indicated[343] that costs to the employer such as the Canada Pension Plan are also increasing. Other than pension and OPEB, Hydro One indicated[344] that it incurs additional burdens such as costs relating to the Canada Pension Plan, employment insurance, employee health tax, Workplace Safety and Insurance Board, group life insurance, and health and dental.

Hydro One stated[345] that the total burden amounts included in the Compensation Spreadsheet[346] are calculated by applying an assumed burden percentage to base pay. Hydro One noted that the assumed burden is based on Hydro One's estimate of its FTE requirements to execute the TSP included in the application. However, Hydro One noted

[340] Exhibit F, Tab 4, Schedule 1, Page 1
[341] Exhibit F, Tab 4, Schedule 1, Page 1
[342] Undertaking – JT 2.11
[343] Oral Hearing Transcript October 29, 2019, page 18
[344] Exhibit I, Tab 08, Schedule 22 (PWU Interrogatory #22)
[345] Undertaking J6.1
[346] Lines 6, 17, 36, 46, 60, 70, 87, and 99

that the pension and OPEB burden amounts included in the Compensation Spreadsheet[347] are derived differently, as follows:

- 2014 to 2018 are based on actuals
- 2019 to 2022 are based on an actuarial valuation dated effective December 31, 2017 which is based on historical FTE numbers and does not consider the same assumptions for future FTE growth as the total burden amounts[348]

OEB Staff Submission

OEB staff submits that there are differences in Hydro One's proposed burden amounts that have not been adequately explained. Based on an undertaking response,[349] and also row 206 from an OEB staff exhibit,[350] the following table has been prepared by OEB staff to show these inadequately explained differences:

Table 28 – Unexplained Differences between Burdens

	2018	2019	2020	2021	2022
Total Burdens TX (Row 206) Excluding P&OPEB A	30,434,548	47,206,325	54,558,268	59,527,969	61,099,204
J6.1 Burden Excluding P&OPEB - Transmission B	24,527,313	25,723,508	28,134,664	29,303,622	29,276,017
Unexplained Difference A - B	5,907,235	21,482,817	26,423,604	30,224,347	31,823,187

It is OEB staff's understanding that the "unexplained differences" in the above table show approximately how much the total transmission burdens have been uplifted. The amounts have been uplifted by updating the transmission pension & OPEB amounts shown on row 149 of an OEB staff exhibit[351] to reflect the forecasted FTEs in the application, versus the historical FTEs used in the actuarial valuation. As a result, OEB staff submits that the burden amounts that flow into capital and OM&A amounts reflected in the analysis provided for 2019 to 2022 (including the 2020 test year revenue requirement) cannot be fully supported by items such as Hydro One's actuarial valuation.

[347] Lines 147, 148, 151, 152
[348] Lines 6, 17, 36, 46, 60, 70, 87, and 99
[349] Undertaking J6.1
[350] Exhibit K6.1
[351] Exhibit K6.1

OEB staff submits that these unexplained differences in burdens, with the unexplained amounts representing significant increases, provide further support for OEB staff's proposed reduction in 2020 total OM&A in the absence of a clearer explanation for this differential by Hydro One than that provided in its undertaking responding to OEB staff's concerns.[352]

Contract Staff

Background

Hydro One stated[353] that it has two types of contractors:

1. Professional services-type contractors which are used for its IT operations, as well as for project management type functions that are project-based

2. Contractors used for contracting out pieces of its operations (e.g. cable locates, capital programs) to scale up

Hydro One stated[354] that it does not have available a full-year forecast of contract staff spend for 2019, nor a detailed 2020-2022 forecast at this level. Hydro One could not provide detail of the amounts that are rolled into the 2020 revenue requirement related to contract staff.

Hydro One indicated[355] that it is not able to quantify the impact on the 2020 revenue requirement, if amounts paid to contract staff were instead paid to employees of Hydro One and rolled into the FTE count.

Hydro One noted[356] that going forward with the growth in the transmission capital portfolio, it intends to have an increased reliance on contractors to perform both the engineering and construction elements of its work program execution. Hydro One stated that historically approximately 10% of its power system work has been contracted out, and moving forward this is going to trend up to about 30% so that it can build both scale and capacity with the flexible work force.

[352] Undertaking J6.1
[353] Oral Hearing Transcript October 28, 2019, page 31
[354] Technical Conference Transcript August 13, 2019, page 36-38
[355] Technical Conference Transcript August 13, 2019, page 37-38
[356] Oral Hearing Transcript October 21, 2019, page 157 & 158

Hydro One stated[357] in its comparisons the costs between its internal and external workforce are very similar, the predominant reason being that the labour rates in the construction trades within Ontario are set at the provincial level, and whether a person works for Hydro One or one of the multitude of contractors, the actual labour rates are identical from one employer to the next.

Submission

OEB staff's proposed reduction in 2020 OM&A is supported by the lack of clarity provided by Hydro One with respect to its contractor costs. Hydro One could not provide detail of the amounts rolled into the 2020 revenue requirement related to contract staff and Hydro One was not able to quantify the impact on the 2020 revenue requirement, if amounts paid to contract staff were instead paid to employees of Hydro One and rolled into the FTE count.

<u>Compensation Spreadsheet – Compliance with Prior Decisions</u>

Background

Hydro One stated[358] that the Compensation Spreadsheet is "consistent with the OEB's findings in EB-2016-0160 and the compensation evidence filed in Hydro One's 2018-2022 Distribution Custom IR application (EB-2017-0049)."[359] Hydro One also stated that the Compensation Spreadsheet "provides actual total compensation cost for Hydro One Networks and for both the distribution and transmission businesses for 2014 to 2018 and forecast total compensation cost for the years 2019 to 2022."[360]

In the Hydro One Distribution decision and order,[361] the OEB agreed with OEB staff that a consistent template for presenting compensation costs was required. The OEB directed Hydro One to develop such a template based on the direction provided by the OEB in the last transmission rate proceeding. The OEB also noted[362] the following:

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[357] Oral Hearing Transcript October 22, 2019, page 80
[358] Exhibit F, Tab 4, Schedule 1, Page 32
[359] *Ibid*
[360] *Ibid*
[361] EB-2017-0049 March 7, 2019, page 112
[362] EB-2017-0049 March 7, 2019, page 95

> The OEB is reducing the 2018 proposed budget by $10 million (from $576.7 million to $566.7 million) to account for Hydro One's past cost performance. This will bring it in line with the average actual spend in the 2015 to 2017 period ($565.6 million).

In response to the OEB's direction in the last transmission rate proceeding decision,[363] Hydro One noted[364] that it had addressed in the distribution proceeding the first six of the seven items labeled (a) through (g), as requested by the OEB. Hydro One further noted that the seventh item (g) was addressed in an undertaking[365] in the current proceeding.

Hydro One confirmed[366] that there are no inconsistencies in the way the compensation information is presented in this application that have not been remedied through interrogatories in this proceeding. However, Hydro One agreed to address item g) of the prior transmission decision in an updated Compensation Spreadsheet.

Hydro One indicated[367] that there are no items that may make the compensation methodology between the previous distribution proceeding and the current proceeding difficult to compare. Hydro One further noted that the compensation information is comparable between these two proceedings.

OEB Staff Submission

OEB staff filed an exhibit[368] during the technical conference, which showed the following:

Table 1 - Unexplained Differences in Hydro One Dx Compensation

	2019	2020	2021	2022
HONI Dx Compensation as per SEC IRR #58 (EB-2019-0082)	696,305,295	670,598,684	678,717,027	710,781,454
HONI Dx Compensation as per Exh C1/Tab 2/Sch 1/p. 48 Appendix B (EB-2017-0049)	642,530,718	631,275,350	616,248,742	622,009,219
Unexplained Difference	53,774,577	39,323,334	62,468,285	88,772,235

363 EB-2016-0160 Revised November 1, 2019, decision and order, page 56 & 57
364 Undertaking J5.6
365 Undertaking J5.5
366 Oral Hearing Transcript, October 28, 2019, page 132
367 Oral Hearing Transcript October 28, 2019, page 136
368 Exhibit KT2.1, worksheet "Comp & FTE_OEB staff" of this spreadsheet

Table 2 - Unexplained Differences in Hydro One Tx & Dx FTEs				
	2019	**2020**	**2021**	**2022**
HONI Total FTEs (Tx + Dx) as per SEC IRR #58 (EB-2019-0082)	9,216	9,146	9,183	9,160
HONI Total FTEs (Tx + Dx) as per Exh C1/Tab 2/Sch 1/p. 9, Table 1 (EB-2017-0049)	8,505	8,488	8,474	8,467
Unexplained Difference	711	658	709	693

Hydro One indicated that "Table 1 compares the distribution compensation from EB-2019-0082 and EB-2017-0049, and is not relevant to the current transmission application."[369]

Hydro One stated[370] that differences in FTEs between the previous Hydro One distribution proceeding[371] and the current Hydro One transmission proceeding can be explained by the different business plans underpinning these respective rate filings. Hydro One also listed[372] some of the changes that drive the variance between the two business plans for 2019.

OEB staff notes that item (b) which requested the "total number of employees" (i.e. headcount), has not been included for the forecasted periods in the Compensation Spreadsheet and has only been included for the historical periods (2014-2018).

Hydro One indicated[373] that historically the submitted headcount used to be the only headcount number in its evidence, which has been subsequently transformed into a FTE view. Hydro One indicated that the headcount number was left in the Compensation Spreadsheet as a "bridge", however going forward Hydro One will use a FTE plan.

The usefulness of the total number of employees, versus the number of FTEs, was also explored by the OEB panel during the oral hearing[374] where it was commented that headcount is "not very meaningful,"[375] and "the FTE is much more useful because it annualizes some fluctuations in headcount."[376]

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[369] Undertaking JT 2.08
[370] Exhibit I, Tab 01, Schedule 172 (OEB Staff Interrogatory #172); Undertaking JT 2.08
[371] EB-2017-0049
[372] Undertaking JT 2.08
[373] Oral Hearing Transcript October 28, 2019, page 133 & 134
[374] Oral Hearing Transcript, October 28, 2019, page 134
[375] *Ibid*
[376] *Ibid*

OEB staff agrees that Hydro One has addressed in the current proceeding all of the items labeled (a) through (g), as requested by the OEB in the prior transmission proceeding, except for item (b) which requested the "total number of employees." OEB staff submits that the lack of Hydro One providing the "total number of employees" or "headcount" for forecasted periods is not critical, as the number of FTEs has been forecasted, which may be more useful to the OEB. OEB staff submits that Hydro One should only be required to provide FTEs going forward, instead of the total number of employees.

As the OEB was also concerned that Hydro One's past forecasts were not in line with actual spend, OEB staff is of the view that more evidence needs to be filed in future proceedings to provide greater comparability of compensation amounts and FTEs between the different proceedings.

OEB staff notes that Hydro One Networks includes two regulated arms – its distribution business and transmission business. As a result, it would be logical to assume that any compensation and FTE policies and practices from a distribution proceeding would also inform and be relevant to a transmission proceeding.

OEB staff submits that Hydro One's explanation that the different filed distribution amounts are not relevant to this proceeding is not sufficient. OEB staff also submits that Hydro One's explanation that its proposed FTEs in the past distribution proceeding, versus the current proceeding, vary due to different underlying business plans needs to be enhanced going forward in its next rebasing application (2023) to provide sufficient comparability.

As the next Hydro One application will include both transmission and distribution, OEB staff submits that these types of concerns related to differences between the two regulated arms should be easier to deal with.

Pension and Other Post Employment Benefit Costs

Recovery Methodology

On September 14, 2017, the OEB released its Report on the Regulatory Treatment of Pension and Post-Employment Benefit (OPEB) Costs (the OEB Report). The OEB Report describes the OEB's policy 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. It 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. For utilities that propose to set rates using a method other than accrual, the OEB Report requires that such a proposal be supported with evidence that gives consideration to factors such as providing value to customers, fairness, intergenerational equity, and other principles and practices enunciated in the OEB Report.

As part of the current application, Hydro One has proposed to recover its test period OPEB costs on an accrual accounting basis and its pension costs on a cash basis. This is consistent with the recovery methodologies that were approved in Hydro One's recent distribution rates proceeding.[377]

The OEB Report was released after the delivery of final arguments in the previous transmission rates proceeding. In that proceeding, the OEB panel approved the use of the cash method for pension costs and accrual method for OPEB costs and addressed the continued use of the cash method for pensions in the context of the OEB Report:

> If Hydro One proposes to continue using the cash method as the basis for recovering its pension costs beyond December 31, 2018, then, in its next transmission revenue requirement proceeding, Hydro One will provide evidence that addresses the principles, practices, and policy determinations in accordance with the provisions of the Pension and OPEBs Report.[378]

To that end, Hydro One supported its request to recover pension costs on a cash basis in the current proceeding by indicating that its ratepayers are better off under the cash method because it results in lower costs recovered though rates, it is more predictable, and switching to the accrual method could have a negative effect on both current and future ratepayers. Hydro One further provided a historical analysis that compared the amounts collected in rates on a cash basis to what would have been collected in rates had the accrual method been used. The results of this analysis indicate that on a year-to-year basis the rates under either method, for the most part, would have been reasonably consistent. However, on a cumulative basis the cash method has historically provided more value to ratepayers.[379]

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[377] EB-2017-0049
[378] EB-2017-0049, September 28, 2017 Decision and Order, p. 81
[379] Exhibit I, Tab 1, Schedule 202

OEB Staff Submission

OEB staff submits that the use of the accrual method by Hydro One to recover its OPEB costs is appropriate as it is consistent with the default methodology prescribed in the OEB Report.

With respect to the methodology to recover pension costs, OEB staff notes that, as directed in its previous transmission rates application, Hydro One has provided the evidence required in support of its use of the cash method as the basis to recover its pension costs. The OEB Report also 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.[380] 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 at this time of the cash method by Hydro One to recover its pension costs is justified.

Pension and Other Post Employment Benefit Costs – Amounts Proposed for Recovery in the Test Period

Background

Hydro One is seeking to recover the following amounts related to its pension and OPEB costs in the 2020 test period:

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

Table 29
Proposed Test Period Pension and OPEB Costs

Test Year 2020 ($M)	Pension[381]	OPEBs[382]	Total
OM&A	$9.3	$16	$25.3
Capital	$22.8	$18	$40.8
Deferral Account[383]		$21	$21.0
Total	$32.1	$55	$87.1

Hydro One's OPEB costs are underpinned by a December 13, 2017 projection report that was prepared by Willis Towers Watson and provided the projected benefit cost for the period 2018 – 2023 prepared in accordance with USGAAP (i.e. prepared under the accrual accounting methodology)[384]. Hydro One has reconciled the amounts presented in the Willis Towers Watson report to the total amount for OPEBs that it is seeking to recover in 2020.[385]

For pension costs, Hydro One provided its December 31, 2017 pension valuation as part of its initial evidence on the record of this proceeding.[386] However, the amount of pension costs it was seeking to recover in the test period was not underpinned by that pension valuation; it was instead based on the December 13, 2017 Willis Towers Watson report

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381 Hydro One filed an updated pension valuation on October 17, 2019, the December 31, 2018 valuation. This valuation updated the test period amount for pension costs which was previously presented in Table 1 of Exhibit F, Tab 5, Schedule 1. On October 22, 2019, Hydro One filed Undertaking J1.1, which presented updates to the revenue requirement, including the impact of the December 31, 2018 pension valuation. Based on Table 1 of that undertaking the updated valuation reduced the OM&A component of pension costs by $1.7M. Based on Table 6 of the same undertaking, the updated valuation reduced the capital component of pension costs by $4.2M. Therefore using the original revenue requirement amount for pensions from Table 1 of Exhibit F, Tab 5, Schedule 1, the updated test period OM&A and Capital component of pension costs is: OM&A ($11-1.7 = $9.3) and Capital ($27-4.2 = $22.8)

382 Exhibit I, Tab 1, Schedule 221

383 The deferral account captures the portion of OPEB costs that are impacted by the USGAAP standard update ASU 2017-07. The OEB previously approved the use of a deferral account to capture the impacted costs until a decision is made on the regulatory treatment of the impacted costs in this proceeding. This issue is addressed in Issue 11. Depending on the outcome, the amount in the deferral account will either be included in rate base, recognized in OM&A, or continue to be recognized in the deferral account. Therefore depending out the outcome of Issue 11, the test period pension amounts as presented in this table may need to be adjusted.

384 Exhibit I, Tab 1, Schedule 205, Attachment 1.

385 Undertaking JT-2.3

386 Exhibit F, Tab 5, Schedule 1, Attachment 1

that projected Hydro One's annual benefit costs for the period 2018 – 2023.[387] Hydro One explained that the projection report prepared by Willis Towers Watson was more appropriate to use as the basis for its test period pension costs because it included assumptions related to the pension contributions that Hydro One would incur as a result of the Inergi / Vertex transfer once it is approved by the Financial Services Regulatory Authority of Ontario (FSRA). The December 31, 2017 pension valuation did not take those employees into account as it was based on the actual plan headcount as at the valuation date.[388]

However on October 17, 2019, Hydro One had filed an updated pension valuation, the December 31, 2018 pension valuation.[389] Hydro One has confirmed that this valuation includes assumptions related to the Inergi / Vertex transfer and is the basis for its revised pension contributions as presented in Table 29 above.[390]

OEB staff also notes that Hydro One's December 31, 2018 pension valuation is prepared under the new funding rules that were enacted effective May 1, 2018 pursuant to section 55.1 of the *Pension Benefits Act* (PBA) and O.Reg. 250/18. Hydro One's previous valuation, the December 31, 2017 valuation (on the record of the current proceeding), was prepared based on the pre-May 1, 2018 funding rules and indicated that Hydro One was eligible to take a contribution holiday in the test period 2020. According to the new funding rules a private sector employer, such as Hydro One, is only permitted to take a contribution holiday in a year in which an actuary certifies that the pension plan has a funded ratio of at least 105% calculated on a wind-up basis. Based on Hydro One's December 31, 2018 valuation, it does not meet this threshold test. Therefore the actuary has confirmed that Hydro One is legally obligated under the PBA to make pension contributions in 2019, 2020, and 2021.[391]

OEB Staff Submission

Based on the evidence provided on the record of this proceeding, the amounts being proposed for recovery in respect to pension and OPEB costs for the test period 2020 are underpinned by valuation reports and projections that have been prepared by a licensed

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[387] The December 31, 2017 pension valuation presented $69 million in total Hydro One pension contributions for 2020, whereas the December 13 Willis Towers Watson report projected $78 million in total Hydro One pension contributions.
[388] Exhibit I, Tab 1, Schedule 203, response to b).
[389] JT-2.31, Attachment 1.
[390] Transcript Volume 6, p. 27-28
[391] Exhibit JT-2.31, Attachment 1, p. 15 of 59, it indicates that Hydro One is required to make pension contributions of $66.5 million, $66 million, and $65 million in 2019, 2020, and 2021 respectively.

actuary in accordance with accepted actuarial practice in Canada and other legislation (i.e. PBA). OEB staff typically relies on such valuations when assessing the reasonability of the pension and OPEB amounts that a utility seeks to recover in its rates application, provided that it has no concerns with the management assumptions that were used to prepare the valuation report.

As noted above, Hydro One provided a direct reconciliation between the benefit forecast prepared by Willis Towers Watson and what it is seeking to recover in the test period in respect to its OPEB costs Therefore OEB staff accepts the test period OPEB costs, however notes that they may be subject to change pending the outcome of Issue 11[392] in this proceeding.

OEB staff also accepts the 2020 pension contribution amounts pending a confirmation from Hydro that reconciles the pension contribution amounts in Table 29 above with its December 31, 2018 valuation.[393] OEB staff notes that there is currently nothing on the record of this proceeding that directly reconciles the test period pension contribution amount to Hydro One's latest pension valuation. Although, Hydro One confirmed during the oral hearing that its 2020 pension contributions are derived directly from its valuation,[394] OEB staff recommends that Hydro One clarify this matter in its reply submission. To that end, OEB staff requests that Hydro One provide, as part of its reply submission, a table similar to that provided in its evidence[395] that reconciles to its 2020 pension contribution amount per its December 31, 2018 pension valuation.

G: RATE BASE & COST OF CAPITAL

18. Are the amounts proposed for rate base (including the working capital allowance amounts) reasonable?

Background

Hydro One noted that it determines transmission rate base based on the net book value of fixed assets which are forecast on a mid-year average basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service, including the

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[392] Re: the appropriateness of the capitalization of OPEBs
[393] And with the amount presented in undertaking J4.09.
[394] Transcript Volume 6, p. 28, lines 3-6.
[395] Exhibit F, Tab 5, Schedule 1, Table 2.

forecasted in-service additions for a year, minus accumulated depreciation. Hydro One submitted that these amounts had been correctly determined and are appropriate.

Hydro One further submitted that its depreciation expense is appropriate for the reasons set out under Issue 16 and the planned in-service additions are appropriately forecasted based on its proposed capital expenditures, which as explained under Issue 9 were derived through a robust investment planning process that underpins the TSP.

Hydro One argued that its working capital allowance amounts are also appropriate as the underlying methodology is supported by Navigant's updated lead-lag study which examined the working capital requirements of Hydro One's transmission business.[396] Hydro One added that in accordance with the OEB's direction in the previous cost of service transmission Decision,[397] it has provided a comparison with the prior study to show material changes in study results, which are attributable to an overall increase in revenue lag.

Hydro One concluded that for the reasons discussed above and in the application, its proposed rate base amounts are appropriate and should be used to determine revenue requirement for the 2020-2022 test period.

OEB Staff Submission

OEB staff submits that Hydro One's proposed rate base is reasonable subject to the adjustments proposed under Issue 9.

OEB staff notes that the working capital allowance proposed by Hydro One is based on an update of the prior Navigant study for which the OEB had accepted the results.[398] OEB staff further notes that the stated impact of implementing the current study results, as compared to the previously approved study are an increase in cash working capital of $6.5 million, or an increase in revenue requirement of approximately $0.49 million per year,[399] which is below Hydro One's materiality threshold. OEB staff accordingly accepts the proposed working capital allowance as reasonable.

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[396] Exhibit. C-5-1, Attachment 1
[397] EB-2016-0160
[398] EB-2009-0096 *Decision with Reasons.*
[399] Exhibit. C Tab 5, Schedule. 1, p. 4.

19. Is the proposed cost of capital (interest on debt, return on equity) and capital structure reasonable?

Background

Hydro One stated that its deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base. Hydro One further stated that this capital structure is consistent with the approved structure in its last transmission rebasing revenue requirement proceeding, as well as the capital structure approved in the most recent distribution rates proceeding and OEB policy. Hydro One noted that the 60% debt component consists of 56% long-term debt and 4% deemed short-term debt.

Hydro One stated that it had calculated its long-term debt rate to be 4.33% for 2020 to 2022 based on the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2020. Hydro One added that the 2020 revenue requirement had been reduced due to 2019 actual debt issuances and the updated cost of capital parameters issued by the OEB in October 2019.

Hydro One stated that the deemed short-term debt rate of 2.75% was also updated by Hydro One for the 2020 to 2022 test years based on the 2020 deemed short-term debt rate issued by the OEB in October 2019.

Hydro One further stated that an ROE of 8.52% had been used for the equity component of the cost of capital and that this had also been based on the OEB’s most recent cost of capital parameters.

Hydro One concluded that its proposed costs of capital and capital structure are reasonable and consistent with what had been approved in previous OEB decisions and, as such, should be accepted by the OEB.

OEB Staff Submission

OEB staff submits that Hydro One’s proposed capital structure and cost of capital are in accordance with OEB policy and with the OEB’s most recent transmission and distribution decisions for Hydro One and accordingly should be accepted by the OEB.

H: LOAD & REVENUE FORECAST

20. Is the load forecast methodology (including consideration of CDM impacts) and the resulting load forecast appropriate?

Background

Hydro One is forecasting a 3.9% reduction of the 2020 Ontario demand forecast as compared to the OEB-approved 2018 load forecast. This reduction is composed of a 3.5% reduction in the approved 2018 forecast, primarily driven by the expanded Industrial Conservation Initiative (ICI), and a further 0.4% reduction due to slower economic growth and Conservation Demand Management (CDM) initiatives.[400] There is also a further 0.7% and 0.8% reduction anticipated for 2021 and 2022 respectively.

Hydro One explained that the 2017 actual load was 3.3% lower than the 2017 OEB approved load forecast and 2018 actual load was 3.5% lower than the 2018 OEB approved load forecast.[401] Hydro One explains the expanded ICI program is the primary reason for the reduction in the 2017 and 2018 load forecast compared to actuals.[402] The ICI program was expanded in September 2016 lowering the 3 MW monthly peak demand threshold to 1 MW and further expansion of the program in April 2017 lowered the threshold to 0.5 MW.

OEB Staff Submission

OEB staff submits that the one time reduction of 3.5% in 2020 compared to the approved 2018 forecast is reasonable based on the expanded ICI program explanation.

OEB staff notes that between 2017 and 2020 there has been a step-wise increase in the load forecast before deducting impacts from embedded generation and CDM. This is an average 315 MW increase, each year which has precipitously dropped to a 30 MW and 13 MW decrease in 2021 and 2022 respectively.[403] OEB staff further notes that the 2020-2022 economic forecast shows growth, albeit at a slower pace compared to previous years, as identified by the expected growth rates of Gross Domestic Product, population

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[400] Exhibit E, Tab 3, Schedule 1, pp. 21; Oral Hearing Transcript, Vol. 7, pp. 144-147
[401] Exhibit E, Tab 3, Schedule 1, pp. 21;
[402] Exhibit E, Tab 3, Schedule 1, pp. 21; Oral Hearing Transcript, Vol. 7, pp. 145
[403] Exhibit E, Tab 3, Schedule 1, pp. 20, Table 3

growth, housing starts, commercial floor space and industrial production from 2019 onwards.[404]

OEB staff submits that this continuing growth is inconsistent with the precipitous drop in Hydro One's load forecast before deducting the impacts of embedded generation and CDM in 2021 and 2022.

Hydro One's evidence shows that the load impact of CDM has been growing at approximately 300 MW annually from 2017 to 2020 reducing to approximately 100 MW annually from 2021 to 2022.[405] In other words, CDM is forecasted to slow down in 2021 and 2022. Hydro One states that the forecasted CDM impacts are consistent with the 2013 LTEP and the latest figures from IESO.[406]

OEB staff further submits that the reductions of 0.4%, 0.7% and 0.8% in 2020, 2021 and 2022 respectively are not appropriate and should be reduced to 0.0% from 2020 to 2022 for the reasons discussed above relating to economic growth and decreasing CDM forecast.

21. Are Other Revenue (including export revenue) forecasts appropriate?

Background

Hydro One's historical actual 2015-2018 external revenue and forecasted 2019-2022 external revenue is shown in the following table.[407]

[404] Exhibit E, Tab 3, Schedule 1, pp. 5-6
[405] Exhibit E, Tab 3, Schedule 1, pp. 8, Table 2
[406] Exhibit E, Tab 3, Schedule 1, pp. 8
[407] Exhibit E, Tab 2, Schedule 1, pp. 2, Table 1

Table 30: External Revenue ($ Millions)

	Actual	Actual	Actual	Actual	Bridge	Test Year	Forecast Year	Forecast Year
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Secondary Land Use	$ 34.3	$ 24.9	$ 20.1	$ 25.6	$ 17.6	$ 17.9	$ 18.2	$ 18.5
Station Maintenance	$ 9.5	$ 6.2	$ 3.9	$ 4.6	$ 4.0	$ 4.0	$ 4.0	$ 4.0
Engineering & Construction	$ 0.4	$ 0.2	$ 0.3	$ 0.1	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Other External Revenues	$ 10.1	$ 11.0	$ 11.2	$ 9.1	$ 9.4	$ 9.2	$ 10.3	$ 9.4
Total	$ 54.3	$ 42.3	$ 35.5	$ 39.4	$ 31.3	$ 31.4	$ 32.7	$ 32.2

Hydro One has explained the significant decrease in the test year forecast from the 2015 to 2018 actual levels by noting that it manages the Provincial Secondary Land Use Program on behalf of the province. Hydro One states that in the actual years the external revenue from secondary land use was due to unbudgeted one-time transactions.[408] Hydro One argues that these transactions are difficult to forecast as third party negotiations are involved and the outcomes and timelines are out of Hydro One's control.[409]

All other revenues, station maintenance, engineering & construction and other external revenue, are forecasted to remain relatively flat compared to previous years.

Hydro One has confirmed that all external revenue sources in Table 30 have variance accounts and proposes continuance of these accounts in 2020 through 2022.[410]

OEB Staff Submission

OEB staff submits that the forecasted 2020- 2022 external revenues are reasonably explained. OEB staff further submits that the associated variance accounts for external revenues should be approved, as any variance against the forecast is symmetrically treated.

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[408] Exhibit E, Tab 2, Schedule 1, pp. 4
[409] VECC IR #19
[410] LPMA IR #10

I: DEFERRAL/VARIANCE ACCOUNTS

22. Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Background

Hydro One is seeking disposition of its December 31, 2018 audited deferral and variance account balances adjusted for dispositions approved by the OEB during 2019. A summary of the accounts is provided in the following table:

Table 31
Disposition of December 31, 2018 DVA Account Balances (in $M)

Account	Description	Principal[411]	Interest[412]	Total
2405	Excess Export Service Revenue	$4.72	$0.07	$4.79
2405	External Secondary Land Use Revenue	($9.98)	($0.45)	($10.43)
2405	External Station Maintenance, E&CS and Other External Revenue	$4.43	$0.08	$4.51
1592	Tax Rate Changes		$0.00	$0.00
2405	Rights Payments	$2.31	$0.08	$2.39
2405	Pension Costs Differential	($4.17)	($0.31)	($4.48)
1508	Long-Term Transmission Future Corridor Acquisition and Development		$0.00	$0.00
1508	LDC CDM and Demand Response Variance Account	$22.68	$0.94	$23.62
2405	External Revenue – Partnership Transmission Projects Account		$0.00	$0.00
1508	Waasigan Transmission Deferral Account	$0.82	$0.05	$0.87
1508	OEB Cost Differential Account	($0.11)	($0.02)	($0.13)
2405	In-Service Capital Additions Variance Account	($0.64)	($0.01)	($0.65)
	TOTAL	**$20.06**	**$0.43**	**$20.49**

Hydro One has confirmed that all of the regulatory accounts presented above have been established consistent with the requirements of the OEB's Accounting Procedures

[411] Exhibit H, Tab 1, Schedule 5, Attachment 1(excel continuity schedule)
[412] *Ibid*

Handbook and any subsequent direction provided by the OEB. Hydro One has further confirmed that the OEB's prescribed rates were used for purposes of calculating the carrying charges on the principal balances, and that no adjustments have been made to deferral and variance account balances that were previously approved by the OEB on a final basis.[413]

Hydro One provided detailed descriptions as to the composition of the balances in each account as part of its evidence[414] of the current application.

Hydro One is seeking disposition of its December 31, 2018 deferral and variance account balances over a three year period.[415]

OEB Staff Submission

Based on the evidence provided on the record and Hydro One's responses to applicable interrogatories, OEB staff submits it has no concerns with the proposed disposition of the December 31, 2018 deferral and variance account balances.

Other Deferral and Variance Account Not Being Disposed

Background

The following table summarizes the accounts as at December 31, 2018 for which Hydro One is not seeking disposition of in its current application:

[413] Exhibit H, Tab 1, Schedule 1, p. 1-2.
[414] Exhibit H
[415] Exhibit H, Tab 1, Schedule 1, p. 2.

Table 32
2018 Deferral and Variance Account Balances Not Being Disposed (In $M)

Account	Description	Principal[416]	Interest[417]	Total
1508	OPEB Cost Deferral	$22.38	$0.61	$22.99
1508	East-West Tie Deferral Account (Tracking only)	$15.79	$0.00	$15.79
1508	SECTR Deferral Account (Tracking only)	$54.32	$0.00	$54.32
1522	OPEB Asymmetrical Carrying Charge Account			
	TOTAL	**$92.49**	**$0.61**	**$93.10**

Hydro One has provided detailed explanations as to why the above accounts are not being disposed as part of the evidence filed in the current proceeding.[418]

In particular, Hydro One is not seeking disposition of the East West Tie and SECTR accounts on the basis that these are both currently only tracking accounts.[419]

In addition, Hydro One has not proposed to dispose of the balance within the OPEB Cost Deferral account as it is tied to the outcome of Issue 11 in the current proceeding.[420]

In regard to the OPEB Asymmetrical Carrying Charges account, this account is effective from January 1, 2018 and was established on a generic basis through the OEB's report on the Regulatory Treatment of Pension and OPEB Costs (the OEB Report) that was released on September 14, 2017. The account tracks the differential between Hydro One's OPEB accrual amount recovered in rates and its actual cash payments made in respect to OPEBs for the purpose of calculating an asymmetrical carrying charge in favour of ratepayers on the cumulative differential tracked within the account (i.e. carrying charges will only apply when the cumulative forecast accrual amount exceeds the cumulative actual cash payments).[421]

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[416] Exhibit H, Tab 1, Schedule 5, Attachment 1(excel continuity schedule)
[417] *Ibid*
[418] Exhibit H
[419] Exhibit H, Tab 1, Schedule 1, p. 14-15.
[420] Exhibit H, Tab 1, Schedule 1, p. 15, and Updated Exhibit H, Tab 1, Schedule 2, p. 8-14.
[421] This account only tracks the differential associated with OPEB costs. Pension costs are excluded because Hydro One recovers its pension costs on a cash basis and therefore no differential exists.

Hydro One is proposing an alternate methodology for determining the forecast accrual amount it recovers in rates compared to the default methodology prescribed in the OEB Report. Based on its alternate methodology, Hydro One has determined that no carrying charges were payable to ratepayers in 2018 (as actual cash payments exceeded the accrual amount) and therefore the balance in the OPEB Asymmetrical Carrying Charges account as at December 31, 2018 is zero. As such, disposition of this account is not being requested for 2018.[422]

Furthermore, based on its alternate methodology, Hydro One has also forecast that there will likely be no carrying charges payable to its ratepayers from the OPEB Asymmetrical Carrying Charges account for the period 2019-2022.[423]

The default methodology prescribed in the OEB Report assumes that the total gross accrual cost as determined by an actuarial valuation is what is recorded in a utility's total OM&A expense and hence represents the forecast accrual amount that is recovered in rates for a given year. However, the OEB Report also states:

> If a utility capitalizes a material portion of its total pension and OPEB accrual costs, and there is sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately from those that are expensed, any party may propose an enhanced methodology for determining the reference amount (i.e. the forecast accrual amount).[424]

As Hydro One capitalizes a significant portion of its OPEB costs, it is proposing an alternate methodology to determine the forecast accrual amount in rates. The alternate methodology is based on the sum of the following components of its annual revenue requirement: the OM&A expense portion of its forecast annual OPEB accrual cost, plus the depreciation on its capitalized OPEB costs that were capitalized to rate base from January 1, 2018 and forward, plus the annual amortization of costs recorded in the OPEB Cost deferral account (which is dependent on the OEB's findings in Issue 11 of this proceeding).[425]

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[422] Exhibit H, Tab 1, Schedule 1, p. 16, and Exhibit H, Tab 1, Schedule 2, p. 8-14.

[423] Exhibit I, Tab 1, Schedule 222, response e)

[424] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017, p. 20.

[425] Exhibit H, Tab 1, Schedule 2, p. 11, and Exhibit I, Tab1, Schedule 222, response c), Argument-in-Chief p. 78.

OEB staff further notes that in its recent distribution rate case[426] Hydro One agreed to defer the determination of this issue (i.e. pertaining to its use of an alternate methodology for purposes of tracking amounts in the OPEB Asymmetrical Carrying Charges account) to the current transmission proceeding so that a decision on this matter can be made for both the distribution and transmission businesses. The alternate methodology proposed is consistent for both the transmission and distribution businesses.

OEB Staff Submission

OEB staff submits that it has no concerns with not disposing of the of the East West Tie and SECTR accounts on the basis that both accounts are tracking accounts only that provide visibility to the OEB as to the costs associated with both projects.

In regard to the OPEB Cost Deferral Account, OEB staff submits that the balance in this account may be disposed of in the current proceeding depending on the OEB's findings on Issue 11. In particular, there is a potential outcome to that issue where the OEB disallows Hydro One's proposals to either continue capitalization of the impacted costs or to continue to use the OPEB Deferral Account going forward to capture the impacted costs. Hydro One has indicated that if such an outcome were to occur, then it intends to dispose of the 2018 audited balance within this account as part of the current proceeding.[427] OEB staff further submits that if Hydro One seeks disposition of the December 31, 2018 balance in this account, then it will need to amend its DVA disposition request as part of the draft rate order in the proceeding.

With respect to the OPEB Asymmetrical Carrying Charges account, OEB staff does not support Hydro One's proposed alternate methodology because it understates the forecast accrual amount that it is actually recovering in rates related to its OPEB costs. By doing so, it effectively minimizes the return that ratepayers will receive in the form of asymmetrical carrying charges on the differential tracked within the account.

The understatement occurs because Hydro One's alternate methodology proposes to only recognize the depreciation associated with the OPEB costs that have been capitalized to rate base from January 1, 2018 (the effective date of the account) as part of the calculation of the forecast accrual amount in rates. It fails to take into account the depreciation associated with OPEB costs that have been capitalized pre January 1, 2018, but still continue to form part of rate base, and hence will form part of the annual depreciation that Hydro One will recover in rates going forward (after January 1, 2018).

[426] EB-2017-0049

[427] Exhibit I, Tab 1, Schedule 206, response b).

The intent of the OEB Report is to provide ratepayers with a return on amounts they have effectively lent a utility in the rates of a given year related to pension and OPEB costs. The OEB makes this very clear through the following excerpts:

> Where pension and OPEB amounts collected in rates are higher than payments made by the utility, current ratepayers are in effect lending money to the utility to fund future obligations.[428]
>
> ………Therefore, where the amount collected in rates exceeds the monies paid out by a utility for its pension and OPEB plans, ratepayers should be paid a return on the money they have "lent" the utility.[429]

Nowhere in the OEB Report does the OEB define or put a limit on what constitutes "the amount collected in rates" because it expects that to be based on what a utility actually gets approved to recover for a given year. Hydro One's alternate methodology does not result in a true representation of what it will recover because it omits a potentially material component of depreciation associated with its capitalized OPEB costs. OEB staff submits that such an outcome would not be fair to ratepayers and is inconsistent with the spirit of the OEB Report.

Hydro One contends that the following excerpt from the OEB Report supports its proposed alternate methodology.[430]

> This account will track the differences between the forecast accrual amounts recovered in rates and the actual cash payments made for both pension and OPEBs in one account, on a go-forward basis from the date the account is established. The account will not capture differences that occurred in the past…..

OEB staff' submits that the above statement is stating that for purposes of implementing the requirements of the OEB Report, the OEB will only require a utility to quantify and track the difference between the OPEB amounts it recovers in rates and the actual cash payments it made starting from the effective date of the new account. The account will not track this variance for historical years.

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[428] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017, p. 10
[429] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017, p. 11
[430] Exhibit I, Tab 1, Schedule 222, response c)

To that end, OPEB costs capitalized to rate base are not recovered in rates until they are depreciated. Therefore OEB staff submits that any undepreciated capitalized OPEB cost that is in rate base as of January 1, 2018 should be subject to the new variance account as it will be recovered in rates after January 1, 2018 (and therefore should be included as part of the calculation of the reference accrual amount that a utility recovers in rates of a given year).

OEB staff submits that if Hydro One is permitted to use an alternate methodology for purposes of tracking amounts in the variance account, it should be based on the sum of the following components:

a) The portion of the annual OPEB costs that is expensed to OM&A.
b) The annual depreciation associated with the cumulative undepreciated capitalized OPEB costs in rate base.
c) The annual amortization of costs recorded in the OPEB Cost deferral account, subject to the OEB approving the continued use of that account as part its findings in Issue 11 of this proceeding.

OEB staff requested that Hydro One provide a calculation consistent with the above methodology, however Hydro One indicated that it was unable to provide a reasonable estimate of annual depreciation associated with its cumulative undepreciated capitalized OPEB costs in rate base (component b) above) because the OPEB amounts capitalized in prior periods are not identifiable.[431] Therefore, it is also not possible to determine how material the impact is of excluding these amounts from the calculation of the accrual OPEB amount that Hydro One recovers in its rates.

In light of this, OEB staff submits that Hydro One should be ordered by the OEB to follow the default methodology prescribed in the OEB Report as, in OEB staff's view, it is the only viable and fair option that remains. After all, the intent of allowing utilities to propose an alternate methodology was so that the OEB can consider a more precise calculation of the accrual amount recovered in rates for those utilities that capitalize a significant portion of their pension and OPEB costs. If Hydro One is unable to provide this level of precision, then in OEB staff's view the default approach should apply.

Hydro One has already provided the following estimate of the carrying charges that would be payable to its ratepayers under the default methodology of the OEB Report:[432]

[431] Undertaking JT – 2.5 and Argument-in-Chief, p. 79.
[432] Exhibit I, Tab 1, Schedule 222, response e)

Table 33
Forecast Carrying Charges Based on the Default Methodology

(In M$)	2018	2019	2020	2021	2022	Total
Carrying Charges	$0.8	$1.5	$2.3	$3.1	$3.8	$11.5

OEB staff further submits that if Hydro One is ordered to follow the default methodology for purposes of this variance account, then the related carrying charges for 2018 must be recorded in the variance account as at December 31, 2018.

23. Are the proposed new deferral and variance accounts appropriate?

Background

Hydro One is requesting the following new deferral and variance accounts:

Table 34
New Deferral and Variance Accounts Requested

Account	Status
CCRA True-up Variance Account	New
ESM Deferral Account	New
Foregone Transmission Revenue Deferral Account	New
Transmission Revenue Requirement Variance Tracking Account	New

Hydro One is proposing to establish a new variance account, called the CCRA True-up Variance Account, to track the difference between components of revenue requirement and actual results related to load true-ups performed in accordance with section 6.5.3 of the Transmission System Code. Hydro One states that it has identified a number of significant forecasting risks that are beyond its control therefore resulting in the need for the requested variance account.[433] Hydro One has filed a draft accounting order in support of the proposed new account.[434]

[433] Exhibit C, Tab 1, Schedule 7
[434] Exhibit H, Tab 1, Schedule 2, Attachment 4

Hydro One is proposing to establish a new asymmetrical ESM Deferral Account effective January 1, 2020 to record any over-earnings realized during any year of the three-year term of the current Custom IR application (2020-2022). The account will record (to return to ratepayers) 50% of any earnings that exceed the regulatory return on equity approved in the current application by more than 100 basis points in any year of the three-year term.[435] It is consistent with the mechanism approved in Hydro One's last distribution rates proceeding. Hydro One has filed a draft accounting order in support of the proposed new account.[436]

Hydro One is proposing to establish a Foregone Transmission Revenue deferral account to capture foregone revenue from January 1, 2020 to the date when the approved 2020 UTRs are reflected in the revenue earned by Hydro One transmission. A similar account was approved in Hydro One's 2017-2018 transmission rates proceeding. However the account was discontinued as part of the OEB's April 25, 2019 Decision in EB-2018-0130. Therefore Hydro One is now requesting it again as part of its current proceeding.[437] Hydro One has filed a draft accounting order in support of the proposed new account.[438]

In its Argument-in-Chief, Hydro One has also requested OEB approval to establish a variance account, effective January 1, 2017, that will track the difference between Hydro One's regulatory income tax revenue requirement underlying its approved transmission rates and what that transmission revenue requirement would have been if its appeal before the Divisional Court related to the sharing of tax benefits from its recent IPO is successful.

OEB Staff Submission

Based on the evidence provided on the record, OEB staff has no concerns with approving the establishment of the CCRA True-up Variance Account, ESM Deferral Account, and the Foregone Revenue Deferral Account.

OEB staff does have concerns with Hydro One's proposed Transmission Revenue Requirement Variance Tracking Account which is discussed further as part of OEB staff's submission on Issue 15.

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[435] Exhibit H, Tab 1, Schedule 2, p. 7
[436] Exhibit H, Tab 1, Schedule 2, Attachment 3
[437] Argument-in-Chief, p. 117-118
[438] Exhibit H, Tab 1, Schedule 2, Attachment 1

Request to Continue Deferral and Variance Accounts

Background

Hydro One is requesting OEB approval to continue using the following deferral and variance accounts:

Table 35
Continuation of Deferral and Variance Accounts

Account	Status
Excess Export Service Revenue	Continue
External Secondary Land Use Revenue	Continue
Tax Rate Changes	Continue
Rights Payments	Continue
Pension Costs Differential	Continue
Long-Term Transmission Future Corridor Acquisition and Development	Continue
LDC CDM and Demand Response Variance Account	Continue
External Revenue – Partnership Transmission Projects Account	Continue
Waasigan Transmission Lin Deferral	Continue
In-Service-Capital Additions Variance	Continue
OPEB Cost Deferral	Continue
East-West Tie Deferral Account (Tracking only)	Continue
SECTR Deferral Account (Tracking only)	Continue
OPEB Asymmetrical Carrying Charge Account	Continue

Hydro One has proposed a modification to its In-Service-Capital Additions Variance account. In particular, it has proposed to exclude verifiable productivity savings from the calculation of this account to ensure that true productivity savings are incented throughout the term of the Custom IR application.[439] Verifiable productivity gains refer to additional capital-related productivity gains beyond those already identified and included within the current revenue requirement (both specific productivity savings and progressive productivity savings).

[439] Argument-in-Chief, p. 119.

OEB Staff Submission

OEB staff has no concerns with the continuation of the deferral and variance accounts list in Table 35 above, subject to the following comments related to certain accounts.

As noted previously, the continuance of the OPEB Cost Deferral account is dependent on the OEB's findings for Issue 11 of this proceeding. In the event that the OEB finds that continuation of the OPEB Cost Deferral account is not appropriate, then OEB staff submits that the OEB should also order that this account be closed upon disposition of the current balance within the account.

In regard to the In-Service-Capital Additions account, Hydro One's proposed modification to exclude any verifiable productivity savings (as defined above) from the calculation of the balance that flows to the account. Accepting the modification means that the revenue requirement impact associated with the verifiable productivity savings would flow entirely to the benefit of Hydro One's shareholder over the term of the Customer IR application. Hydro One argues that such an outcome is appropriate on the basis that it incents incremental findings of productivity gains throughout the Custom IR period without penalizing the utility for finding these savings.

In addition to lowering the rate base that will be included in future transmission rate applications, the incremental productivity gains would also reduce the value of the actual in-service-additions achieved over the term of the current Custom IR application. Lower in-service-additions could then result in a claw-back, through the In-Service Capital Additions variance account, of some of the revenue requirement benefits that Hydro One realizes from the incremental productivity gains.

OEB staff submits that Hydro One's modification introduces significant regulatory burden to the process of assessing the prudence of the disposition amount in the account. In particular, it will be very difficult to differentiate between what is a productivity gain as opposed to savings that result from such things as proper due diligence, inflated forecasts, and changes to the scope of a project as has been discussed under issue 6.

OEB staff accordingly submits that the OEB should reject Hydro One's proposed modification to the In-Service-Capital Additions variance account. OEB staff submits that the account should be continued using the same approach that was approved in the last transmission rates application.[440]

[440] EB-2016-0160

As part of the draft rate order process in this proceeding, OEB staff further submits that Hydro One should be required to file an updated accounting order for its In-Service-Capital Additions variance account. The accounting order should be prepared using wording that is consistent with the In-Service-Capital Additions variance account that was approved in Hydro One's last transmission rates application.[441]

J: COST ALLOCATION

24. Is the transmission cost allocation proposed by Hydro One appropriate?

Background

Hydro One continues to follow the OEB-approved methodology from the last transmission rebasing application to allocate the transmission rates revenue requirement into three rate pools: Network, Line Connection and Transformation Connection. The rate pools are based on functional categories of assets and their associated costs.[442]

The derivation of the revenue required to be collected through transmission rates is based on Hydro One's proposed total revenue requirement offset by other revenues consisting of: external revenue, wholesale meter service revenue, regulatory assets, export transmission service revenue, and funding for low voltage switchgear credit.[443]

Hydro One proposed not to re-run the cost allocation model for the 2021 and 2022 test years, but rather to determine the rates revenue requirement by rate pool using the methodology approved for Hydro One's 2019 transmission[444] revenue cap adjustment.[445]

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[441] In addition to the variance associated with in-service additions over the application term, the wording of the approved accounting order in EB-2016-0160 also specifically made reference to capturing the impact on the approved transmission revenue requirement of a difference in the bridge-year in-service additions forecast in the application compared to the actual bridge-year additions (as that variance directly impacts the opening rate base balance for the test-year).
[442] Exhibit I1-1-1, filed 2019-06-19, page 2 of 3.
[443] *Ibid.*
[444] EB-2018-0130
[445] Argument in Chief, filed 2019-11-22, page 120 of 122.

OEB Staff Submission

OEB staff has no concerns with the proposed cost allocation approach for 2020-2022.

OEB staff notes that Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years. Specifically, Hydro One proposed to include energy storage facilities to the definition of billing demand for embedded generation.[446] Hydro One stated that the proposed changes in wording clarify and reflect Hydro One's interpretation of these definitions in the data provided to IESO for transmission billing purposes. Hydro One went on to state that[447]

> It is Hydro One's interpretation and practice to include customers with energy storage facilities and/or solar generators (the individual inverter with capacity is 1 MW or higher) in the data provided to the IESO for billing Line Connection and Transformation Connection customers on a gross load basis as per the approved UTR tariff. As discussed, in part (a), the proposed wording changes simply clarify and reflect Hydro One's interpretation. There will be no cost shifting as there will be no change in Hydro One's practice.

Hydro One does not consider energy storage facilities as a renewable energy source and asserted that its understanding is consistent with the definition under Section 2 of the *Electricity Act, 1998*.[448] OEB staff asked Hydro One as to whether it consulted with storage customers on this proposed wording. Hydro One responded that it did not. Hydro One noted that these wording changes are intended to clarify and reflect Hydro One's interpretation and current practice and that customers will not be impacted by these changes.[449]

The current UTR Schedules, and the corresponding Terms and Conditions, do not mention energy storage facilities. Hydro One's practice is to effectively impose gross load billing on transmission customers with energy storage facilities behind their meters based on a 1 MW threshold for non-renewable generation rather than the 2 MW threshold that applies to renewable generation.

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[446] Exhibit JT 2.34-Q18, filed 2019-08-21, page 1 of 2.
[447] Exhibit I-01-225, filed 2019-08-02, page 2 of 2.
[448] Exhibit J9.3, filed 2019-11-11, page 1 of 1.
[449] Exhibit I-01-225, filed 2019-08-02, page 2 of 2.

This may be Hydro One's practice, but it is not clear that this has been considered by the OEB, and Hydro One has acknowledged that it has not consulted with storage customers in this regard. As Hydro One notes, the definition of billing demand for the line and transformation connection services and embedded generation in the current UTR schedule was last updated in a 2005 proceeding.[450]

OEB staff is concerned that Hydro One is proposing to formalize its practice with regard to energy storage facilities by amending the Terms and Conditions of the UTR schedule in the absence of, at a minimum, consultation with potentially affected customers and further consideration by, and direction from the OEB. OEB staff suggests that there may also be policy considerations around the question of the appropriate treatment of energy storage facilities that would warrant further industry consultation and OEB direction. In its reply submission, Hydro One should clarify whether the OEB has previously approved Hydro One's current practice regarding storage facilities. However, OEB staff cannot at this time support the proposed amendments to the Terms and Conditions of the UTR Schedules.

K: EXPORT TRANSMISSION SERVICE RATES

25. Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

Background

The current Export Transmission Service (ETS) rate of $1.85/MWh was settled and approved by the OEB in Hydro One's 2015-2016 transmission application.[451] A cost allocation study prepared by Elenchus Research Associates Inc. (Elenchus) was filed as part of the 2015-2016 proceeding. Hydro One confirmed that parties to the 2015-2016 proceeding agreed on the ETS rate on the understanding that the methodologies, assumptions, and scenarios used in the Elenchus study do not have precedential value and may be challenged in subsequent proceedings.[452]

Using the cost allocation study recommended by Elenchus in the 2015-2016 proceeding, Hydro One calculated an ETS rate of $1.25/MWh for 2020. However, Hydro One

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[450] Exhibit I-01-225, filed 2019-08-02, page 2 of 2, part c.
[451] EB-2014-0410
[452] Oral Hearing Transcript, Volume 8 Revised, page 146.

proposes to continue using the current ETS rate because "a decrease in the ETS rate will negatively impact the transmission rates that Ontario customers pay and could be perceived as benefiting customers in neighbouring jurisdictions at the expense of Ontario consumers."[453]

Hydro One confirmed that the two key reasons for the decrease in the calculated ETS rate compared to the 2015 study were a decrease in Hydro One's OM&A costs from 2015 to 2019, and an increase in forecast export in MWh.[454]

For the purpose of allocating capital costs between domestic and export customers, assets were organized into three categories: assets dedicated to domestic customers, assets dedicated to export customers, and shared assets. Hydro One confirmed that using the recommended methodology, capital costs related to shared assets are not being allocated to export customers.[455] Hydro One referred to Elenchus' explanation that export service is being considered as an interruptible service and Hydro One's network transmission system was built only to meet the needs of domestic customers.[456]

Hydro One noted the following deficiencies in the recommended cost allocation study:[457]

- Rather than deriving a methodology to allocate shared assets between domestic and export customers, as a typical cost allocation study would do for shared assets, the recommended study excluded allocating shared capital costs to export customers completely even though those assets do serve export customers
- No jurisdictional review was done such that one can understand how ETS rates are determined in other jurisdictions

Hydro One noted that in many cases, shared costs are typically allocated to all rate classes that use the assets.[458] Furthermore, Hydro One confirmed that if shared capital costs were allocated to export customers, the resulting ETS rate would likely be much higher than $1.85/MWh.[459]

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[453] Exhibit I2-4-1, filed 2019-06-19, page 3 of 4.
[454] Oral Hearing Transcript, Volume 8 Revised, pp. 147-148.
[455] Oral Hearing Transcript, Volume 8 Revised, page 149.
[456] Oral Hearing Transcript, Volume 8 Revised, page 150.
[457] Oral Hearing Transcript, Volume 9 Revised, pp. 5-10.
[458] Oral Hearing Transcript, Volume 9 Revised, page 11.
[459] Oral Hearing Transcript, Volume 9 Revised, page 12.

OEB Staff Submission

OEB staff supports Hydro One's proposal to maintain the ETS rate at the current level of $1.85/MWh in this application considering the deficiencies that exist in the recommended cost allocation study.

OEB staff notes that the OEB directed Hydro One to prepare a cost allocation study including a proposal for an appropriate cost-based ETS rate in its decision on 2013 ETS rates.[460] The current ETS rate of $1.85/MWh arose from the settlement agreement for the 2015-2016 transmission application and has been in place for five years.[461] OEB staff submits that Hydro One should provide a proposal for a cost-based ETS rate in its next rebasing application, with supporting calculations allocating shared capital costs to export customers.

ETS Revenues

Background

Hydro One's ETS revenues are calculated using the proposed rate of $1.85/MWh and the three year historical rolling average volume of electricity exported from Ontario.[462] Hydro One confirmed that this methodology has been approved since 2010.[463]

OEB Staff Submission

OEB staff submits that the proposed ETS revenues are appropriate.

-All of which is respectfully submitted-

[460] EB-2012-0031.
[461] Oral Hearing Transcript, Volume 9 Revised, page 3.
[462] Exhibit I2-4-1, filed 2019-06-19, pp. 3-4 of 4.
[463] Oral Hearing Transcript, Volume 9 Revised, page 14.