Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

August 21, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: **Toronto Hydro-Electric System Limited (Toronto Hydro)**
Application for 2020-2024 Rates
OEB Staff Submission
Board File Number: EB-2018-0165

In accordance with the Decision on Confidentiality and Procedural Order No. 4, please find attached OEB staff's submission in the above noted proceeding. Toronto Hydro and all intervenors have been copied on this filing.

Yours truly,

Original Signed By

Lawrie Gluck
Case Manager

cc: All parties in EB-2018-0165

Ontario

ONTARIO ENERGY BOARD

OEB STAFF SUBMISSION

Toronto Hydro-Electric System Limited

2020 – 2024 Rates Application

EB-2018-0165

August 21, 2019

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1. Introduction

Toronto Hydro-Electric System Limited (Toronto Hydro) filed a five-year Custom Incentive Rate-setting (Custom IR) application with the Ontario Energy Board (OEB) under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) (OEB Act), seeking approval for changes to its distribution rates, to be effective January 1, 2020 to December 31, 2024 (the Application).

The Application is supported by evidence filed on August 15, 2018 (and updated on September 14, 2018). A further application update was filed on April 30, 2019, which provided certain 2018 actual figures and updated certain 2019 and 2020-2024 amounts where the consequential impacts of 2018 actuals are material.[1] Toronto Hydro made further updates to the Application in its interrogatory responses regarding the application update. A summary of the updates that Toronto Hydro proposed to flow through to the Revenue Requirement Workform and cost allocation model at the draft rate order stage of the proceeding is shown in Undertaking J1.2, which was updated after the conclusion of the oral hearing.[2]

Toronto Hydro is seeking approval to set its 2020 distribution rates on a cost of service basis. Toronto Hydro is also seeking approval of a Custom Price Cap Index (CPCI) framework to set distribution rates for the period January 1, 2021 to December 31, 2024.[3]

Over the 2020-2024 Custom IR term, Toronto Hydro is seeking to recover in rates, through its proposed CPCI formula, a base revenue requirement of $4,192.6 million (the CPCI funded revenue requirement).[4,5] This compares to an approved CPCI funded

[1] Exhibit U / Tab 1A / Schedule 2 / p. 1.
[2] Updated Undertaking J1.2 / July 31, 2019 / p. 1.
[3] Exhibit 1B / Tab 4 / Schedule 1 / pp. 1-2.
[4] Undertaking J1.8. The CPCI funded revenue requirement set out here, based on Undertaking J1.8, includes the updates discussed in the original filing of Undertaking J1.2 (July 2, 2019). The update to Undertaking J1.2 (July 31, 2019) includes an increase to the 2020 revenue requirement of $0.2 million related to the one-time application costs, which is not reflected here.
[5] Note that based on the original pre-filed evidence, prior to a number of updates being made to both capital-related and non capital-related revenue requirement, the proposed CPCI funded base revenue requirement was $4,254.6 million for 2020-2024 (1B-Staff-23 / p. 1). The proposed CPCI funded base revenue requirement has reduced by approximately $62 million due to the updates made throughout the proceeding.

revenue requirement for the 2015-2019 period of $3,511.3 million.[6] This represents an increase of $681.3 million (or 19.4%).

The proposed monthly distribution (sub-total A) bill impacts for typical residential and GS < 50 kW customers are as follows[7]:

Table 1
Bill Impacts (Sub-total A)

	2020	2021	2022	2023	2024	Average
Residential	$0.54 (1.3%)	$1.37 (3.2%)	$1.07 (2.5%)	$1.89 (4.2%)	$1.83 (3.9%)	$1.34 (3.0%)
Residential (w/ Rate Riders)	-$3.58 (-8.1%)	$1.37 (3.4%)	$1.07 (2.5%)	$1.89 (4.4%)	$1.83 (4.1%)	$0.52 (1.1%)
GS < 50 kW	$4.07 (4.0%)	$3.45 (3.3%)	$2.69 (2.5%)	$4.75 (4.2%)	$4.59 (3.9%)	$3.91 (3.6%)
GS < 50 kW (w/ Rate Riders)	-$5.82 (-5.4%)	$3.45 (3.4%)	$2.69 (2.5%)	$4.75 (4.4%)	$4.59 (4.0%)	$1.93 (1.7%)

OEB staff notes that Table 1 includes the latest bill impacts available on the record but does not include any of the updates set out in Undertaking J1.2, which reflect an overall reduction to the revenue requirement for the 2020-2024 Custom IR term. This means that the bill impacts in Table 1 are overstated.[8]

The Notice of Application was published in Toronto area newspapers in October 2018. The OEB held five in-person community meetings and an online webinar in November and December 2018. The OEB received 15 letters of comment. In addition, ten parties were granted intervenor status in the current proceeding.

The final issues list for this proceeding was approved on February 5, 2019.[9] The oral hearing for this proceeding commenced on June 27, 2019 and concluded on July 16, 2019. In total, there were 11 hearings days. Toronto Hydro filed its Argument-in-Chief on August 2, 2019.

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[6] 1B-Staff-23 / p. 2.
[7] Undertaking J7.4.
[8] Toronto Hydro in its argument-in-chief at page 6 references Undertaking J4.6 as the most up-to-date bill impacts, which OEB staff does not believe to be the case. OEB staff suggests Toronto Hydro clarify in its reply argument where the most up-to-date bill impacts can be located on the record.
[9] Decision on Issues List, Partial Decision on Confidentiality and Procedural Order No. 3 / February 5, 2019.

2. Summary of 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 2
Submission Summary

Issues	Estimated Impact on 2020-2024 Proposals
Custom IR Framework • Accept proposed use of OEB-approved distribution implicit price index (IPI) for inflation calculation and annually update inflation factor to the most current OEB-approved • Accept proposed use of base productivity factor of 0% as is currently approved for electricity distributors • Apply 0.45% stretch factor in CPCI formula • Apply 0.64% incremental stretch factor on capital in CPCI formula • Apply 0.25% growth factor in CPCI formula • The OEB should signal to Toronto Hydro that a request for the continuation of its proposed Custom IR framework, which includes a Capital factor, at the time of next rebasing[10] will not necessarily be approved. The OEB should advise Toronto Hydro that any future request for a Custom IR framework which includes a C-factor should include corrections to framework design issues and evidence verifying improved cost performance and need. In the absence of that evidence, Toronto Hydro should be encouraged to file a request for a standard price-cap Incentive Rate-setting Mechanism (IRM) (with the availability of Advanced Capital Module (ACM) and / or Incremental Capital Module (ICM) treatment for discrete capital projects) or an alternative Custom IR framework that does not include a C-factor cost recovery mechanism. • Earnings Sharing Mechanism (ESM) redesigned to record excess earnings based on net income (non-cumulative and asymmetrical) • Accept proposed Z-factor availability in accordance with OEB policy • Accept proposed off-ramp in accordance with OEB policy	$55 million reduction (revenue requirement)

[10] OEB staff uses "rebasing" and "cost-based" interchangeably in this submission.

Rate Base • Use average of monthly averages approach for rate base calculation • Permanent reduction to rate base for cost overruns on Copeland Phase 1	$23.5 million reduction (revenue requirement)
Capital Expenditures • Accept that Toronto Hydro's Distribution System Plan (DSP) is generally in accordance with filing requirements • Reductions related to Customer and Generation Connection capital budget • Reductions related to Planned System Renewal capital budget • Reductions related to Area Conversion capital budget • Control Operations Reinforcement program should not be approved for inclusion in rate base • Reduction related to Fleet and Equipment Services capital budget • Reduction related to Allowance for Funds used During Construction (AFUDC) • Customer Interruption Cost Study to be filed as part of next rebasing application • Customer-specific energy storage system projects are a non-distribution activity that appears to be allowed under section 71(3) of the OEB Act and should be accounted for separately from distribution activities. • Owning and operating electric vehicle (EV) charging stations is a non-distribution activity.	$246.8 million reduction (capital expenditures) $40-$60 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 for the current proceeding. However, a revised approach is required going forward.	In-service additions are impacted by OEB staff's capital expenditure argument
Load Forecast • Accept proposed load forecasting methodology and resulting load forecast. • The Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) as proposed will true-up CDM adjustments and the ESM account (as redesigned by OEB staff) should have a load true-up component going forward	N/A
Other Revenue • Increase other revenue (which offsets revenue requirement) for the gain on disposition of utility property	$1.8 million reduction (2020 revenue requirement) $9 million reduction (2020-2024 revenue requirement)
Operations, Maintenance & Administration (OM&A) Costs • Reduction related to Customer care OM&A budget • Reduction related to Asset and Program management OM&A budget	$9.4M reduction (2020 revenue requirement)

• Reduction related to one-time application costs • Reduction to OM&A budget to reflect Enterprise Resource Planning (ERP) related cost savings • Reduction to Compensation costs (impacts OM&A and capital)	$47 million reduction (2020-2024 revenue requirement)
Depreciation • Accept proposed depreciation forecasting methodology • Derecognition Variance Account should be closed • New useful life study for asset classes that have useful lives that are outside the Kinectrics range to be filed at the next rebasing	Depreciation expense is impacted by OEB staff's rate base and capital expenditure arguments
Payments in Lieu of Taxes (PILS) • Accept proposed updated PILs amount which reflects best estimate of impact of Bill C-97 (Capital Cost Allowance (CCA) acceleration) recognizing that the PILS amount may be updated in the draft rate order stage • Accept that the impact of Bill C-97 for 2018 and 2019 will be captured in the Capital Related Revenue Requirement Variance Account (CRRRVA)	PILs are impacted by OEB staff's rate base and capital expenditure arguments
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	Cost of capital is impacted by OEB staff's rate base and capital expenditure arguments
Cost Allocation • Accept proposed methodology used for cost allocation • The cost allocation model will need to be re-run at the draft rate order stage of the proceeding	N/A
Rate Design • Accept proposed fixed / variable split • Accept proposed loss factor update • Accept all proposed changes to retailer, specific and other service charges. However, there are a few OEB-approved sector wide changes to these charges that occurred since the filing of the application, which should be updated at the draft rate order stage of the proceeding. • Accept revised proposal with respect to customer-owned vault access policy	N/A
Deferral and Variance Accounts • Accept proposed Group 1 account disposition on an interim basis • Accept proposed no disposition of 2018 balance in LRAMVA • Accept proposed Group 2 account disposition with the exception of 2019 forecast balances and the Impact of USGAAP deferral account • The 2019 balances in the Group 2 accounts should be disposed as part of the 2021 Custom IR update application • Accept disposition of credit balances related to accounts receivable, deferred gain on disposals, and excess expansion deposits (which are not recorded in approved deferral accounts for the 2015-2019 period)	Reduce the refund to customers related to the credit balance in the deferral and variance accounts by $47.4 million in 2020. However, in 2021, there will be a

• Accept ESM calculation for 2015-2018 (no ESM amounts to be shared for the period) but a new methodology is required for 2020-2024 • Accept proposed new accounts for 2020-2024: Excess Expansion Deposits and Pension and Other Post-Employment Benefits (OPEB) forecast accrual versus actual cash payment differential carrying charges accounts • Establish new account for Carillion Insolvency Payments Receivable • No account closures as part of current proceeding (due to proposal on 2019 forecast balance disposition as part of 2021 Custom IR update application)	forecast $64.6 million credit balance related to 2019 Group 2 account balances to be refunded to ratepayers.
Total Impact on CPCI Funded 2020-2024 Revenue Requirement ($)	**$174.5-$194.5 million reduction (revenue requirement)**

The total impact of OEB staff's argument is to reduce the proposed incremental CPCI funded revenue requirement ($681.3 million) for the 2020-2024 Custom IR term by approximately 25% to 28%. This results in a CPCI funded revenue requirement increase relative to the 2015-2019 Custom IR term of approximately 14% (which compares to Toronto Hydro's proposed increase of 19%).

OEB staff observes that Toronto Hydro 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, Toronto Hydro provided the necessary information, in a timely manner, which has allowed this proceeding to continue virtually uninterrupted, notwithstanding the need for major updates.

The submission that follows is organized in accordance with the approved issues list for this proceeding.[11]

[11] Decision on Issues List, Partial Decision on Confidentiality and Procedural Order No. 3 / February 5, 2019 / Schedule A.

3. General (Issue 1.0)

3.1 Has Toronto Hydro responded appropriately to all relevant OEB directions from previous proceedings (Issue 1.1)?

There were four OEB directions set out in the OEB's Decision and Order with respect to Toronto Hydro's 2015-2019 Custom IR application. The four directions are discussed below.

Customer Engagement

Toronto Hydro was ordered to rectify certain deficiencies with respect to its customer engagement as part of the current application. Specifically, the OEB stated that Toronto Hydro did not provide its customers sufficient information on the context of the proposed application such as its existing benchmarking ranking and its relative levels of productivity and efficiency. In addition, the OEB stated that Toronto Hydro did not develop its plan in conjunction with its customer engagement activities. Instead, it sought to confirm the plan it had already prepared rather than engaging its customers to ascertain their preferred options.[12]

OEB staff submits that Toronto Hydro has made improvements in its customer engagement in the current proceeding relative to the last proceeding. Toronto Hydro has responded appropriately to this direction.

With respect to the finding on the provision of benchmarking information, Toronto Hydro, in both the online feedback portal and telephone surveys, provided information to customers with respect to both its capital and OM&A costs relative to other Ontario distributors.[13]

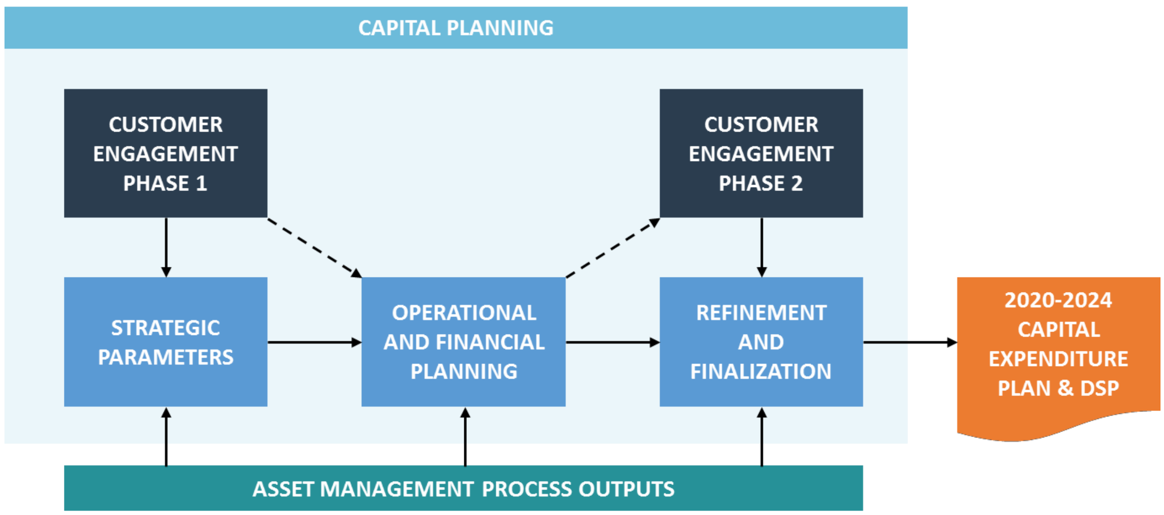
Toronto Hydro conducted the customer engagement in two phases. The feedback received in Phase 1 was used to inform the strategic parameters for the business plan and the development of the penultimate plan that was brought back for further customer feedback in Phase 2. The feedback in Phase 2 was used to make further refinements to the business plan.[14] Overall, the two phase customer engagement process allowed customer feedback to inform both the planning and refinement of its business plan.

[12] EB-2014-0116 / Decision and Order / December 29, 2015 / pp. 7-8.
[13] Exhibit 1B / Tab 3 / Schedule 1 / Appendix A / p. 22.
[14] Exhibit 1B / Tab 3 / Schedule 1 / pp. 4-5.

Toronto Hydro stated that it engaged its customers in a robust and enhanced process and that its investment plan is aligned with customer priorities.[15] Toronto Hydro's customers, in all rate classes, generally supported Toronto Hydro's plan.[16]

OEB staff notes that the feedback received from customers through the customer engagement process was used by Toronto Hydro as a component of the overall capital planning process as shown in the figure below.[17]

Figure 1
Capital Planning Process



Toronto Hydro used the information received from customers in Phase 1 to inform the strategic parameters for the capital plan. The strategic parameters also considered many other inputs (e.g. historical and forecast system performance, evolving business conditions, workforce needs and challenges, etc.).[18] Furthermore, the overall capital planning process (shown in Figure 1) also relied on inputs from its asset management processes and other operational planning activities.[19]

In reviewing the capital budget changes that occurred between the initial plan, the penultimate plan and the final plan, it is clear that some of the changes were driven directly by customer feedback. Other changes were driven by Toronto Hydro's own

[15] Argument-in-Chief / pp. 4, 23.
[16] Exhibit 1B / Tab 3 / Schedule 1 / Appendix A / p. 3.
[17] Exhibit 2B / Section E2 / p. 2.
[18] Exhibit 2B / Section E2 / pp. 3-4.
[19] Exhibit 2B / Section E2 / p. 1.

asset management processes and the refinement of program-level budgets based on Toronto Hydro's view of the needs of its system.[20] The feedback of customers was considered by Toronto Hydro as one input, of many, in the overall planning process.

The level of detail provided in a rebasing application with respect to the need and rationale for proposed spending is far beyond the information that could possibly be provided and processed in a customer engagement process (no matter how comprehensive that engagement process is). Similar to how Toronto Hydro considers customer feedback in its planning process, OEB staff submits that the OEB should consider the feedback from Toronto Hydro's customers as one input in its decision-making process along with all the other evidence that has been filed in this proceeding.

Loss Adjustment Factors

Toronto Hydro was ordered to update its loss factors at its next cost of service or Custom IR rate application.[21]

Toronto Hydro proposed updated loss factors for all rate classes in Exhibit 8 / Tab 1 / Schedule 1 / pp. 9-10. OEB staff is of the view that Toronto Hydro has responded appropriately to this directive.

OEB staff's submission on the Loss Adjustment Factors is set out in section 9.2.

Monitoring and Reporting

Toronto Hydro was ordered to develop better performance metrics as part of its ongoing customer engagement efforts with the objective of achieving greater conformity with the general intent of the Renewed Regulatory Framework (RRF).[22]

OEB staff submits that Toronto Hydro provided more comprehensive performance metrics in its proposed custom scorecard. In total, there are 15 custom metrics in addition to the OEB's standard scorecard metrics.[23] OEB staff submits that Toronto Hydro responded appropriately to this directive, subject to the detailed submissions

[20] 2B-Staff-73(a).
[21] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 46.
[22] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 47.
[23] Exhibit 1B / Tab 2 / Schedule 1 / pp. 6-7.

OEB staff makes on some of the individual metrics and the custom scorecard provided in section 4.2.

Disposition of Retail Settlement Variance Accounts (RSVA)

Toronto Hydro was ordered to request disposition of all RSVA balances in its next rate application following the conclusion of the OEB audit.[24]

OEB staff notes that Toronto Hydro sought disposition of the noted accounts as part of its 2017 Custom IR update proceeding.[25] OEB staff submits that Toronto Hydro has, in an earlier proceeding, responded to this directive.

3.2 Is the proposed effective date of January 1, 2020 appropriate (Issue 1.2)?

Toronto Hydro proposed an effective date of January 1, 2020.[26] OEB staff submits that the proposed effective date is appropriate. Toronto Hydro filed its application more than 16 months in advance of its proposed effective date. Such an early filing necessitated comprehensive updates to the application. OEB staff is of the view that such an early filing is not necessary. However, OEB staff notes that the updates required to the application have not placed the timing of the implementation date of the final rate order at significant risk.

OEB staff also notes that there have been no other delays in the processing of the application that were caused by the applicant.

3.3 Are the rate and bill impacts resulting from Toronto Hydro's application appropriate (Issue 1.3)?

The monthly distribution (sub-total A) bill impacts for typical residential and GS < 50 kW customers are shown in Table 1.

The monthly distribution (sub-total A) bill impacts for all other rate classes are shown in Undertaking J7.4. OEB staff notes that there were further updates made over the course of the proceeding (as summarized in Undertaking J1.2) that are not reflected in

[24] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 53.
[25] EB-2016-0254.
[26] Exhibit 1A / Tab 2 / Schedule 1 / p. 2.

the bill impacts in Undertaking J7.4. These updates operate to reduce the bill impacts shown in Undertaking J7.4.

OEB staff has made a number of arguments that have the impact of reducing rates and bill impacts.

OEB staff also notes that no rate mitigation is required if the OEB were to accept Toronto Hydro's proposals. However, OEB staff's arguments operate to reduce the bill impacts and also better smooth the bill impacts over the Custom IR term.

4. Custom Incentive Rate-setting (Issue 2.0)

4.1 Are all elements of Toronto Hydro's Custom Incentive Rate-setting proposal for the determination of rates appropriate (Issue 2.1)?

Toronto Hydro proposed the continuation of its Custom IR framework as was approved in its 2015-2019 Custom IR proceeding.[27]

The proposed Custom IR framework seeks to establish 2020 distribution rates on a cost of service basis. The rates for 2021-2024 are to be adjusted annually by its proposed CPCI as follows:

$$CPCI = I – X + C – g; \text{ or}$$
$$CPCI = I – X + Cn – (Scap * I) - g$$

Where:

- "I" is the OEB's inflation factor (determined annually)
- "X" is the sum of:
  - The OEB's productivity factor
  - Toronto Hydro's custom stretch factor
- "C" is the difference between:
  - "Cn" a reflection of Toronto Hydro's capital investment needs
  - "Scap (or the scaling factor) * I" is an offsetting reduction required to ensure that the capital factor provides funding only in excess of what is already provided for capital through the inflation factor

[27] Exhibit 1B / Tab 4 / p. 1.

- "g" is the growth factor determined by growth in distribution revenue due to changes in load and customer count over the Custom IR term.[28]

Below is a summary of Toronto Hydro's proposed 2020 revenue requirement and the proposed inputs for the calculation of the CPCI value, which is used to determine rates for the 2021-2024 period.[29]

Table 3
2020 Revenue Requirement and Inputs for the 2021-2024 CPCI Calculation

($M)	2020	2021	2022	2023	2024	Total
ROE	$162.0	$170.4	$179.1	$189.3	$198.9	$899.7
Interest	$100.2	$105.4	$110.8	$117.1	$123.0	$556.4
Depreciation	$265.5	$281.5	$292.3	$314.0	$327.1	$1,480.5
PILs	$12.7	$22.0	$13.4	$27.8	$40.4	$116.3
Capital-related revenue requirement (CRR)	**$540.5**	**$579.3**	**$595.6**	**$648.1**	**$689.4**	**$3,052.8**
OM&A	$278	$280.5	$283.0	$285.6	$288.1	$1,415.2
Revenue Offsets	-$47.1	-$47.5	-$47.9	-$48.4	-$48.8	-$239.6
Non capital-related revenue requirement	**$230.9**	**$233.0**	**$235.1**	**$237.2**	**$239.4**	**$1,175.6**
Base Revenue Requirement (RR)	**$771.4**	**$812.3**	**$830.7**	**$885.3**	**$928.7**	**$4,228.4**

The table below provides the calculation of the proposed CPCI values and the proposed CPCI funded revenue requirement (i.e. the revenue requirement funded in rates) based on the inputs listed above.[30]

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[28] Exhibit 1B / Tab 4 / p. 12.

[29] Undertaking J8.5. This includes the updates discussed in the original filing of Undertaking J1.2 (July 2, 2019). However, there was a minor update to Undertaking J1.2 (July 31, 2019) for the application costs ($0.2 million) that are not reflected in these amounts. OEB staff notes that the impact of this additional change on the revenue requirement is not material. The amounts provided (and related calculations) in this section of the submission ignore the $0.2 million update provided on July 31, 2019 as it will not have a material impact (and the noted update was filed later than all of the information upon which these calculations are based).

[30] Undertaking J1.8. The 2020-2024 CPCI funded revenue requirement is lower than the total base revenue requirement. The base revenue requirement shown in Tables 3 and 4 forms part of the calculation of the CPCI values. While the CPCI funded revenue requirement is a result of the CPCI formula, which includes certain offsetting adjustments (stretch and growth factors).

Table 4
Calculation of Proposed CPCI Values and CPCI Funded Revenue Requirement ($M)

Revenue Requirement	2020	2021	2022	2023	2024	Total
CRR	$ 540.46	$ 579.30	$ 595.57	$ 648.13	$ 689.36	$ 3,052.82
Non-CRR	$ 230.93	$ 233.01	$ 235.10	$ 237.22	$ 239.35	$ 1,175.61
Base RR	$ 771.39	$ 812.31	$ 830.67	$ 885.35	$ 928.71	$ 4,228.43
I		0.0120	0.0120	0.0120	0.0120	
X		0.0030	0.0030	0.0030	0.0030	
Cn		0.0504	0.0200	0.0633	0.0466	
Scap		0.7132	0.7170	0.7321	0.7423	
G		0.0020	0.0020	0.0020	0.0020	
CPCI		0.0488	0.0184	0.0615	0.0447	
CPCI Funded RR		$ 809.03	$ 823.94	$ 874.60	$ 913.66	**$ 4,192.61**

The CPCI values as shown in Table 4 are as follows[31]:

- 2021 – 4.88%
- 2022 – 1.84%
- 2023 – 6.15%
- 2024 – 4.47%[32]

Over the 2020-2024 Custom IR term, Toronto Hydro is seeking to recover in rates, through its proposed CPCI formula, a base revenue requirement of $4,192.6 million.[33] This compares to an approved CPCI funded revenue requirement for the 2015-2019 period of $3,511.3 million.[34] This represents an increase of $681.3 million (or 19.4%) when comparing the 2015-2019 Custom IR term to the 2020-2024 Custom IR term.

Toronto Hydro's proposed Custom IR framework also includes an ESM, certain capital-related variance accounts, Z-factor and off-ramp provisions.[35]

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[31] Undertaking J1.8.
[32] Undertaking J1.8.
[33] Undertaking J1.8. Note that the 2020 revenue requirement is included in the total CPCI funded revenue requirement of $4,192.6 million for the 2020-2024 Custom IR term (as this is the total amount that Toronto Hydro requested be funded in rates over the term). However, the 2020 revenue requirement is not impacted by the CPCI formula. The CPCI formula only impacts the years 2021 to 2024.
[34] 1B-Staff-23 / p. 2.
[35] Exhibit 1B / Tab 4 / pp. 13-14.

OEB staff is of the view that the business case for the continuing use of a Custom IR framework that includes a C-factor is not as persuasive as it may have been in Toronto Hydro's last proceeding. OEB staff supports the Custom IR framework for the 2020-2024 period on the basis of the following terms:

- The stretch factor should be increased to 0.45% (from the proposed 0.3%), which is supported by the evidence filed by Pacific Economics Group Research LLC (PEG). A stretch factor of 0.45% also reflects an average of Toronto Hydro's proposed stretch factor of 0.3%[36], PEG's recommended stretch factor of 0.45%[37] and the OEB's most recent generic stretch factor assigned to Toronto Hydro of 0.6%.[38]

- An incremental stretch factor on capital of 0.64% (termed Cx by OEB staff) discussed in the PEG evidence[39] should be included in the CPCI formula

- The growth factor should be increased to 0.25% (from the proposed 0.2%)

- The earnings sharing mechanism should be redesigned

- The Derecognition variance account should be closed

In addition, OEB staff submits that reductions directly to Toronto Hydro's proposed capital budget (section 5.2) and OM&A budget (section 7.1) are necessary.

Finally, Toronto Hydro should be encouraged to move away from a cost of service model for capital expenditures (as reflected by its proposed C-factor) in future applications unless Toronto Hydro is confident that it can address the concerns outlined in this submission. Instead, a single test year rebasing with a standard price-cap IRM (with the availability of ACM and ICM treatment for discrete capital projects) or an alternative Custom IR framework that does not include a C-factor cost recovery mechanism would be appropriate.

OEB staff's submission on the proposed Custom IR framework is divided into three main categories: (a) concerns with the proposed CPCI and Toronto Hydro's reduced

[36] Exhibit 1B / Tab 4 / Schedule 2 / PSE Report.
[37] Updated Exhibit M1 / PEG Report.
[38] Report to the Ontario Energy Board – Empirical Research in Support of Incentive Rate-setting (2018 Update) / August 2019.
[39] PEG terms the incremental stretch factor on capital as the S-factor.

need for a CPCI (specifically, the capital factor); (b) the required adjustments to the proposed CPCI formula; and (c) comments on the other (non-CPCI) aspects of the proposed Custom IR framework.

<u>OEB Staff's Concerns with the Proposed Custom IR Framework and Toronto Hydro's Reduced Need for a CPCI</u>

Toronto Hydro is seeking approval to continue the use of the current Custom IR framework, which includes a mechanism within the CPCI, the capital factor (or C-factor), which inflates rates each year to recover the incremental capital-related revenue requirement associated with growth in its rate base. Toronto Hydro was the first utility to receive approval of a C-factor as part of a Custom IR framework and this application reflects the OEB's first opportunity to review the actual results of a Custom IR term that included a C-factor.[40]

Toronto Hydro stated that its proposed Custom IR framework is consistent with the framework previously approved by the OEB in Toronto Hydro's 2015-2019 Custom IR proceeding to address the same needs and circumstances that Toronto Hydro currently faces.[41] OEB staff assessed this application with a view to ensure that the proposal continues to result in just and reasonable rates.

Toronto Hydro cited the OEB's decision in the 2015-2019 Custom IR proceeding as follows[42], "[t]he OEB does not decide whether the option chosen by the applicant is the most appropriate. The OEB decides rather whether the proposal contains features that can be relied on to achieve the RRFE objectives. The Custom IR is described in the RRFE as a suitable choice for distributors with large or highly variable capital requirements."[43]

In the same decision, the OEB stated, "[a]t the heart of the RRFE policy objectives are customer-focused outcomes and continuous performance improvements by distributors."[44]

[40] Oral Hearing Transcripts / Vol. 6 / pp. 82-83.
[41] Argument-in-Chief / p. 8.
[42] Argument-in-Chief / p. 10.
[43] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 4.
[44] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 4.

With respect to the OEB's findings in Toronto Hydro's 2015-2019 Custom IR proceeding, cited above, OEB staff submits that the OEB will have to consider whether the proposal contains the features that can still be relied on to achieve the RRF objectives (including customer-focused outcomes and continuous improvement) based on the evidence before it in this proceeding.

In the context that this is the second time that Toronto Hydro is seeking approval of a Custom IR framework, OEB staff submits that it is appropriate to review the actual results of Toronto Hydro's 2015-2019 Custom IR term, evaluate how Toronto Hydro's Custom IR framework fits within the OEB's policy framework for Custom IR[45], and consider whether Custom IR treatment with a C-Factor continues to be required.

The Results of Toronto Hydro's 2015-2019 Custom IR Framework

Toronto Hydro's approved Custom IR framework for the 2015-2019 period allowed for a significant amount of capital expenditures (and associated increases in rate base and rates). Some key figures include:

- Toronto Hydro made capital investments of $2,379.4 million on an actual basis over the 2015-2019 Custom IR term.[46]
- Toronto Hydro brought into service assets valued at $2,504.9 million on an actual basis over the 2015-2019 Custom IR term.[47]
- Toronto Hydro's rate base increased by 37.7% between 2015 and 2019 on an actual basis.[48]
- The approved CPCI for the 2015-2019 Custom IR term resulted in average distribution bill impacts over the 2015-2019 period of approximately 7% per year for residential customers. Similar bill impacts were experienced by customers in

[45] The policy framework referred to is largely set out in the Report of the Board on the Renewed Regulatory Framework for Electricity Distributors / October 18, 2012; the OEB Handbook for Utility Rate Applications / October 13, 2016; and other relevant decisions that dealt with Custom IR requests in the past.
[46] Exhibit U / Tab 2 / Schedule 2 / p. 3. Note that the 2019 capital expenditures are still considered forecast.
[47] Exhibit U / Tab 2 / Schedule 1 / Appendix A. Note that the 2019 in-service additions are still considered forecast.
[48] Exhibit U / Tab 2 / Schedule 1 / p. 1. Note that the 2019 in-service additions are still considered forecast.

nearly all rate classes.[49] This reflects an approximate increase of 38% between 2015 and 2019.

Toronto Hydro has experienced continual declines in its cost performance over the 2015-2019 term based on its expert's (Power System Engineering Inc. (PSE)) evidence and the evidence of OEB staff's expert (PEG). This trend is expected to continue into the 2020-2024 Custom IR term.[50]

OEB staff submits that the 2015-2019 Custom IR framework allowed Toronto Hydro to invest significantly in its system over the relevant period, resulting in increases to rates (and associated bill impacts) and declining cost performance.

Toronto Hydro's proposals in the current proceeding represent an increase to the significant capital spending that occurred during the previous Custom IR term. The proposed 2020-2024 capital expenditures ($2,830.7 million) and in-service additions ($2,776.4 million) are higher than the actuals experienced during the 2015-2019 term.[51] Toronto Hydro's capital expenditures have been on a lengthy and steady trajectory upwards since at least 2010.

OEB staff is concerned that the ongoing approval of a Custom IR framework for Toronto Hydro and specifically a C-factor, designed in the manner that it has proposed, leads to minimal incentives to control capital spending.

The Proposed CPCI is not sufficiently distinct from a Multi-Year Cost of Service

Toronto Hydro's proposed CPCI with respect to its treatment of capital for the 2020-2024 period, is at its foundation, a cost of service based form of ratemaking.[52] For each year of the Custom IR term, Toronto Hydro re-forecasts its rate base (using its proposed capital expenditures and related in-service amounts) to determine the annual capital-related revenue requirement. The year-over-year change in the capital-related revenue

[49] Undertaking J7.4. Sub-total A-related bill impacts (excluding rate riders).
[50] Exhibit M3 / PSE Reply Report / May 31, 2019 / p. 4; and Updated Exhibit M1 / PEG Report / pp. 53-54.
[51] Undertaking J1.7.
[52] In contrast, OEB staff submits that the treatment of OM&A within the proposed CPCI is not cost of service based. The submissions set out here are with respect to the treatment of capital within the proposed CPCI.

requirement is what is captured by the C-factor (more specifically, the Cn term) in the CPCI formula.[53]

Toronto Hydro, through its CPCI formula, recovers nearly every dollar related to its forecast capital needs (reflected by the increase in the year-over-year capital-related revenue requirement) over the Custom IR term (net of only a small stretch factor). In the current proceeding, the proposed stretch factor of 0.3%[54] results in a $17.2 million reduction to the total forecast capital need (as reflected by the capital-related revenue requirement).[55] This amounts to an approximate 0.56% reduction to the total 2020-2024 proposed capital-related revenue requirement of $3,052.8 million.[56]

OEB staff submits that while Toronto Hydro's proposed CPCI is presented as a mechanistic formula (as set out previously) to adjust rates, it is underpinned by cost of service-based calculations for capital funding during the 2020-2024 term.

The *Handbook for Utility Rate Applications* (Rate Handbook),[57] states that "Custom IR is not a multi-year cost of service."[58] OEB staff recognizes that Toronto Hydro's CPCI includes a stretch factor but it is not sufficient on a going forward basis to meaningfully differentiate Toronto Hydro's proposed Custom IR framework from a multi-year cost of service.

OEB staff notes that the significant capital spending that occurred during the 2015-2019 period is evidence that the Custom IR framework as proposed by Toronto Hydro in this proceeding (which was the same as was approved in the 2015 Custom IR proceeding[59]) is effective at providing Toronto Hydro with all the funding necessary to support its stated capital needs. To a certain extent, this is the original intent of making a Custom IR option available to utilities with large capital needs. However, the incentive for Toronto Hydro to become more efficient when assessing the manner in which it deploys its capital has become so small in OEB staff's view that it now verges on a departure from a core principle of incentive ratemaking, which is that rates are decoupled, for a period of time, from utility costs. As discussed in the context of the OEB's review of

[53] Exhibit 1B / Tab 4 / Schedule 1.
[54] Exhibit 1B / Tab 4 / Schedule 1 / p. 7.
[55] Oral Hearing Transcripts / Vol. 6 / p. 78.
[56] Oral Hearing Transcripts / Vol. 6 / p. 78.
[57] Toronto Hydro's 2015-2019 Custom IR decision was issued in December 2015. The OEB Rate Handbook for Utility Rate Applications was issued in October 2016.
[58] OEB Rate Handbook for Utility Rate Applications / October 13, 2016 / p. 25.
[59] EB-2014-0116.

Hydro One Network Inc.'s (Hydro One) 2015-2019 rates proceeding[60], "the decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation."[61] OEB staff submits that Toronto Hydro's proposed CPCI does not sufficiently decouple its rates from its capital costs for the subject period and may get worse in future rate-setting terms in the event that Toronto Hydro continues proposing a C-factor.

Proposed 2020-2024 Custom IR Framework does not reflect Continuous Improvement

As was established in the *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors*, operational effectiveness, which is defined as continuous improvement in productivity and cost performance, is a central outcome expected of distributors.[62] With respect to a Custom IR application, the Rate Handbook states that, explicit financial incentives for continuous improvement and cost control targets must be included in the application. Furthermore, productivity incentives are to be incorporated through a custom index or an explicit revenue reduction over the plan and not built into the cost forecast.[63]

OEB staff submits that Toronto Hydro's proposed 2020-2024 Custom IR framework does not sufficiently reflect the requirement for continuous improvement. In Toronto Hydro's 2015-2019 Custom IR framework, the OEB approved a stretch factor of 0.6%.[64] In the current proceeding, Toronto Hydro is seeking approval of a stretch factor of 0.3%.[65] Toronto Hydro is seeking a lower stretch factor in the current proceeding relative to the last plan. This means that it will actually need to find less productivity savings over the 2020-2024 term than it did in the 2015-2019 plan. OEB staff submits that a 0.3% stretch factor is inadequate as it does not incorporate a sufficient productivity incentive to reflect the level of continuous improvement that should be expected of a utility that is seeking approval of a Custom IR framework (with C-factor treatment for capital) for the second time.

OEB staff also submits that Toronto Hydro has not directly quantified any of the capital productivity savings that it forecasts it may achieve over the 2020-2024 Custom IR term

[60] EB-2013-0416 / EB-2014-0247
[61] EB-2013-0416 / EB-2014-0247 / Decision / March 12, 2015 / p. 14.
[62] Report of the Board on the Renewed Regulatory Framework for Electricity Distributors / October 18, 2012 / p. 2.
[63] OEB Rate Handbook for Utility Rate Applications / October 13, 2016 / p. 25.
[64] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 15.
[65] Exhibit 1B / Tab 4 / Schedule 1 / p. 7.

and used the related savings to offset its requests for capital funding.[66] As such, with respect to capital, the only productivity requirement built into the plan is the proposed 0.3% stretch factor (as it applies to capital) as there are no explicit revenue reductions to reflect these productivity improvements.

To explain how productivity is included in Toronto Hydro's proposed budgets, Toronto Hydro relies on the productivity achievements made over historical periods. The productivity achievements over the past period are reflected in its actual costs and therefore are reflected in the forecast (as the forecast costs are based, as a starting point, on historical actuals).[67] OEB staff submits that the inclusion of productivity achievements from previous periods is expected of utilities and it does not alone satisfy the requirement for continuous improvement.

Toronto Hydro also stated that it has a long-standing history of continuous improvement and productivity that has evolved since amalgamation in the early 2000's leading to achieved productivity embedded in the OM&A and capital program expenditures. Both capital and OM&A productivity improvements (including capital investments resulting in sustainable OM&A savings) have contributed to Toronto Hydro's strong results on a total cost benchmarking basis.[68]

Toronto Hydro appears not to take into account the impact of its ongoing cost increases on its ability to sustain cost efficiencies and productivity improvements. Toronto Hydro's performance has been declining over time based on the evidence of both PSE and PEG.[69] Table 5 shows Toronto Hydro's actual costs to 2018, and forecasted costs for 2019-2024, relative to what would be estimated by the total cost benchmarking models of PSE and PEG.

[66] Oral Hearing Transcripts / Vol. 6 / p. 78-79.
[67] Oral Hearing Transcripts / Vol. 6 / p. 79-80.
[68] Undertaking J3.2.
[69] Exhibit M3 / PSE Reply Report / May 31, 2019 / p. 4; and Updated Exhibit M1 / PEG Report / pp. 53-54.

Table 5
PSE Total Cost Results vs. PEG Total Cost Results[70]

Year	PSE Reply Report Results[71]	PEG Updated Report Results[72]
2015	-18.4%	-4.6%
2016	-15.7%	0.8%
2017	-13.8%	3.7%
2018	-10.5%	7.5%
2019	-9.3%	8.7%
2020	-7.2%	11.4%
2021	-5.5%	13.4%
2022	-3.3%	15.9%
2023	-1.6%	17.8%
2024	-0.1%	19.5%

PSE and PEG's analyses differ in terms of the level of cost efficiency. PSE estimates that Toronto Hydro's actual costs are better than forecasted benchmark costs based on Toronto Hydro's operating conditions through to 2024. In contrast, PEG estimates that Toronto Hydro's costs start to exceed the benchmark costs in 2016. However, what both analyses agree on is the trend. Toronto Hydro's cost efficiency deteriorates in a continual manner.

Toronto Hydro also stated that the outcome of its history of continuous improvement and productivity is reflected in Toronto Hydro's strong performance in the UMS unit cost benchmarking study. Toronto Hydro's UMS unit cost benchmarking is more positive in terms of Toronto Hydro's cost performance. This reflects a number of normalizations applied by UMS that have a material impact on the results. OEB staff notes that using all of the normalizations that UMS believes are appropriate[73], Toronto Hydro falls largely within quartile two (with two exceptions) for the 11 categories of capital and

[70] Table 5 shows the percentage difference of Toronto Hydro's actual / forecasted budget costs relative to what the PSE / PEG models would predict based on Toronto Hydro's operating conditions. A negative result means that the actual / forecasted costs are below the benchmark (i.e. better cost performance), while a positive result means that actual/forecasted costs are above the benchmark (i.e. poorer cost performance).
[71] Exhibit M3 / PSE Reply Report / May 31, 2019 / p. 4.
[72] Updated Exhibit M1 / PEG Report / pp. 53-54.
[73] Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 16-17. The normalization applied include adjustments for: (a) "raw comparisons" – accounting for conversions from imperial to metric units and US to CAD dollars; (b) "Pre-analysis adjustors" – adjusting for regional cost variances and for the different methods used by utilities in applying indirect and overhead costs to unit costs; and (c) "fully-scaled normalization" – incorporating commonly incurred difficulty factors.

maintenance costs reviewed.[74] This means that it is performing better than the median.[75]

OEB staff submits that some of the normalizations completed required a great deal of judgment on behalf of UMS. Specifically, the “fully-scaled normalization”, which incorporated difficulty factors in the determination of an appropriate comparison of unit costs across utilities, result in rather large changes to the overall cost comparison. For example, Toronto Hydro is assigned a score of six for population density. A comparator utility is assigned a score of four for population density. All else being equal, this will result in the comparator utility’s unit costs, for any relevant asset and maintenance categories, being increased by 9%.[76] Similar adjustments, with large impacts, are made for underground utility congestion, external factors, weather and climate and vegetation.[77] The impact of these adjustments are not supported by empirical analysis.[78] Instead, it is supported by UMS’ judgement and experience in this area.[79] OEB staff submits that the “fully-scaled normalizations” result in unreasonably large adjustments to the unit costs of the comparator utilities.

OEB staff submits that if only normalization adjustments for items that involve significantly less judgement (i.e. conversion to metric system, US to Canadian dollar conversion, and accounting practices regarding indirect and overhead costs) were made, the results are less positive. In fact, Toronto Hydro falls below the median for ten out of the 11 categories of capital and maintenance activities.[80]

OEB staff found the UMS study helpful. However, this type of unit cost study would be more helpful in the future where trends could be analyzed. Regardless of where one lands on the normalizations applied by UMS, the study shows that there is plenty of room for improvement in terms of unit cost performance.

Overall, OEB staff submits that Toronto Hydro’s proposed Custom IR framework does not sufficiently address the requirements for continuous improvement as established by

[74] Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 7; and 1B-Staff-4. The two exceptions are pole top transformers (quartile 3) and vegetation management (quartile 1).
[75] Oral Hearing Transcripts / Vol. 8 / pp. 104-105.
[76] Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / p. 33; and Oral Hearing Transcripts / Vol. 8 / p. 122.
[77] Exhibit 1B / Tab 2 / Schedule 1 / Appendix B / pp. 32-33. The applicability of the different adjustment factors to the asset and maintenance categories is described in detail in Table C-6 and C-7.
[78] Oral Hearing Transcripts / Vol. 8 / p. 127.
[79] Oral Hearing Transcripts / Vol. 8 / pp. 124-125.
[80] Oral Hearing Transcripts / Vol. 8 / pp. 112-113; and Exhibit K8.3 / SEC Panel 4 Compendium / p. 35.

the RRF. In addition, its total cost benchmarking shows that its cost performance is declining over time and there appears to be room for improvement on a unit cost basis.

The Appropriate Incentives for a Custom IR Framework

OEB staff submits that Toronto Hydro's proposed Custom IR framework does not incentivize appropriate utility decision-making.

PEG notes that the knowledge that a C-factor mechanism for capital recovery may be available (i.e. the ability to recover nearly all incremental capital costs) can incentivize a utility to exaggerate its capital needs in order to make a case for C-factor approval and therefore reduce the pressure to contain capital expenditures over the Custom IR term.[81] Acceptance of this view means that the design of Toronto Hydro's proposed Custom IR framework does not have sufficient counter incentives in place.[82]

The CPCI as proposed (with the inclusion of a C-factor) incentivizes the spending of capital over OM&A[83] as capital spending is unconstrained by a single test year budget (2020), while OM&A is constrained by the proposed test year budget. This leads to the potential for sub-optimal decisions being made (i.e. even if an OM&A expenditure could more cost-effectively address an issue during the Custom IR term, a capital decision may be favoured by the utility).

For the reasons above, OEB staff submits that adjustments are required to the framework as proposed for the 2020-2024 period.

The Need for a Capital Factor is Reduced

OEB staff submits that, in addition to the design problems discussed previously with respect to the Custom IR framework, the need for a capital factor has reduced for the proposed 2020-2024 period relative to the 2015-2019 period. OEB staff expects that the need will reduce even further by 2025.

[81] Updated Exhibit M1 / PEG Report / p. 62.
[82] With respect to its capital plan, Toronto Hydro stated in its Argument-in-Chief (page 23) that its plan is "a restrained plan that represents a minimum level of investment necessary to maintain average reliability and customer service performance and deliver targeted improvements for customers experiencing below average service." OEB staff is of the view that Toronto Hydro's capital plan does, to some extent, include capital spending that is beyond its requirements. OEB staff has made arguments for specific reductions to certain programs contained in the capital budget in section 5.2.
[83] Updated Exhibit M1 / PEG Report / p. 62.

OEB staff has undertaken analysis that compares the funding provided by Toronto Hydro's approved 2015-2019 Custom IR framework to a counterfactual whereby a single test year rebasing (2015) and a price-cap IRM to adjust rates for the 2016-2019 period was approved instead. OEB staff has also compared the funding provided by Toronto Hydro's proposed 2020-2024 Custom IR framework to a counterfactual whereby the application is viewed a single test year rebasing (2020) with price-cap IRM based adjustments to rates for the 2021-2024 period.[84] The analysis completed for each of the time periods are then compared with each other to determine whether the need for Toronto Hydro's proposed Custom IR framework has reduced period-over-period.

This analysis is shown in Exhibit K6.4 / page 55 and Toronto Hydro, while not agreeing with the interpretation of the analysis, confirmed that the numbers included in the analysis are correct.[85] Toronto Hydro did raise some concerns with the approved capital expenditure amounts used in the analysis for the 2015-2019 period. However, OEB staff submits that the capital expenditure amounts used in the analysis are, at a minimum, a reasonable proxy of the approved amounts for that period. In the Draft Rate Order from the 2015-2019 Custom IR proceeding,[86] these amounts are found under the heading of "Approved Capital Expenditure Amounts."[87]

OEB staff submits that comparing the funding provided to Toronto Hydro based on its Custom IR framework relative to a counterfactual of an IRM rate-setting model is a reasonable way to evaluate the need for Custom IR funding of a utility's stated needs. Custom IR is intended to fit a utility's specific circumstances and is most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels.[88] It is OEB staff's view that the implication of this statement is that there has to be a pressing need for Custom IR treatment (or otherwise there would not be the necessary utility specific circumstances present to require a form of funding that is incremental to the more standard option of IRM). On that basis, OEB staff submits that it is appropriate to compare the levels of funding provided under an IRM option to Custom IR to determine whether there is truly a need for Custom IR treatment.

[84] OEB staff notes that its counterfactual IRM scenarios assume that there are no approvals for any ACMs or ICMs.
[85] Oral Hearing Transcripts / Vol. 6 / pp. 105-119. Toronto Hydro confirmed the math, with the exception of OEB staff's approach of dividing percentages by percentages to show the relative change in proportional shortfalls both between funding models and the two periods reviewed.
[86] EB-2014-0116.
[87] EB-2014-0116 / Draft Rate Order Update / February 29, 2016 / p. 4.
[88] Report of the Board on the Renewed Regulatory Framework for Electricity Distributors / October 18, 2012 / p. 18-19.

OEB staff provides a brief summary of some of the key results of its analysis in the following discussion.[89]

For the 2015-2019 period, Toronto Hydro was, funded through rates, $2,497.9 million for its capital-related revenue requirement based on its approved Custom IR framework. If it had been approved a price-cap IRM instead, it would have been funded, through rates, $2,204.7 million for its capital-related revenue requirement. This reflects an IRM funding shortfall of $293.2 million (or 11.74%).[90]

For the 2020-2024 period, if Toronto Hydro's application is approved as filed, Toronto Hydro would be provided funding through rates of $3,035.7 million for its capital-related revenue requirement based on its proposed Custom IR framework. If instead, the OEB were to treat Toronto Hydro's application as a price-cap IRM, Toronto Hydro would be provided funding through rates of $2,751.6 million for its capital-related revenue requirement. This reflects an IRM funding shortfall of $284.1 million (or 9.36%).[91] OEB staff also notes that the IRM funding shortfall of capital-related revenue requirement would be even smaller if the OEB were to approve any ACMs or ICMs for discrete major capital projects under the counterfactual price-cap IRM option.

OEB staff notes that the proportional shortfall (i.e. the IRM funding shortfall in percentage terms) decreases by 2.38% period-over-period.[92] This means that the proportional shortfall, in terms of capital-related revenue requirement funding, between Custom IR and IRM is 20.27% lower in the 2020-2024 period relative to the 2015-2019 period.[93]

On this basis, OEB staff submits that the capital-related revenue requirement funding shortfall as between Custom IR and price-cap IRM has decreased between the 2015-

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[89] OEB staff refers directly to the spreadsheet that it developed to provide a summary of the results of the analysis undertaken (Exhibit K6.4 / p. 55). As noted previously, Toronto Hydro confirmed that the numbers in the spreadsheet are correct. OEB staff notes that all of the references to where the specific amounts used for the analysis can be found on the record are provided in Exhibit K6.4.
[90] Exhibit K6.4 / p. 55.
[91] Exhibit K6.4 / p. 55.
[92] Calculated as 11.74% minus 9.36%.
[93] OEB staff submits that dividing the change in proportional shortfall (-2.38%) by the 2015-2019 funding shortfall percentage (11.74%) to determine the relative change in the proportional shortfall period-over-period is entirely appropriate. While OEB staff agrees with Toronto Hydro that dividing percentages by other percentages does not result in meaningful results in some contexts, it has clear meaning here. Essentially, the calculation shows that the capital-related revenue requirement funding shortfall in the 2020-2024 period is approximately 20% lower than that same shortfall (calculated in exactly the same manner) was in the 2015-2019 period.

2019 period and the 2020-2024 period. Relatedly, this means that the need for the Custom IR framework (which includes an incremental capital recovery mechanism through the C-factor) is also reduced.

OEB staff submits that it is also important to look beyond the shortfall in capital-related revenue requirement funding between the funding models. OEB staff notes that depreciation expense is the return of originally invested capital that is available for re-investment in the replacement assets when the original assets reach end-of-life.[94] Toronto Hydro agreed that depreciation expense is available to fund capital expenditures.[95] As such, an important consideration, in OEB staff's view, is the availability of funding for capital expenditures through depreciation expense.

For the 2015-2019 period, Toronto Hydro's depreciation funding of capital expenditures was 52.95% based on its approved Custom IR framework. If it had been approved a price-cap IRM instead, Toronto Hydro's depreciation funding of capital expenditures would have been 47.09%. This reflects an IRM shortfall with respect to the funding of capital expenditures through depreciation expense of 5.86%[96] (or a proportional shortfall of 11.07%[97]).[98]

For the 2020-2024 period, Toronto Hydro's depreciation funding of capital expenditures is 52.00% based on its proposed Custom IR framework. If instead the OEB were to treat Toronto Hydro's application as a price-cap IRM, Toronto Hydro's depreciation funding of capital expenditures would be 47.75%. This reflects an IRM shortfall with respect to the funding of capital expenditures through depreciation expense of 4.25%[99] (or a proportional shortfall of 8.18%[100]).[101] OEB staff also notes that the IRM shortfall, in terms of depreciation funding of capital expenditures, would be even smaller if the OEB were to approve any ACMs or ICMs for discrete major capital projects under the counterfactual price-cap IRM option.

[94] Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report / January 22, 2016 / p. 9.
[95] Oral Hearing Transcripts / Vol. 6 / pp. 113-114.
[96] Calculated as 52.95% minus 47.09%.
[97] Calculated as 5.86% divided by 52.95%.
[98] Exhibit K6.4 / p. 55.
[99] Calculated as 52% minus 47.75%.
[100] Calculated as 4.25% divided by 52%.
[101] Exhibit K6.4 / p. 55.

OEB staff notes that the proportional shortfall (i.e. the IRM shortfall in percentage terms) decreases by 2.89%[102] period-over-period. This means that the proportional shortfall between Custom IR and IRM, in terms of depreciation expense funding of capital expenditures, is 26.11%[103] lower in the 2020-2024 period relative to the 2015-2019 period.[104] OEB staff submits that this is a significant reduction in the shortfall. OEB staff expects that the shortfall will likely get much smaller in future rate setting terms given the size of Toronto Hydro's current rate base and the significant amount of assets that it plans to place into service in future years. More generally, this means that the need for the Custom IR framework (which includes an incremental capital recovery mechanism through the C-factor) is already reduced and may be reduced even further in future rate-setting periods.

OEB staff also compared the depreciation funding of Toronto Hydro's in-service additions to that which is received by the other utilities in the province using historical information available through the Electricity Reporting and Record Keeping Requirement data (RRR data). OEB staff performed the comparison on the basis of in-service additions (as opposed to capital expenditures) as this is the information that was readily available. OEB staff notes that over the proposed 2020-2024 Custom IR term, Toronto Hydro's capital expenditures and in-service additions are very closely aligned in aggregate. While, there are year-to-year differences, over the term, Toronto Hydro's proposed capital expenditures are 1.9% higher than its proposed in-service additions.[105] For these reasons, OEB staff submits that reviewing depreciation funding of in-service additions is closely aligned with a review of depreciation funding of capital additions over time.

OEB staff's comparison of Toronto Hydro's proposed 2020-2024 depreciation funding of in-service additions to the actual historical depreciation funding of in-service additions across the industry is set out in Exhibit K6.4 / page 85. The RRR data used in the analysis is provided at Exhibit K6.4 / page 86.[106]

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[102] Calculated as 11.07% minus 8.18%.
[103] Calculated as 2.89% divided by 11.07%.
[104] Exhibit K6.4 / p. 55.
[105] Undertaking J1.7.
[106] The RRR data used is reflected in the OEB's annual yearbook of electricity distributors with the exception of the information with respect to capital contributions and the 2018 data (as the 2018 annual yearbook is not yet released). As noted in section 1.7 of the Electricity Reporting and Record Keeping Requirements Report / November 29, 2018 / p. 5, the RRR information used is not confidential and available to the public.

OEB staff notes that Toronto Hydro's proposed depreciation expense funds approximately 53.02% of its in-service additions over the 2020-2024 period if its Custom IR framework is approved as filed. Instead, if Toronto Hydro's application was applied price-cap IRM treatment, its depreciation expense would fund 48.68% of its proposed in-service additions. OEB staff notes that the Ontario-wide average ratio of depreciation expense funding of in-service additions is 49.21% based on 2015-2018 historical actuals.[107]

OEB staff submits that Toronto Hydro would receive a level of depreciation expense funding for its in-service additions (which is closely related to capital expenditures), if it were applied price-cap IRM treatment, that is nearly the same as all other utilities in the province receive on average (48.68% compared to 49.21%). OEB staff notes that if Toronto Hydro were to receive approval for ACM or ICM treatment for discrete major capital projects under the price-cap IRM option, its depreciation funding of in-service additions would be even higher than the 48.68% cited above. OEB staff submits that this is another reason that the need for the proposed Custom IR framework has reduced.

OEB staff notes that the RRR data to which Toronto Hydro's 2020-2024 depreciation expense is compared is not precisely a like-for-like comparison. First, the depreciation expense in the RRR data reflects a gross figure as it shows depreciation on gross capital assets (which does not remove the depreciation associated with capital contributions).[108] Toronto Hydro essentially confirmed this, at the oral hearing, in terms of explaining the difference between its own historical RRR data (included in the dataset) and the historical depreciation expense shown in its application.[109] OEB staff notes that the proposed depreciation expense for the 2020-2024 period for ratemaking purposes is a net depreciation figure (i.e. only the depreciation of assets that are in rate base and not recovered through a capital contribution). OEB staff submits that the result of this is that the depreciation expense reflected in the RRR data is higher than the depreciation expense that is used for ratemaking purposes.

Second, OEB staff is comparing Toronto Hydro's depreciation funding of in-service additions to a utility-wide average ratio of actual depreciation expense relative to actual

[107] Exhibit K6.4 / p. 85.
[108] More specifically, the RRR data shows gross depreciation for assets that came into service after 2015 (concurrent with the adoption of IFRS). For assets that came into service prior to 2015, the RRR data reflects net depreciation. Therefore, the RRR data reflects a blend of both net depreciation (assets in-service prior to 2015) and gross depreciation (assets in-service after 2015).
[109] Oral Hearing Transcripts / Vol. 2 / pp. 19-20.

in-service additions. OEB staff submits that the actual depreciation as a percentage of actual in-service additions shown in the RRR data is higher than the amount that utilities are typically funded through rates. For example, a utility that is on price-cap IRM will receive its test year depreciation expense in rates (escalated for I-X) but as its rate base grows over the period, and assuming that it is investing capital at a rate faster than I-X, its actual depreciation expense (shown in the RRR data) will be higher than the amount that is funded in rates. Therefore, OEB staff submits that the depreciation expense in the RRR data is also likely overstated relative to the depreciation expense used for ratemaking purposes for this reason.

Overall, OEB staff is of the view that the ratio of deprecation expense funding of in-service additions included in the RRR data, while not exactly a like-for-like comparison to Toronto Hydro's proposed depreciation expense funding of in-service additions, provides a reasonable proxy for comparison. If any adjustment were to be made to the RRR data to make it more comparable to Toronto Hydro's proposed amounts, the ratio of depreciation expense funding of in-service additions shown in the RRR data would be adjusted downwards (i.e. the 49.21% historical average ratio would be some amount lower).

OEB staff also notes that Toronto Hydro's 2025 rate base will be significantly higher than its 2020 rate base due to magnitude of its proposed in-service additions for the 2020-2024 period ($2,776.4 million).[110] Toronto Hydro's proposed 2024 rate base is $5,636.3 million, which compares to its proposed 2020 rate base of $4,592.6 million.[111] OEB staff submits that this increase in its rate base will provide even more capital funding at the start of the next rate-setting term (2025) relative to the current term.

Overall, OEB staff is of the view that Toronto Hydro's need for a Custom IR framework that includes a C-Factor is reduced for the 2020-2024 term and Toronto Hydro should be required to substantiate the continuing need for this treatment in future applications, including addressing the type of analysis that OEB staff outlined above.

The Resolution to OEB staff's concerns with the Proposed Custom IR Framework

OEB staff has discussed its concerns with Toronto Hydro's proposed Custom IR framework. These concerns include: (a) the treatment of capital in the CPCI formula for the 2020-2024 period does not sufficiently decouple rates from utility costs; (b)

[110] Undertaking J1.7.
[111] Undertaking J1.7.

continuous improvement is not adequately included in the plan; (c) the design of the proposed Custom IR framework can result in in inappropriate incentives; and (d) the need for Custom IR treatment has reduced for Toronto Hydro relative to when the OEB initially approved this treatment as part of the 2015-2019 proceeding.

OEB staff submits that its concerns with the proposed Custom IR framework can be adequately resolved in the current proceeding through direct adjustments to the CPCI formula[112], other aspects of the Custom IR framework[113], and reductions to the proposed capital and OM&A budgets.[114] OEB staff submits that increasing the stretch factor and including an incremental stretch factor on capital will help to address the concerns with respect to continuous improvement. OEB staff notes that its proposal would result in a total stretch factor applied to the base revenue requirement, through the CPCI formula, of 0.91% on average during the Custom IR term.[115] OEB staff submits that this would incorporate a sufficient productivity incentive to reflect the level of continuous improvement that should be expected of a utility that is seeking approval of a Custom IR framework (with C-factor treatment of capital) for the second time. This will also, to a certain extent, decouple Toronto Hydro's rates from its costs.

OEB staff's acceptance of Toronto Hydro's proposed Custom IR framework, with the noted adjustments, is not an endorsement of this treatment in future proceedings. The adjustments discussed above reflect a reasonable solution for the 2020-2024 term. However, the treatment proposed by Toronto Hydro may be untenable over a longer term. Simply increasing stretch factors on capital (as proposed by OEB staff for this proceeding) does not address the underlying problems with Toronto Hydro's proposed Custom IR framework or the fact that its need for such treatment has reduced. OEB staff submits that the core policy objectives of the RRF, as cited in the OEB's decision in Toronto Hydro's 2015-2019 Customer IR application[116], of customer-focused outcomes and continuous improvement cannot be reconciled within the Custom IR framework as proposed by Toronto Hydro in perpetuity without evidence of improved performance and need.

[112] Increasing the base stretch factor (0.45%) and the inclusion of an incremental stretch factor on capital (0.64%).
[113] Redesign of the earnings sharing mechanism and closure of the derecognition variance account.
[114] These reductions are discussed in detail in sections 5.2 and 7.1, respectively.
[115] This is calculated as the 0.45% base stretch plus 0.64% incremental stretch on capital * Scap (which averages approximately 72.6% over the 2021-2024 period).
[116] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 4.

At the end of the 2024 term, Toronto Hydro will have been allowed the recovery of capital-related revenue requirement for a 10-year period. Previous to the last Custom IR term, Toronto Hydro was approved significant capital recovery through an ICM.[117] This level of funding could very well allow Toronto Hydro to sufficiently re-invest in its system and grow its rate base to a level that permits it to fund capital expenditures, beginning in 2025, in the absence of capital funding that is incremental to the standard price-cap IRM formula.

For these reasons, OEB staff submits that the OEB should signal to Toronto Hydro that it should not expect continued approval of a Custom IR framework that includes a C-factor in future applications in the absence of addressing the concerns outlined in this submission. If Toronto Hydro cannot address the framework design issues and provide evidence verifying improved cost performance and need, Toronto Hydro should be encouraged to file a price-cap IRM (with ACM / ICM eligibility for only discrete major capital projects) [118] or an alternative Custom IR framework that does not include a C-factor cost recovery mechanism.[119]

OEB staff acknowledges that Toronto Hydro may have not yet decided what type of application it will file for its subsequent rate term. OEB staff also recognizes that a decision in this proceeding cannot bind the deliberations of a panel in a future Toronto Hydro rates case. A future application will be considered on its own merits by the OEB panel assigned to that proceeding. A finding of this nature operates as guidance to Toronto Hydro when deciding on and developing its subsequent rate-setting framework. As discussed previously, Toronto Hydro has other options available to it including leveraging the OEB's ACM approach, for discrete major capital projects, that provides some degree of funding certainty for the entire five-year term in a single test year rebasing application.

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[117] EB-2012-0064.
[118] OEB staff notes that, as discussed later in this section of the submission, the incremental stretch factor on capital proposed by OEB staff does not result in the same level of cost constraints as a price-cap IRM with ACM/ICM eligibility.
[119] OEB staff notes that the OEB made similar findings in both Ontario Power Generation Inc.'s (OPG) 2011-2012 Payment Amounts proceeding and its 2014-2015 Payment Amounts proceeding. In both those cases, the OEB signaled to OPG that it should transition its rate-setting methodology from a cost of service approach to an incentive rate-setting approach.

The Required Adjustments to the CPCI Formula and related Inputs

OEB staff submits that the following adjustments are required to the CPCI formula and related inputs in the context of its concerns with the overall proposed Custom IR framework:

- The stretch factor should be increased to 0.45% (from the proposed 0.3%) as set out in the PEG evidence. A stretch factor of 0.45% also reflects an average of Toronto Hydro's proposed stretch factor of 0.3%[120], PEG's recommended stretch factor of 0.45%[121] and the OEB's most recent generic stretch factor assigned to Toronto Hydro of 0.6%.[122]

- An incremental stretch factor on capital of 0.64% (Cx) based on the PEG evidence should be included in the CPCI formula.

- The growth factor should be increased to 0.25% (from the proposed 0.2%).

OEB staff submits that based on these proposals the CPCI formula should be revised as follows.

$$CPCI = I – X + C – g; \text{ or}$$
$$CPCI = I – X + Cn – (Scap * (I + Cx)) – g$$

Where:

- "I" is the OEB's inflation factor (determined annually)
- "X" is the sum of:
    - The OEB's productivity factor
    - Toronto Hydro's custom stretch factor
- "C" is the difference between:
    - "Cn" a reflection of Toronto Hydro's capital investment needs
    - "Scap * (I + Cx)" is an offsetting reduction required to ensure that the C-factor provides funding only in excess of what is already provided for

[120] Exhibit 1B / Tab 4 / Schedule 2 / PSE Report.
[121] Updated Exhibit M1 / PEG Report.
[122] Report to the Ontario Energy Board – Empirical Research in Support of Incentive Rate-setting (2018 Update) / August 2019.

capital through the inflation factor and includes a necessary incremental stretch factor to capital in order to appropriately incentivize productivity

- “g” is the growth factor determined by grown in distribution revenue due to changes in load and customer count over the Custom IR term.

The result of the proposed changes on the CPCI are set out in the following table.

Table 6
Calculation of OEB Staff Submission CPCI Values and CPCI Funded Revenue Requirement ($M)

Revenue Requirement	2020	2021	2022	2023	2024	Total
CRR	$ 540.46	$ 579.30	$ 595.57	$ 648.13	$ 689.36	$ 3,052.82
Non-CRR	$ 230.93	$ 233.01	$ 235.10	$ 237.22	$ 239.35	$ 1,175.61
Base RR	$ 771.39	$ 812.31	$ 830.67	$ 885.35	$ 928.71	$ 4,228.43
I		0.0120	0.0120	0.0120	0.0120	
X		0.0045	0.0045	0.0045	0.0045	
Cn		0.0504	0.0200	0.0633	0.0466	
Scap		0.7132	0.7170	0.7321	0.7423	
Cx		0.0064	0.0064	0.0064	0.0064	
G		0.0025	0.0025	0.0025	0.0025	
CPCI		0.0422	0.0118	0.0548	0.0379	
CPCI Funded RR		$ 803.96	$ 813.48	$ 858.06	$ 890.59	**$ 4,137.49**

The revised CPCI values as shown in Table 6 are as follows:

- 2021 – 4.22%
- 2022 – 1.18%
- 2023 – 5.48%
- 2024 – 3.79%

OEB staff’s proposed changes to the CPCI formula results in the reductions to the CPCI funded revenue requirement (or in other words, that amount of revenues recoverable through rates) as set out in the following table.[123]

[123] Toronto Hydro proposed CPCI funded revenue requirement is from Undertaking J1.8. The OEB staff proposed CPCI Funded revenue requirement is a calculated amount that results from the revised CPCI formula. The CPCI funded revenue requirement would be reduced if the OEB accepts OEB staff’s submissions with respect to rate base, capital expenditure and OM&A reductions.

Table 7
CPCI Funded Revenue Requirement Comparison ($M)

	2020	2021	2022	2023	2024	Total
Toronto Hydro Proposed CPCI Funded RR	$ 771.39	$ 809.03	$ 823.94	$ 874.60	$ 913.66	$ 4,192.62
OEB Staff Proposed CPCI Funded RR	$ 771.39	$ 803.96	$ 813.48	$ 858.06	$ 890.59	$ 4,137.49
Variance	$ -	$ (5.07)	$ (10.46)	$ (16.54)	$ (23.07)	$ (55.13)

Each of the proposed changes to the CPCI formula are discussed in more detail in the sub-sections that follow.

Inflation Factor

Toronto Hydro proposed to use the OEB's existing two-factor IPI for electricity distributors, which is updated and published annually. The IPI is a weighted average of labour (30%) and non-labour (i.e. capital and materials) annual price changes based on data published by Statistics Canada. Toronto Hydro proposes to update the inflation factor used in its CPCI calculation at the draft order stage to reflect the most recent OEB-approved inflation value and in each of its annual Custom IR update applications.[124] OEB staff has no concerns with Toronto Hydro's proposal.

OEB staff asked an interrogatory seeking Toronto Hydro's views should the OEB change the IPI methodology as a result of any generic review for electricity distribution rate-setting methodologies. Toronto Hydro indicated that the impact of a change in the inflation calculation methodology would have to be assessed at that time.[125] OEB staff considers Toronto Hydro's response to be reasonable. OEB staff submits that, if a generic change to the methodology were to occur, Toronto Hydro should bring forward its proposal with respect to the inflation factor to be used in its CPCI calculation in the Custom IR update proceeding immediately following any generic methodology change.

Base Productivity

Toronto Hydro proposed to use the base productivity of 0%, as accepted by the OEB for 4th Generation electricity distribution IRM.[126] OEB staff accepts Toronto Hydro's proposal.

[124] Exhibit 1B / Tab 4 / Schedule 1 / p. 5.
[125] 1B-Staff-18; and Oral Hearing Transcripts / Vol. 7 / p. 140-141.
[126] Exhibit 1B / Tab 4 / Schedule 1 / p. 6; and EB-2013-0379 / Supplemental Report / November 2013.

OEB staff asked an interrogatory seeking Toronto Hydro's views should the OEB change the base productivity as a result of any generic review for electricity distribution rate-setting methodologies. Toronto Hydro indicated that the impact of a change in the inflation would have to be assessed at that time.[127] OEB staff consider Toronto Hydro's response to be reasonable. OEB staff submits that, if a generic change to the base productivity factor were to occur, Toronto Hydro should bring forward its proposal with respect to the inflation factor to be used in its CPCI calculation in the Custom IR update proceeding immediately following any generic methodology change.

Base Stretch Factor

In Ontario, with approximately 60 electricity distributors in existence, and now two decades of experience in Performance Based Regulation (PBR) / IRM, cost benchmarking analyses provide a quantitative basis for setting the stretch factor.

The evidence of PSE and PEG on total cost benchmarking for Toronto Hydro and a sample of comparator utilities provide the quantitative basis for the stretch factor in the proposed CPCI formula. Toronto Hydro and its consultant, PSE, have proposed a stretch factor of 0.3%.[128] OEB staff's consultant PEG proposed a stretch factor of 0.45%.[129] These both represent a change from 0.6% as approved for Toronto Hydro's current Custom IR plan for 2015-2019.[130]

OEB staff submits that a stretch factor of 0.45% should be applied in Toronto Hydro's CPCI formula. OEB staff notes that this is the stretch factor recommended in the PEG evidence.[131] Recognizing some of the issues and concerns that emerged and were contested over the course of this proceeding with respect to the total cost benchmarking undertaken by the experts (PSE and PEG), a 0.45% stretch factor also reflects an average of Toronto Hydro's proposed stretch factor 0.3%[132], PEG's recommended stretch factor 0.45%[133] and the OEB's most recent generic stretch factor assigned to Toronto Hydro of 0.6%.[134]

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[127] 1B-Staff-19; and Oral Hearing Transcripts / Vol. 7 / p. 141-142.
[128] Exhibit 1B / Tab 4 / Schedule 1 /, pp. 6-7, Exhibit 1B / Tab 4 / Schedule 1 / pp. 1, 12-13, 49
[129] Exhibit M1 / pp. 9, 61
[130] EB-2014-0116, Decision and Order, December 29, 2015, p. 19
[131] Updated Exhibit M1 / PEG Report.
[132] Exhibit 1B / Tab 4 / Schedule 2 / PSE Report.
[133] Updated Exhibit M1 / PEG Report.
[134] Report to the Ontario Energy Board – Empirical Research in Support of Incentive Rate-setting (2018 Update) / August 2019.

OEB staff provides its submissions on the issues that emerged from testing of the expert evidence in the following sub-sections.

Total Cost Benchmarking

As a starting point, OEB staff think that it is useful to express the cost function modelling that PSE and PEG are doing in a generic way. Costs are expressed as a function of various factors, termed business condition variables, which would influence the level (quantum) of costs of a utility. As different utilities face different business conditions, they would have different levels of costs, all else being equal. The intention of the total cost benchmarking analyses conducted by PSE and PEG is to try to identify the cost drivers (or proxies of them) and estimate the parameters based on a sample of utilities, so that more of an “apples-to-apples” comparison can be done.[135] At the end, whether a utility is a good or poor cost performer is assessed against what the estimated cost model would predict based on the utility’s business condition variable values. Toronto Hydro’s proposed stretch factor, as recommended by PSE, is based on the cost model estimated from actual historical data of Toronto Hydro and a sample of U.S. utilities, and six other Ontario distributors, as well as on the forecasted cost performance based on Toronto Hydro’s proposed operating and capital costs during the plan term. PEG’s analysis is largely a variation on PSE’s approach, where PEG has attempted to improve on certain issues and shortcomings that it identified as part of the review of PSE’s evidence.

These cost drivers, and their influences on the level of costs, also depend on the nature of the service area, with the experts, PSE and PEG, accepting a rural-suburban-urban split.[136] Some costs are invariant to this split (e.g., billing and customer call centre). Some of the drivers of costs may be specific to a specific area, while others may be common to two or all three zones (e.g. tree cover, undergrounding and conduited undergrounding, climactic conditions), but their impacts may be different.
However, one aspect that PSE and PEG agree on, and that OEB staff also concur with, is that costs for serving both rural and urban areas are higher than for serving suburban areas (the “sweet spot”).[137]

[135] Oral Hearing Transcripts / Vol. 9 / pp. 67-68.
[136] Technical Conference Transcripts / Vol. 4 / pp. 168-172; and Oral Hearing Transcripts / Vol. 9 / pp. 82-87.
[137] This is the “bath tub” curve that PSE and PEG acknowledged in testimony. Oral Hearing Transcripts / Vol. 9 / pp. 84-87.

What we have are the total costs for each firm for serving the mix of urban, suburban, and rural areas that the firm serves in its licensed service territory. (PSE confirmed that costs are not broken out by service sub-territory.[138]) The modelling approach is then to try to explain the costs based on drivers and also adjusting for the mixture of urban, suburban and rural areas and on how “urban” and “rural” cost drivers would, overall, increase costs relative to a hypothetical “suburban” utility. It is this cost function that PSE and PEG are trying to estimate, and to improve the modelling of, over time.

However, getting good data that is consistent across utilities and over time is not always easy. PSE and PEG have articulated in their evidence and in testimony the challenges faced in doing this. Obviously, dealing with Canadian-U.S. exchange rates is one, but even here, the optimal solution is not obvious. Should an exchange rate be used or an alternative measure like Purchase Power Parity (PPP)? This is an obvious example, but does exemplify the issues faced in these econometric analyses.

PSE and PEG have many similarities in their cost benchmarking approaches. The differences are often with respect to details on how to deal with the availability, quality and consistency of data, which are well documented on the record.[139] These differences do have an impact, as PSE and PEG do come up with different numbers and recommendations. However, it is not always clear which differences in approaches are material.

Some of these differences, such as asset price levelization, may not be as material on the results as PSE contends. Capital asset prices have become an issue subsequent to the development of 4th Generation IRM. In Canada, the Electrical Utility Construction Price Index (EUCPI) was the best series available for Ontario distributors, but Statistics Canada ceased its publication in 2015. PSE prefers the Handy-Whitman Index, a U.S. series, and uses the northeastern region for Ontario. PEG uses an alternative series

[138] Oral Hearing Transcripts / pp. 73.
[139] Exhibit M1 / pp. 15-26 provides PEG’s review of PSE’s initial evidence. Various interrogatories, specifically, 1B-Staff-27 to 1B-Staff-45; Exhibit L1 / M1-TH-001 to M1-TH-031; Exhibit L3 / L3-Staff-1 to L3-Staff-8; and L3-EP-73 to L3-EP-75. The PSE “Reply report to PEG's report (IRM design for Toronto Hydro-Electric system)” filed as Exhibit M1 on May 31, 2019 is largely an argument report critiquing PEG’s evidence and IR responses, with limited updated evidence as discussed in Oral Hearing Transcripts / Vol. 9 / pp. 100-102. PSE reiterated these criticisms in its Examination-in-Chief (Oral Hearing Transcripts / Vol. 9 / pp. 51-65). PEG addressed these concerns during its Examination-in-Chief, including concerns on the filing of the unsolicited Exhibit M3 (Oral Hearing Transcripts / Vol. 10 / pp. 3-16). Both of the PSE and PEG witnesses further discussed similarities and differences during their testimonies (PSE: Oral Hearing Transcripts / Vol. 9 / pp. 65-211; and PEG: Oral Hearing Transcripts / Vol. 10, pp. 16-157).

from Statistics Canada for utility capital prices, but it is not exclusive to electricity distribution utilities. The long-run trend of available series seem relatively consistent, but there are differences[140] in the short-run that can have an impact on the model results depending on the price series and base year used.

In its Reply Report, and during the Oral Hearing, PSE focused on an error in PEG's analysis, which used 2008 as the base year for levelizing Toronto Hydro's asset prices, but 2012 for levelizing asset prices for the U.S. utilities. In testimony, PEG explaining that, while there is some volatility between the series, the trend appears stable between the two series beginning in 2008, and so the choice is not as meaningful as PSE contends.[141]

More importantly, while some assumptions and analytical approaches may be more accepted than others, there is generally no one single accepted approach. Economists and econometricians may differ in their approaches.

There are the two proposals for the stretch factor: 0.3% from PSE and 0.45% from PEG. Both experts have done their analyses using similar approaches. Differences in assumptions, data and data adjustments and corrections are technical in nature. It is also not clear how significant the differences are to the outputs of the analyses. Further, at best, these are model – simplistic representations – of unknown real world phenomena; there is no perfect solution.

OEB staff believes that PEG's estimate of 0.45%, and its analysis, are preferable, for reasons discussed in the following subsections. OEB staff believes that PEG has attempted to best address the issues that it has identified with PSE's approach in its own evidence. However, there are limitations to both PSE's and PEG's benchmarking filed in this proceeding. OEB staff notes that a 0.45% stretch factor also reflects an average of Toronto Hydro's proposed stretch factor of 0.3%[142], PEG's recommended

[140] These are generally methodological details on the construction of the price index series of interest mainly to economists and econometricians. The choice of the base year for the weights of the components used to construct the price series is one such technical detail. PSE discusses this in its May 31, 2019 Reply Report, and this was further discussed during the oral hearing, with PEG (Oral Hearing Transcripts / Vol. 9 / pp. 59-60.
[141] Oral Hearing Transcripts / Vol. 10 / pp. 125-130.
[142] Exhibit 1B / Tab 4 / Schedule 2 / PSE Report.

stretch factor of 0.45%[143] and the OEB's current generic stretch factor assigned to Toronto Hydro of 0.6%.[144]

Congested Urban Variable

One important new variable introduced in PSE's study in this case is for "congested urban" (%CU). This replaces the much simpler binary variable which PSE used in its total cost study in Toronto Hydro's previous Custom IR application. PSE noted that the search for an improved variable was prompted by the OEB's concerns expressed in the previous application.[145] It was also noted that a different variable, the percentage of service territory that is "artificial surface" (%Art) was used in PSE's total cost benchmarking study filed in the Hydro One Networks distribution application.[146] PEG also included the congested urban variable in its study.

The %CU variable constructed by PSE is new. It employs GIS mapping data, Google Earth data and images, and a fair bit of examination and some judgement to determine "congested urban" areas with concentrations of buildings at least seven stories high and within cities with populations of at least 200,000.

OEB staff agrees with PEG that this concept has some merits. It is certainly an advance, at least conceptually, on the binary variable used in previous studies of PSE and PEG filed in Toronto Hydro's previous Custom IR proceeding.[147]

However, this is the first use of this variable, and it should not be considered as perfect. A consideration of the map of Toronto in PSE's report is informative.[148] Toronto has a %CU value of 1.88%. Examination of the map shows that the Yorkdale / Hwy. 401 / Spadina Expressway Area is not congested urban, although it is likely that Toronto Hydro would face similar issues of conduit-encased underground cable and assets, and difficulties in coordinating work with road, public transportation and other infrastructure in an area that is heavily developed and used but with buildings less than seven stories high. Similarly, the area around the Hwy. 401 / 404 junction and Fairview Mall is not

[143] Updated Exhibit M1 / PEG Report.
[144] Report to the Ontario Energy Board – Empirical Research in Support of Incentive Rate-setting (2018 Update) / August 2019.
[145] Oral Hearing Transcripts/ Vol. 9/ pp. 76-77.
[146] Exhibit K9.2 / p. 18; and Oral Hearing Transcripts Vol. 9 / p. 79,
[147] EB-2014-0116.
[148] Exhibit 1B /Tab 4 / Schedule 2 / p. 51.

congested urban. There are likely other areas in the City of Toronto where similar arguments could be raised.[149]

OEB staff also notes that the %CU variable is based on a snapshot in time, and is fixed for the time period. This may be adequate for some cities and some utilities, but different cities experience different growth rates and patterns over time. Toronto, in particular, is one of the fastest growing cities in North America, and particularly in terms of multi-story commercial/residential (i.e., densification). The %CU value is based on recent data. If %CU had been calculated over time, then it would have varied. However, this would have required a lot more effort to construct, and it is not clear that the GIS and street view data would be available for all years and all cities.

The importance of this critique, with respect to the %CU being based on a snapshot in time, is that, if %CU is an important (proxy for) a cost driver, a utility's costs in a particular year (e.g. 2005) would be driven by the %CU value in the same year, not by the value in a benchmark year such as 2016. This would be more important for faster growing cities like Toronto.

The %CU variable is a promising proxy, but it does appear to have limitations. OEB staff submit that further refinement is warranted before it becomes fully accepted. PEG also expressed similar points about the promise of this variable, but also noted its current flaws.[150] With the exception of the analyses by PSE and PEG in response to undertakings during the oral hearing (to exclude the %CU variable), its benefits have not been tested relative to alternatives.

PEG and OEB staff have also expressed concerns that PSE has included %CU linearly, in a quadratic form ($\%CU^2$), and in an interaction (cross-product) term (%UGU = %CU x %UG) and in $\%UGU^2$. PEG expressed its concerns that many such second- and higher-order terms are not intuitive, use up degrees of freedom, and may result in erroneous model estimates.[151] PEG did not include all of these higher-order terms in its model. OEB staff submits that PEG's model is preferred due to a more judicious inclusion of higher order terms, to avoid introduction of unintuitive and likely erroneous model estimates.

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[149] Oral Hearing Transcripts / Vol. 9 / pp. 72-75. A discussion on how PSE's engineering definition of "congested urban" relating to a concentration of buildings of seven or more stories in an area may not capture all urban areas where increased costs are faced. See also Technical Conference Transcripts / Vol. 4 / pp. 168-178 for a similar discussion of urban areas in Madison, Wisconsin.
[150] Oral Hearing Transcripts / Vol. 10 / pp. 45-46.
[151] Oral Hearing Transcripts / Vol. 10 / pp. 8, 43-44.

Sample

PSE has used a sample of U.S. investor-owned utilities (IOUs), along with six other larger Ontario distributors,[152] and Toronto Hydro as the data set for estimating the total cost benchmarking model.[153] Data for the U.S. IOUs is as reported on FERC Form 1,[154] with addition data from other sources.[155] In PSE's sample, there are 90 utilities in total – 83 U.S. IOUs and the seven Ontario distributors.

The use of U.S. utilities is consistent with Toronto Hydro's previous Custom IR plan. Also, PSE used a U.S. only data set for calculating total factor productivity and total cost benchmarking for Hydro One distribution in another recent Custom IR plan.[156]

The six Ontario distributors added were larger ones serving cities with populations of at least 200,000 and where the congested urban variable (%CU), discussed further below, was non-zero. PSE included a binary variable in its model to account for differences (other than exchange rate / PPP).

PEG omitted the six other Ontario distributors, to ensure consistency of the data set with the U.S. IOUs.[157]

OEB staff accept the use of U.S. utilities, and acknowledges that FERC Form 1 is a good source for comprehensive and, to the extent possible, consistent data. The use of U.S. IOUs as comparators for Ontario distributors is appropriate.

As a comparator for Toronto Hydro, one U.S. distributor, Commonwealth Edison (ComEd) attracted some attention.[158] ComEd serves the City of Chicago as well as a significant area of Illinois west to the Iowa border and north to the Wisconsin border. In many respects, ComEd might be the closest comparator to Toronto Hydro. The Toronto and Chicago metropolitan areas are, respectively, the third and fourth largest metropolitan areas in North America, with Toronto passing Chicago in recent years.

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152 Hydro Ottawa, Horizon Utilities (now part of Alectra Utilities), Enersource Hydro Mississauga (now part of Alectra Utilities), EnWin Utilities, London Hydro and Kitchener-Wilmot Hydro.
153 Exhibit 1B /Tab 4 /Schedule 2 / pp. 14-15, p.26 / Table 5.
154 Federal Energy Regulatory Commission. FERC Form 1 is a mandatory reporting requirement for investor-owned electricity utilities in the U.S.
155 e.g., Platts, a third-party commercial vendor for GIS and mapping data, Google Earth, etc.
156 EB-2017-0049.
157 Oral Hearing Transcripts / Vol. 10 / pp. 18-21.
158 Technical Conference Transcripts / Vol. 4 / pp. 179-181; and Oral Hearing Transcripts / Vol. 9 / pp. 150-152.

Both cities have similar populations and many socioeconomic characteristics in common,[159] as well as being situated each on a Great Lake. There are some climatological differences, but also many similarities.

What distinguishes ComEd from Toronto Hydro is that ComEd also serves extensive suburban and rural areas outside of Chicago; this actually shows up in that PSE's Congested Urban value for ComEd is 0.05%, with a congested urban sq. km. of 12.73, while that of Toronto Hydro is 1.88% for a congested urban sq. km. of 12.03.[160] Based on PSE's definition of congested urban, ComEd and Toronto Hydro probably face very similar situations and cost pressures, but the impact of using %CU will be different. To this end, PEG's preference for using service territory area and "congested urban" area as separate variables may be the better approach.[161] OEB staff concurs with PEG's comments, and note that PSE's approach is equivalent to including the two components separately, but with an unintuitive condition that "congested urban" service area and total service area have coefficients that are equal but of opposite signs.

OEB staff also submits that inclusion of data for other Canadian utilities would augment these econometric analyses. OEB staff notes that a source for Canadian utility data analogous to FERC Form 1 does not appear to be available. However, OEB staff note that for other, more qualitative, benchmarking studies conducted and filed in support of DSPs, data for other Canadian utilities is frequently used. OEB staff submits that greater efforts should be made to obtain data for other Canadian utilities; these utilities are generally regulated through public processes.[162]

OEB staff believes that Ontario distributors can, and should, be included in the dataset. However, OEB staff accepts PEG's reasons for excluding the six Ontario distributors in its analyses, with respect to ensuring data consistency.[163] While Hydro One Networks and Toronto Hydro have been seen as outliers, different than most other Ontario

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[159] Both are major financial, industrial, educational, medical and transportation centres, and have heavily built up urban cores surrounded by large suburban areas.
[160] Exhibit 1B / Tab 4 / Schedule 2 /p. 50.
[161] Technical Conference Transcripts / Vol. 4 / pp. 178-190; Oral Hearing Transcripts / Vol. 9 / pp. 80-81; and Oral Hearing Transcripts / Vol. 10 / pp. 54-55.
[162] 1B-Staff-41
[163] PEG excluded the six Ontario distributors on the basis of not having all of the historical data to construct the variables, including inclusions or exclusions of costs such as Pension & OPEBs. OEB staff considers PEG's explanations as reasonable, to avoid entering errors or bias into the model estimation.

distributors, ongoing consolidation in the sector are leaving fewer and generally larger distributors.[164]

OEB staff fails to see how Toronto Hydro is any more of an outlier relative to the other Ontario distributors than it is compared to the sample of U.S. IOUs. As discussed on the record, Toronto Hydro and Consolidated Edison (ConEd, serving areas of New York City) have the largest %CU values.[165] Nearly all other U.S. IOUs serve rural as well as urban and suburban areas, while Toronto Hydro and ConEd have no material rural areas in their service territories.

Further, while PSE restricted the added Ontario distributors to those serving cities with populations of at least 200,000 and a non-zero %CU value, these same selection criteria do not apply to the U.S. IOUs. Nearly half of the U.S. IOUs have a 0% value for the congested urban variable. While most U.S. IOUs serve areas with populations over 200,000, this is for their combined urban / suburban / rural service areas. OEB staff queried PSE on these differences through an interrogatory and during the technical conference. PSE does not accept that its approach leads to sampling bias.[166]

PSE also stated that its sample selection was due to the focus on understanding Toronto Hydro's costs. If it was doing the benchmarking for another utility such as Kitchener-Wilmot Hydro, it would include other Ontario distributors in the sample.[167]

OEB staff submits that PSE's logic is flawed. The model is assumed to apply to all utilities included in the sample equally. The predicted model, as estimated, attempts to estimate the parameters of the explanatory variables so as to "best" explain the costs for all included utilities equally. If a utility was included in the sample for Kitchener-Wilmot Hydro, it should equally be included in the sample for Toronto Hydro. On the other hand, if the analyst believed that different cost functions and cost drivers applied to two different utilities, it would be inappropriate to include them both.

PEG expressed similar concerns about how PSE's sample selection, and its overall modelling approach, seems to be tailored to the main applicant utility, noting how PSE's

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[164] Toronto Hydro is now the third largest distributor in Ontario, having been surpassed by Alectra Utilities, formed as a combination of Horizon Utilities, Enersource Hydro Mississauga, PowerStream, Hydro One Brampton Networks and, recently, Guelph Hydro.
[165] Exhibit 1B / Tab 4 / Schedule 2 / p. 50; Oral Hearing Transcripts / Vol. 9 / pp. 75-76.
[166] 1B-Staff-41; Technical Conference Transcripts / Vol. 4 / pp. 155-185; Oral Hearing Transcripts / Vol. 9 / pp. 114-116.
[167] Oral Hearing Transcripts / Vol. 9 / pp. 150-152, 177-178.

evidence in the Hydro One Networks distribution application focused on the “ruralness” while the Toronto Hydro evidence in this application emphasized the “urbanness” of Toronto Hydro and other utilities in the sample.[168] PEG did not consider this to be appropriate for theoretical and principled reasons.

OEB staff agrees that it is legitimate to include U.S. utilities in a comparator set. However, PSE’s approach, which includes large number of U.S. utilities very unlike Toronto Hydro in their operating environments, but then includes only a small number of Ontario utilities based on much more restrictive selection criteria, is inappropriate. OEB staff submits that PSE’s approach of customizing the sample, and the model, to the applicant utility, is a further reason that PEG’s evidence should be preferred.

OEB staff further submits that any future analyses should be based on a consistent methodology in accordance with statistical sampling approaches, to the extent that utility data availability and quality allows. OEB staff also submits a more balanced sample of U.S., Ontario, and possibly other Canadian, utilities should be used for future studies of this kind.

Forecasted Performance

Econometric analyses, for productivity or cost benchmarking purposes, are based on actual historical data for the sector, or for a sample of firms in the sector. The reasons for this are fairly obvious. Subject to issues of data availability, consistency and quality, these data are known. To the extent that we are trying to estimate the parameters of a theoretical based relationship, but where the exact relationship must be approximated, actual historical data provides the best basis for this.

For PBR / IRM plans, the base X (base productivity) factor is derived from an analysis of historical sector productivity. If there is a belief that there is a structural change occurring in the future plan term, then there could be an adjustment based on informed judgement, but such adjustments have not been done in Ontario PBR / IRM plans, and OEB staff is unfamiliar where these may have been done elsewhere.

Also, for the annual cohort and stretch factor update, it is recent actual historical data on which the analysis is conducted. Recent historical data is known with as much certainty

[168] Oral Hearing Transcripts / Vol. 10 / pp. 40-45, 61-63.

as is possible, and represents actual performance. All else being equal, it is the best indication of how we expect the firm to continue to perform, at least in the short run.

PSE's and PEG's cost benchmarking analyses are based on historical data. However, PSE has also included forecasts of Toronto Hydro's cost performance based on Toronto Hydro's proposed budget for each year in the plan. PEG has included similar analyses.

Toronto Hydro and PSE have emphasized Toronto Hydro's forecasted cost performance relative to what the cost benchmarking model would estimate for the plan period in support of the proposed 0.3% stretch factor.[169]

OEB staff submits that the emphasis on the forecasted performance is inappropriate. It is reasonable to consider it as being informative, but it should not be considered determinative.

There are two reasons for this. First, it is only Toronto Hydro's costs which are extended into the future period, beyond 2017. Costs for other firms in the sample are not extended, largely because the data is not readily available. So this future cost performance analysis compares Toronto Hydro's expected costs against the historical data for the whole sample up to 2017. Toronto Hydro's application includes technological and operational improvements from the past, and which may not be reflected in the historical data.

Second, this analysis is based on expected performance, assuming that the world unfolds as Toronto Hydro expects and based on its proposed DSP and budget. This is unlikely; there will be many things happen, especially over the five years of the plan. This is not a criticism of Toronto Hydro's forecasting abilities, but a reflection of both internal and exogenous factors and events that will cause deviations.

OEB staff submits that greater emphasis should be placed on that historical cost performance, and that the future expected cost performance be given less consideration – it should be informative of Toronto Hydro's plan overall, but not determinative for the purposes of setting the stretch factor.

[169] PSE provided an updated table in the Reply Report (Exhibit M3 / page 3 / Table 1), which was discussed at length during the testimony of both PSE (Oral Hearing Transcripts / Vol. 9) and PEG (Oral Hearing Transcripts / Vol. 10) during the Oral Hearing.

Stretch Factor Recommendation

In OEB staff's view, the OEB should rely on PEG's evidence as an improvement on PSE's proposals, for the reasons set out above. The OEB has developed significant expertise in this area and can also be informed by its own judgment. As noted previously, a 0.45% stretch factor also reflects an average of Toronto Hydro's proposed stretch factor of 0.3%[170], PEG's recommended stretch factor of 0.45%[171] and the OEB's most recent generic stretch factor assigned to Toronto Hydro of 0.6%.[172]

Capital Factor and Incremental Stretch Factor on Capital

OEB staff notes that Toronto Hydro's proposed CPCI formula includes a capital (or "C") factor. The C-factor, as proposed, is the difference between:

- "Cn" a reflection of Toronto Hydro's capital investment needs
- "Scap * I" is an offsetting reduction required to ensure that the capital factor provides funding only in excess of what is already provided for capital through the inflation factor.[173]

OEB staff has no concerns with the manner in which the Cn factor is calculated. OEB staff also has no concerns with respect to the offsetting adjustment made through the "Scap * I" term, which ensures that the Cn factor only provides capital funding in excess of what is already provided through the inflation factor. However, OEB staff submits that an additional offsetting adjustment should be included within the C-factor. OEB staff submits that an incremental stretch factor on capital of 0.64% (termed Cx in OEB staff's revised CPCI formula) should be applied.

In the context of the significant capital funding provided by the proposed C-factor (i.e. every dollar of capital-related revenue requirement is recovered from ratepayers), OEB staff submits that a higher stretch factor on capital than that proposed by Toronto Hydro in this proceeding is necessary. OEB staff submits that the incremental stretch factor on

[170] Exhibit 1B / Tab 4 / Schedule 2 / PSE Report.
[171] Updated Exhibit M1 / PEG Report.
[172] Report to the Ontario Energy Board – Empirical Research in Support of Incentive Rate-setting (2018 Update) / August 2019.
[173] Exhibit 1B / Tab 4 / Schedule 1 / p. 12.

capital (0.64%) will ensure that Toronto Hydro is required to find incremental capital-related productivity over the Custom IR term.[174]

The incremental stretch factor on capital also ensures, in combination with the proposed increase to the base stretch factor, that the total stretch factor applied within the CPCI formula would incorporate a sufficient productivity incentive to reflect the level of continuous improvement that should be expected of a utility that is seeking approval of a Custom IR framework (with C-factor treatment of capital) for the second time.[175]

OEB staff is of the view that an incremental stretch factor on capital with a value of 0.64% is appropriate for the reasons set out by PEG.[176] OEB staff notes that the methodology used to calculate the incremental stretch factor on capital does not rely on a total cost benchmarking approach. Therefore, OEB staff notes that the limitations, previously discussed, with respect to the derivation of a base stretch factor are not present with respect to the calculation of the incremental stretch factor on capital.[177]

In response to an interrogatory from the School Energy Coalition (SEC), PEG calculated the incremental stretch factor on capital to be equivalent to the materiality threshold for supplemental capital revenue available through ACM and ICM treatment under a price-cap IRM.[178] Essentially, an incremental stretch factor on capital of 0.64%[179] is designed as a proxy of the "markdown" provided by the materiality threshold in an ICM or an ACM.[180] PEG provided detailed evidence supporting its calculation of the incremental stretch factor on capital in its response to undertaking J10.5.[181]

[174] The total stretch factor applied to the capital-related revenue requirement would be 1.09%. Calculated as 0.45% (base stretch factor) plus 0.64% (incremental stretch factor).
[175] The total stretch factor applied to the base revenue requirement, within the CPCI formula, would be on average approximately 0.91% over the 2021-2024 period. This is calculated as 0.45% base stretch plus 0.64% incremental stretch on capital * Scap (which averages approximately 72.6% over the 2021-2024 period).
[176] Exhibit L1 / PEG Response to SEC-13; and Undertaking J10.5.
[177] More specifically, OEB staff notes that the methodological and data issues related to the total cost benchmarking have nothing to do with PEG's calculation of the incremental stretch factor on capital. For this calculation, PEG relied solely on a mathematical derivation using Toronto Hydro's proposed capital budget to develop a factor that would be similar to the capital incentive implicit in the ACM / ICM materiality threshold.
[178] Exhibit L1 / PEG Response to SEC-13 / p. 2.
[179] The original calculation for the incremental stretch factor was 0.6%. This was subsequently updated by PEG to 0.64% in Undertaking J10.5 based on the application updates made by Toronto Hydro.
[180] Undertaking J10.5 / p. 3.
[181] Undertaking J10.5 / pp. 4-11.

OEB staff notes that the OEB approved an incremental stretch factor on capital in Hydro One's 2018-2022 Custom IR application.[182] In that proceeding, the OEB applied an incremental stretch factor on capital of 0.15%.[183] PEG specifically considered an incremental stretch factor on capital of 0.15% in its analysis for Toronto Hydro. PEG stated that the ACM / ICM equivalent stretch factor on capital required for Toronto Hydro is more than three times higher than in the recent Hydro One decision.[184]

OEB staff submits that PEG has calculated a reasonable proxy of the markdown provided by the materiality threshold for an ACM/ICM and as such an incremental stretch factor on capital of 0.64% is appropriate to be applied within Toronto Hydro's CPCI formula.[185]

However, OEB staff notes that while an incremental stretch factor on capital of 0.64% operates as a proxy for the materiality threshold for an ACM/ICM within a CPCI formula, it does not provide the same level of cost constraint as a price-cap IRM with ACM / ICM eligibility for discrete capital projects. PEG's proxy calculation for the incremental stretch factor on capital assumes that all in-service additions would be eligible for ACM / ICM treatment. OEB staff submits that this is not the case under price-cap IRM as ACM / ICM treatment is intended to apply only to proposed discrete major capital projects (as opposed to program-level capital additions that occur in the normal course and are expected to be funded in the absence of supplemental capital revenue).[186]

OEB staff notes that this is not a criticism of the incremental stretch factor on capital derived by PEG. OEB staff has accepted this calculation in terms of its inclusion within the CPCI formula for the 2020-2024 Custom IR term in order to ensure that incremental levels of productivity are required during this period. However, OEB staff submits that even the inclusion of an incremental stretch factor on capital does not result in the same level of cost constraint as a price-cap IRM with ACM / ICM eligibility. This supports OEB staff's argument that the OEB should signal its expectation to Toronto Hydro that its next application should consider a move away from a C-factor form of capital cost recovery unless it addresses the framework design issues and provides evidence verifying improved cost performance and need.

[182] EB-2017-0049 / Decision and Order / March 7, 2019 / pp. 31-33.
[183] EB-2017-0049 / Decision and Order / March 7, 2019 / p. 31.
[184] Undertaking J10.5 / p. 3.
[185] OEB staff submits that on the basis of this argument the revised CPCI formula should be: I – X + Cn – (Scap * (I + Cx)) – g.
[186] Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report / January 22, 2016 / p. 4.

Growth Factor

Toronto Hydro proposed a growth (or – "g") factor of 0.2%, which forms part of its CPCI calculation. The growth factor is determined by growth in distribution revenue due to changes in forecasted load and customer counts over the Custom IR period.[187]

Toronto Hydro provided the detailed calculation supporting the 0.2% growth factor.[188] OEB staff has no concerns with the methodology used to determine the growth factor. However, OEB staff notes that the result of Toronto Hydro's own calculation of the growth factor is 0.2482%. OEB staff submits that Toronto Hydro has incorrectly rounded the growth factor down to 0.2% in its CPCI calculation.[189] This should be corrected to 0.25%.

OEB Staff Submissions on the other (non-CPCI) aspects of the Proposed Custom IR Framework

Earnings Sharing Mechanism

Toronto Hydro's proposed Custom IR framework includes an ESM. The proposed ESM is based on the same methodology that was approved as part of Toronto Hydro's 2015-2019 Custom IR application.[190] The ESM, as proposed, tracks the variance between the actual non-capital related revenue requirement (OM&A and revenue offsets) and non-capital revenue requirement recovered through rates. The account is symmetrical, non-cumulative and incorporates a 100 basis point deadband.[191]

OEB staff notes, as was agreed to by Toronto Hydro, the proposed ESM essentially operates as true-up of non-capital related revenue requirement.[192] Therefore, in a hypothetical scenario, whereby Toronto Hydro had higher OM&A expenses than were approved in rates, and the 100 basis point deadband was breached, Toronto Hydro would seek recovery of those incremental costs from ratepayers.

[187] Exhibit 1B / Tab 4 / Schedule 1 / p. 12.
[188] Undertaking J8.1. OEB staff notes that the detailed calculation seems to rely on the originally filed load forecast. However, Toronto Hydro stated that the updated load forecast does not impact the growth factor (Exhibit U / Tab 1A / Schedule 2 / p. 4).
[189] Exhibit 1B / Tab 4 / Schedule 1 / p. 13.
[190] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 49.
[191] Exhibit 1B / Tab 4 / Schedule 1 / p. 14; and 1B-Staff-25.
[192] Technical Conference Transcripts / Vol. 4 / pp. 32-33.

OEB staff submits that the proposed methodology used to determine whether there are earnings to be shared with ratepayers is not appropriate going forward. The purpose of a properly designed ESM is to allow ratepayers to share in overearnings during an IR term, not to true-up OM&A expenditures and revenue offsets.

On that basis, OEB staff submits that Toronto Hydro's ESM should be re-designed. OEB staff submits that the ESM should be asymmetrical to ensure that it operates only to share overearnings with ratepayers (and not true-up expenses in excess of amounts approved by the OEB). The account should also be non-cumulative in the manner in which it is assessed (i.e. the calculation to determine whether there are earnings to be shared with ratepayers should be done for each year of the Custom IR term in isolation). The deadband for earnings sharing should continue to be 100 basis points (with 50% of any overearnings shared with ratepayers). In addition, the methodology for determining whether there are earnings to share with ratepayers should result from a comparison of actual to deemed ROE. For the actual ROE calculation, the actual net income[193] of the regulated utility should be divided by the actual deemed equity (i.e. actual rate base * deemed equity percentage). This will ensure that it adequately refunds ratepayers overearnings that are caused by changes in both costs and revenues (including changes in load relative to forecast amounts).

The Rate Handbook states that if a utility proposes an earnings sharing mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.[194] However, as OEB staff proposes that the ESM account be asymmetrical in favour of ratepayers, OEB staff submits that the earnings sharing calculation should be performed in accordance with the methodology discussed above. In particular, entries to record amounts to the ESM account should be considered annually over the Custom IR term and amounts should only be recorded to the ESM for years in which Toronto Hydro has over earned in excess of the 100 basis point deadband. The filing of the annual ESM calculations and the request for disposition of any balance within the ESM (if there are earnings to be shared with ratepayers) should be made at the time of the next cost-based application. This will avoid a potentially complex review of the ESM calculation as part of the Custom IR

[193] OEB staff recognizes that certain adjustments to net income will need to be made each year for out of period items and deferral account-related issues. These adjustments will change each year and, therefore, OEB staff cannot provide a position on the appropriateness of any specific adjustment to net income that will occur over the 2020-2024 period at this time. These adjustments should be proposed for each year of the Custom IR term and be reviewed at the time of disposition.
[194] OEB Handbook for Utility Rate Applications / p. 28.

update applications and is more in line with the approach outlined in the OEB's Rate Handbook.

Additional details regarding OEB staff's proposed revisions to the proposed ESM are provided in section 10.3.

Capital-related Variance Accounts

Toronto Hydro proposed the continuation of three capital-related variance accounts that are directly associated with its proposed Custom IR framework (specifically, the C-factor). The three accounts are: the CRRRVA, the Externally-Driven Capital variance account and the Derecognition variance account.[195]

OEB staff supports the continuation of the CRRRVA and the Externally-Driven Capital variance accounts. However, OEB staff submits that the Derecognition variance account should be closed for the 2020-2024 Custom IR term. This issue is discussed in more detail in section 7.2.

Z-factor and Off-Ramps

Toronto Hydro proposed that it continue to be allowed to have Z-factor relief available based on the OEB's generic criteria for such relief.[196] The generic criteria for Z-factor relief is set out in the *Report of the Board on 3rd Generation Incentive Regulation*.[197]

Toronto Hydro also proposed that the OEB's generic policy continue to apply to Toronto Hydro with respect to off-ramps for the 2020-2024 Custom IR term.[198] The OEB's generic policy for off-ramps is discussed in the Rate Handbook and the Chapter 3 Filing Requirements.[199]

OEB staff has no concerns with these proposals.

[195] Exhibit 9 / Tab 1/ Schedule 1 / pp. 10-19.
[196] Exhibit 1B / Tab 4 / Schedule 1 / p. 14.
[197] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors / July 14, 2008 / pp. 35-36 and Appendix A / p. 4-6.
[198] Exhibit 1B / Tab 4 / Schedule 1 / p. 13.
[199] OEB Rate Handbook for Utility Rate Applications / October 13, 2016 / p. 28; and OEB Chapter 3 Filing Requirements for Incentive Rate-setting Applications / July 12, 2018 / p. 30.

Annual Updates during the Custom IR Term

As proposed by Toronto Hydro, OEB staff accepts that the inflation factor should be updated each year in the annual Custom IR update application based on the OEB-approved inflation factor.[200] If the OEB were to change the methodology for calculating the inflation factor or the base productivity factor, the impacts of that methodological change would have to be assessed at the time of the Custom IR update application that immediately follows the change to the methodology. This is the proposed approach suggested by Toronto Hydro.[201]

OEB staff submits that there should be no other annual updates made to the CPCI calculation itself as part of the Custom IR update application.

OEB staff submits that the Group 1 deferral accounts should be brought forward for review and disposition each year, along with the LRAMVA.

In the 2021 Custom IR update application, the Group 2 deferral and variance account balances for 2019 should be brought forward for disposition (as discussed in section 10.2). The audited balances in the Group 2 accounts for 2020-2023 should be brought forward for disposition as part of the 2025 rebasing application.

In addition, changes to the Retail Transmission Service Rates (RTSRs) to reflect the most recent OEB-approved Uniform Transmission Rates (UTRs) should be made each year as part of the Custom IR update application. Similarly, if the OEB orders changes to regulatory charges (e.g. Wholesale Market Service Rate, Rural and Remote Rate Protection, etc.), those changes should also be reflected in the Custom IR update application.

4.2 Is Toronto Hydro's proposed custom scorecard appropriate (Issue 2.2)?

Toronto Hydro proposed 15 additional custom scorecard measures incremental to the OEB's standard performance scorecard. This results in a total of 44 unique measures to be reported annually.[202]

[200] Exhibit 1B / Tab 4 / Schedule 1 / p. 5.
[201] 1B-Staff-18; 1B-Staff-19; and Oral Hearing Transcripts / Vol. 7 / p. 140-142.
[202] Exhibit 1B / Tab 2 / Schedule 1 / p. 6.

The additional custom scorecard measures are summarized in the table below.[203]

Table 8
2020-2024 Custom Performance Scorecard Measures

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	Target
Customer Service	**Customer Satisfaction**	Customers on eBills	Improve
Safety	**Safety**	Total Recorded Injury Frequency	Maintain
		Box Construction Conversion	Improve
		Network Units Modernization	Improve
Reliability	**System Reliability**	SAIDI - Defective Equipment	Maintain
		SAIFI - Defective Equipment	Maintain
		FESI 7 System	Improve
		FESI-6 Large Customers	Maintain
	Asset Management	System Capacity	Maintain
		System Health (Asset Condition) – Wood Poles	Monitor
		Direct Buried Cable Replacement	Improve
Financial	**Cost Control**	Average Wood Pole Replacement Cost	Monitor
		Vegetation Management Cost per Km	Monitor
Environment	**Environment**	Oil Spills Containing PCBs	Improve
		Waste Diversion Rate	Monitor

The full list of scorecard measures (both the standard scorecard measures and the proposed custom scorecard measures) are summarized at Exhibit 1B / Tab 2 / Schedule 1 / Appendix A. Toronto Hydro mapped both the standard and custom scorecard measures to the RRF outcomes.[204]

In developing targets for the 15 custom measures, Toronto Hydro used the most recent five-year historical data (2013-2017) to set the baselines for performance during the 2020-2024 period. The baseline targets (which are shown as historical performance figures) are discussed in detail in Exhibit 2B / Section C2. However, for certain measures (listed as monitor in Table 8), Toronto Hydro stated that the necessary historical data is not available for target setting purposes. For these measures, Toronto

[203] Exhibit 2B / Section C2 / p. 5.
[204] 1B-BOMA-8.

Hydro proposes to monitor and report its results annually and consider this data in developing potential baseline targets to measure future performance.[205]

OEB staff submits that the custom measures proposed by Toronto Hydro reflect a reasonable list of metrics upon which its performance can be measured during the 2020-2024 period. However, with respect to the cost control measures for both the vegetation management cost per kilometre and average wood pole replacement cost, OEB staff submits that the target should be changed to “improve”.

OEB staff submits that cost control is an integral part of a Custom IR application and therefore Toronto Hydro should be expected to improve relative to baselines for the two noted metrics.

With respect to vegetation management cost per kilometre, Toronto Hydro stated that because this is a new custom scorecard measure it does not have experience with the measure and noted that vegetation management is subject to market forces. Therefore, it would not be fair to Toronto Hydro to require it to improve relative to a baseline. However, Toronto Hydro did agree that it has the necessary data to use a baseline for the vegetation management cost per kilometre measure.[206]

OEB staff agrees that many of Toronto Hydro’s capital and maintenance costs are subject to market forces (to varying degrees). OEB staff submits that simply because a proposed custom measure is subject to market forces and is new does not mean that Toronto Hydro should not be expected to improve relative to a baseline. As such, OEB staff submits that the OEB should direct Toronto Hydro to use its most recent historical actual costs for vegetation management to establish a baseline for this measure and change the target from monitor to improve.

With respect to the average wood pole replacement cost measure, Toronto Hydro stated that it does not have the information that it believes is necessary to set an appropriate baseline. Specifically, Toronto Hydro stated that it does not have five consecutive three-year averages upon which to set a baseline. Toronto Hydro noted that this measure could have volatility year-over-year.[207]

[205] Exhibit 2B / Section C2 / pp. 4-5.
[206] Oral Hearing Transcripts / Vol. 2 / pp. 16-17.
[207] Oral Hearing Transcripts / Vol. 2 / pp. 14-15.

OEB staff submits that while it is true that Toronto Hydro does not have five consecutive three-year averages, Toronto Hydro does have five years of historical data upon which to set a baseline (2014-2018).[208] OEB staff is of the view that five years of historical data is a sufficient level of data to use in setting a baseline for this measure given the importance of cost control within a Custom IR framework. Toronto Hydro should be required to use its most recent historical actual costs for pole replacement to establish a baseline for this measure and change the target from monitor to improve.

5. Rate Base and Capital Plan (Issue 3.0)

5.1 Are the proposed 2020-2024 rate base amounts (including the working capital allowance amounts) reasonable (Issue 3.1)?

Toronto Hydro's proposed rate base, including the application updates discussed in Undertaking J1.2, are set out in the following table.[209]

Table 9
2020-2024 Rate Base

Rate Base ($M)	2020	2021	2022	2023	2024
Average Property, Plant & Equipment (PP&E) NBV	$ 4,369.7	$ 4,601.9	$ 4,844.4	$ 5,128.5	$ 5,393.2
WCA	$ 222.9	$ 227.2	$ 232.0	$ 237.0	$ 243.1
Rate Base	**$ 4,592.6**	**$ 4,829.1**	**$ 5,076.4**	**$ 5,365.5**	**$ 5,636.3**

OEB staff accepts the updated working capital allowance (WCA) amounts shown in Undertaking J1.7 and as reflected in Table 9. This includes the updates to the WCA discussed in Undertaking J1.2.[210] OEB staff accepts Toronto Hydro's proposal to update the electricity prices used in the WCA calculation at the draft rate order stage of the proceeding.[211]

[208] Undertaking JTC2.11.
[209] Undertaking J1.7.
[210] Updated to align the cost of power expense forecast with the value resulting from the OEB's Appendix 2-Z and for changes to the OEB's Customer Service Rules.
[211] Undertaking J1.2.

OEB staff has two direct concerns with the proposed rate base amounts for 2020-2024. First, OEB staff submits that an average of monthly averages approach should be used for the calculation of rate base. Second, a permanent disallowance to rate base should be made with respect to the Copeland Phase 1 project.

OEB staff's submissions with respect to the forecast capital budget will also have an impact on the rate base amounts.

Average of Monthly Averages Approach for the Calculation of Rate Base

In Toronto Hydro's calculation of rate base, it uses the half-year rule for the inclusion of in-service additions (based on annual information).[212] However, the depreciation expense that is included in the rate base calculation is not determined using the half-year rule. Instead, the depreciation expense included in the rate base calculation is based on monthly information.[213]

OEB staff submits that there is a disconnect within the rate base calculation in terms of how in-service additions and depreciation are valued. OEB staff submits that this approach, whereby in-service additions and depreciation expense are not valued equally in a given year should not continue given that Toronto Hydro has the information necessary to better align the two.

OEB staff notes that Toronto Hydro has monthly information available for both in-service additions and depreciation expense.[214] Toronto Hydro stated, with respect to depreciation expense, that using monthly information provides a more accurate forecast of depreciation expense than the half-year rule approach.[215] It is OEB staff's position that using monthly information for in-service additions would similarly provide a more accurate forecast of rate base than the half-year rule approach.

Toronto Hydro argued that it should be allowed to continue with its existing approach as it was previously approved and is in accordance with the OEB's Chapter 2 Filing Requirements.[216] OEB staff submits that Toronto Hydro should calculate its rate base

[212] Exhibit 2A / Tab 1 / Schedule 1 / p. 2.
[213] 2A-Staff-52(b); and Undertaking JTC 1.1. Toronto Hydro stated that the depreciation expense calculated using the half-year rule is $11.7 million higher than the amount it has proposed in its application (which is based on monthly information).
[214] Undertaking J1.9 / Appendix A.
[215] JTC1.1 / pp. 1-2.
[216] Argument-in-Chief / p. 20.

based on an average of monthly averages approach. It is OEB staff's view that, in the circumstances where a utility has forecast information available to perform the rate base calculation using monthly information, this approach would result in the more accurate forecast of rate base than applying the half-year rule. OEB staff also notes that the average of monthly averages approach is listed as an alternative approach in the OEB's Chapter 2 Filing Requirements. In addition, OEB staff notes that the former Union Gas Limited and Enbridge Gas Distribution Inc. used an average of monthly averages approach to calculate rate base in their respective 2013 rebasing applications.[217]

Toronto Hydro has provided the monthly information necessary to calculate rate base using an average of monthly averages approach in Undertaking J1.9.[218] OEB staff calculates, based on Undertaking J1.9[219], that the rate base in each year during the 2020-2024 period would be on average approximately $74 million lower than the proposed rate base amounts. The main revenue requirement impact of this proposed methodological change will be on the cost of capital associated with rate base (with a related impact on PILs) as the depreciation expense is already forecast on a monthly basis (and included in the revenue requirement using the monthly information). OEB staff estimates that the revenue requirement impact of this change is approximately a $21 million reduction (excluding PILs) for the 2020-2024 Custom IR term.

The reason for the decrease in the rate base amounts that results from the use of an average of monthly averages approach is that Toronto Hydro's in-service additions are weighted towards the end of the year (in each year during the 2020-2024 term).[220] Toronto Hydro also stated that the weighting of in-service additions toward the end of a year is expected to continue going forward, at least with respect to its distribution capital projects, due to its historical construction cycle.[221]

[217] EB-2011-0210 / Exhibit B3 / Tab 2 / Schedule 1/ p. 1; and EB-2011-0354 / Exhibit B3 / Tab 1 / Schedule 2.
[218] There are some small differences in the total depreciation expense provided in Undertaking J1.9 relative to Undertaking J8.5. The working capital allowance was also not updated in Exhibit J1.9, however, the average of monthly average approach for the calculation of rate base does not impact the working capital allowance.
[219] OEB staff notes that the rate base amounts will change if its other arguments with respect rate base and capital expenditures are accepted by the OEB.
[220] Undertaking J1.9 / Appendix A.
[221] Oral Hearing Transcripts / Vol. 1 / pp. 180-181.

Copeland Phase 1 Disallowance

The total cost of the Copeland Phase 1 project is set out in the table below.[222]

Table 10
Copeland Phase 1 – Cost Variance

Item	Description	OEB Approved Cost ($M)	Current Forecast – 2018 ($M)
Station Cost	**Land**	$5.6	$5.6
	Building	$53.3	$66.7
	Substation Equipment	$52.6	$45.5
	Distribution Modification	$2.3	$2.3
	Design & Construction PM – Substation	$6.2	$26.1
Tunnel	**Design & Construction PM**	$0.6	$3.5
	Construction	$14	$14.4
Hydro One	**Capital Contribution**	$60.4	$39.9
	Total Cost:	**$195.0**	**$204.0**

The project was originally expected to go into service in 2016 and is now forecast to go into service in 2019.[223]

The total cost variance on the project is $9 million (4.6%) between the actual cost and the amount approved by the OEB in the 2015-2019 decision.[224] However, there was a very significant change in the capital contribution paid to Hydro One in respect of this project. When looking at the project in terms of the work that Toronto Hydro completed (i.e. removing the capital contribution from both the OEB-approved and actual amounts), the OEB-approved amount was $134.6 million and the actual cost was $164.1 million. This represents an overspend on Toronto Hydro's portion of the project of $29.5 million (21.9%). The cost of the Copeland Phase 1 project are shown in the below table (with the capital contribution removed).

[222] 2B-Staff-95 / p. 4.
[223] U-Staff-166.3 / Appendix C.
[224] 2B-Staff-95 / p. 4.

Table 11
Copeland Phase 1 – Cost Variance (with capital contribution removed)

Item	Description	OEB Approved Cost ($M)	Current Forecast – 2018 ($M)
Station Cost	**Land**	$5.6	$5.6
	Building	$53.3	$66.7
	Substation Equipment	$52.6	$45.5
	Distribution Modification	$2.3	$2.3
	Design & Construction PM – Substation	$6.2	$26.1
Tunnel	**Design & Construction PM**	$0.6	$3.5
	Construction	$14	$14.4
	Total Cost:	**$134.6**	**$164.1**

Toronto Hydro explained that while the Hydro One contribution was lower than approved (due to Hydro One installing six high voltage breakers as opposed to the originally planned ten high voltage breakers), Toronto Hydro incurred additional costs because of the modification to the scope of work that Hydro One completed.[225] Toronto Hydro also discussed further delays caused by Hydro One that required Toronto Hydro to energize the project in two phases.[226]

OEB staff agrees with Toronto Hydro that a portion of the overall cost overrun on the part of the project that it was responsible for completing was caused by Hydro One modifying its plan with respect to this project.

However, OEB staff does not believe that the transfer of work between Hydro One and Toronto Hydro was the entire cause of the cost overrun on Toronto Hydro's side of the project.

Toronto Hydro discussed a number of factors that caused increased costs and scheduling delays in response to an interrogatory. The list includes: unusually adverse weather events, challenging site conditions, logistical challenges, and contractor performance.[227]

[225] Technical Conference Transcripts / Vol. 1 / p. 36; and Oral Hearing Transcripts / Vol. 1 / pp. 116-118.
[226] Oral Hearing Transcripts/ Vol. 1 / pp. 118-119.
[227] 2B-Staff-95(b).

With respect to the adverse weather events, OEB staff notes that Copeland Phase 1 was under construction during the ice storm of 2013-2014. With respect to the contractor issues, OEB staff notes that Toronto Hydro's general contractor entered creditor protection in January 2018. As such, the contractor's pace of work in the first half of 2018 was curtailed. This adversely impacted the project schedule and costs. It also required Toronto Hydro to mobilize another general contractor to complete the required work.[228] Based on the evidence in this proceeding, as summarized above, OEB staff is of the view that the adverse weather events experienced and the contractor issues should be considered outside of management's control.

In contrast, the challenging site conditions are firmly within management's control. Toronto Hydro stated that the proximity to the heritage Roundhouse required special care and protection of the adjacent historic building.[229] OEB staff understands that there would have been challenges with respect to the site conditions. However, these are challenges that Toronto Hydro should have known about in the planning stages (and included in the forecasted budget) for this major capital project. Toronto Hydro should have planned for these difficulties and taken effective actions to mitigate the cost overruns and schedules delays that occurred due to the challenging site conditions.

Similarly, the logistical challenges encountered by Toronto Hydro are also properly considered within management's control. Toronto Hydro notes that it was unable to secure a sufficient amount of road space for its requirements (which required, a twice daily "bump-out" of the perimeter fence). In addition, there were logistical challenges regarding the delivery of two 155 tonne transformer tanks.[230] OEB staff submits that these logistical challenges should have been apparent to Toronto Hydro in the planning stages (and included in the forecasted budget) for this major capital project. Toronto Hydro should have better managed these logistical challenges during the construction of the project in order to avoid cost overruns and schedule delays that occurred on an actual basis.

As a result of the two noted challenges, which OEB staff submits were within management's control, cost overruns occurred on the Copeland Phase 1 project. Toronto Hydro seeks recovery of these cost overruns from ratepayers as part of the current proceeding.

[228] 2B-Staff-95(b).
[229] 2B-Staff-95(b).
[230] 2B-Staff-95(b).

OEB staff submits that the portion of the cost overrun related to the Copeland Phase 1 project that was caused by the factors that were within management's control should not be allowed to be recovered from ratepayers as these costs were imprudently incurred. OEB staff believes that an appropriate disallowance for the imprudent costs incurred related to the challenging site conditions and logistical challenges is $5 million. As such, $5 million should be permanently removed from the 2020 opening rate base amount.[231] OEB staff estimates that the revenue requirement impact of this rate base disallowance is approximately $2.5 million for the 2020-2024 Custom IR term.[232]

In addition, OEB staff notes that there is ongoing litigation with respect to the Carillion insolvency.[233] OEB staff submits that a potential outcome of that process is that Carillion is required to make a payment to Toronto Hydro. If that were to occur, OEB staff submits that the payment should be considered an offset to rate base. During the Custom IR period, the revenue requirement impact of the reduction to rate base (associated with the payment amount) should be recorded in a new deferral account (the Carillion Insolvency Payments Receivable Account). At the time of the next rebasing, Toronto Hydro should remove the amount related to the litigation payment from rate base on a permanent basis and the account can be closed. OEB staff submits that the CRRRVA should not be used to record this amount. This potential payment amount is related to capital that was placed in-service during the 2015-2019 Custom IR term. As such, it would not be appropriate for this offset to rate base to be mixed with capital-related revenue requirement variances that occur during the 2020-2024 Custom IR term. If it were included in the CRRRVA, there is the potential scenario whereby the revenue requirement impact of the offset to rate base (related to the payment amount) would not be refunded to ratepayers.[234]

[231] OEB staff understands that the entire cost of the project is reflected in the 2020 opening balance given the forecasted in-service date of 2019.
[232] OEB staff notes that the 2019 revenue requirement impact of this disallowance should be reflected in the 2019 CRRRVA balance as appropriate. As discussed, in section 10.2, OEB staff submits that the 2019 Group 2 deferral and variance account balances should be disposed as part of the 2021 Custom IR update application.
[233] Oral Hearing Transcripts / Vol. 1 / p. 165.
[234] This would occur if Toronto Hydro's actual capital-related revenue requirement is higher than the OEB-approved capital-related revenue requirement (over the 2020-2024 period).

5.2 Is the level of proposed 2020-2024 capital expenditures and capital in-service additions arising from the distribution system plan appropriate, and is the rationale for planning and pacing choices, including trade-offs between capital and operating costs, appropriate and adequately explained (Issue 3.2)?

Toronto Hydro's proposed net capital expenditures are set out in the following table[235]:

Table 12
2020-2024 Capital Expenditures

($M)	2020	2021	2022	2023	2024	Total
System Access	$ 92.80	$ 93.30	$ 93.90	$ 106.00	$ 116.40	**$ 502.40**
System Renewal	$ 307.60	$ 325.70	$ 323.10	$ 339.00	$ 325.60	**$1,621.00**
System Service	$ 34.60	$ 60.10	$ 71.30	$ 33.60	$ 38.50	**$ 238.10**
General Plant	$ 79.60	$ 93.70	$ 89.00	$ 77.70	$ 85.20	**$ 425.20**
Other	$ 7.00	$ 9.00	$ 9.80	$ 9.50	$ 8.70	**$ 44.00**
Sub-Total	$ 521.60	$ 581.80	$ 587.10	$ 565.80	$ 574.40	**$2,830.70**
Less Non-Rate Regulated Utility Assets	$ (4.40)	$ (3.10)	$ (3.20)	$ (3.30)	$ (3.50)	**$ (17.50)**
Total	**$ 517.20**	**$ 578.70**	**$ 583.90**	**$ 562.50**	**$ 570.90**	**$2,813.20**

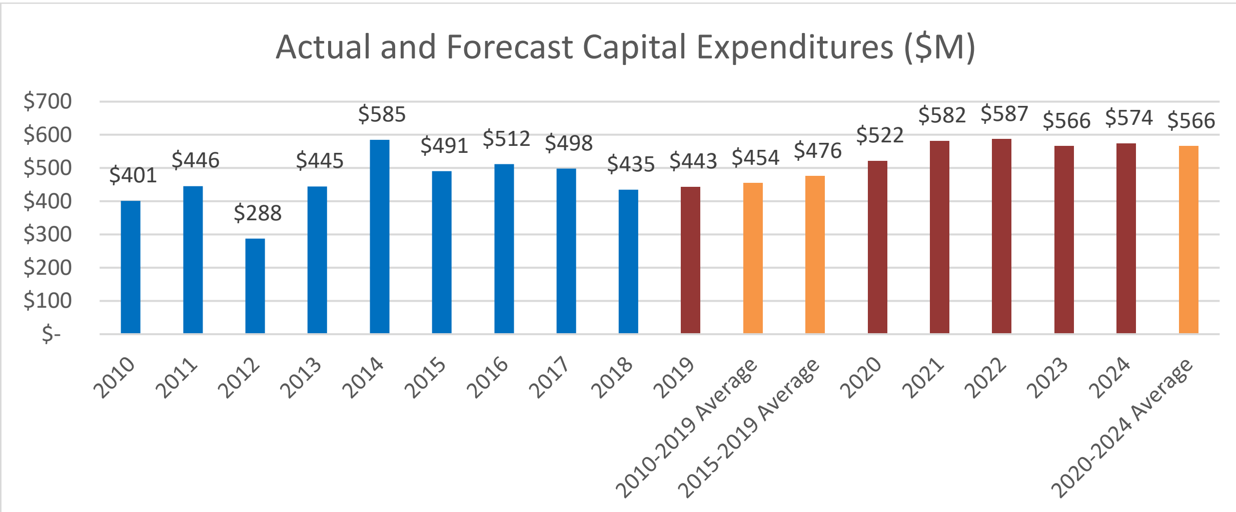
The proposed 2020-2024 capital expenditures of $2,830.7 million compares to approved capital expenditures for the 2015-2019 period of $2,240.4 million.[236] This is an increase of $590.3 million (26.3%). The also compares to actual capital expenditures for the 2015-2019 period of $2,379.4 million.[237] This is an increase of $451.3 million (19.0%).

OEB staff notes that Toronto Hydro has made significant investments in its system since at least 2010. The proposed capital expenditures for the 2020-2024 period are a

[235] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2. In U-Staff-168 / Table 2, Toronto Hydro proposed a $3.2 million increase to capital expenditures due to carryover projects from the 2015-2019 Custom IR term. OEB staff has included that $3.2 million increase in the relevant categories based on U-Staff-168 / Table 2.
[236] U-Staff-171 / Appendix A. OEB staff is using the capital expenditure amounts prior to the removal of the non-rate regulated utility assets for this comparison as it does not believe that there are approved capital expenditure amounts with the non-rate regulated utility assets removed available on the record of this proceeding. OEB staff notes that the removal of the non-rate regulated assets would have nearly no impact on this high-level analysis.
[237] Exhibit U / Tab 2 / Schedule 2 / p. 3. Note that the 2019 capital expenditures are still considered forecast.

continuation of that significant capital spending. Below is a figure showing Toronto Hydro's actual and forecast capital expenditures for the 2010-2024 period.[238]

Figure 2
2010-2024 Actual and Forecast Capital Expenditures



Toronto Hydro's proposed in-service additions associated with its proposed capital expenditures (and CWIP) are set out in the table below.[239]

Table 13
2020-2024 In-Service Additions

($M)	2020	2021	2022	2023	2024	Total
In-Service Additions	$ 539.90	$ 475.00	$ 587.40	$ 590.50	$ 583.60	**$2,776.40**

Toronto Hydro stated that its proposals reflect the "minimum level of investment" needed for its distribution system.[240] Specifically, with respect to its capital plan, Toronto Hydro stated that its plan is "a restrained plan that represents a minimum level of investment necessary to maintain average reliability and customer service performance

[238] 2010-2013: EB-2014-0116 / Exhibit 2B / Schedule 00 / p. 26; 2014: 2B-SEC-46 / Appendix A; 2015-2024: U-Staff-168 / Appendix B / p. 8.
[239] Undertaking J1.7.
[240] Argument-in-Chief / Introduction p. 1, 6, 23, 26, 31-32.

and deliver targeted improvements for customers experiencing below average service."[241] OEB staff disagrees.

OEB staff has a number of specific concerns with the proposed capital expenditures and related in-service additions for the 2020-2024 period. Specifically, OEB staff submits that a reduction to the total 2020-2024 capital expenditures of $246.8 million is appropriate. The proposed reductions are listed below:

- Customer Connections - $14.7 million
- System Renewal (excluding area conversions and reactive capital) - $162.3 million
- Area Conversions - $20 million
- Control Operations Reinforcement - $40.2 million
- Fleet and Equipment Services - $4.2 million
- AFUDC - $5.4 million.

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). OEB staff estimates that the total impact of the proposed capital expenditure reductions on revenue requirement is between $40 million and $60 million over the 2020-2024 Custom IR term depending on the precise impact on in-service additions.

OEB staff also submits that its arguments with respect to increasing the stretch factor applicable to capital in section 4.1 will require Toronto Hydro to find incremental capital-related efficiencies relative to its proposal over the 2020-2024 Custom IR term.

OEB staff submits that the methodology used for calculating in-service additions (i.e. converting capital expenditures and CWIP to in-service amounts) is appropriate for the 2020-2024 Custom IR term but should be improved for the next rebasing application.

OEB staff also submits that Toronto Hydro's customer-specific ESS program is not a distribution activity. However, it appears to be allowable under the exemption established in section 71(3) of the OEB Act. Accordingly, OEB staff submits this program must be accounted for separately from distribution activities. This argument has no impact on the level of net capital expenditures (or rate base) as the customer-specific energy storage systems are proposed to be fully contributed by the customer.

[241] Argument-in-Chief / p. 23.

The Distribution System Plan and Capital Expenditures

Toronto Hydro filed a comprehensive Distribution System Plan (DSP) in accordance with Chapter 5 of the OEB's filing requirements.[242] The DSP filed by Toronto Hydro provided all the information required by the noted filing requirements. Specifically, the DSP provided detailed information with respect to Toronto Hydro's asset management principles and methodologies, its coordination with third-parties, performance measurement, and about each of its proposed capital programs.

In addition, as part of the DSP, Toronto Hydro explained how customer engagement informed its proposed capital plan.[243] Toronto Hydro noted that its customers were generally supportive of its proposed capital plan.[244] As discussed in section 3.1, in a similar manner to how Toronto Hydro considers customer feedback in its planning process, the OEB should consider the feedback from Toronto Hydro's customers as one input in its decision-making process along with all the other evidence that has been filed in this proceeding.

OEB staff's detailed review of the DSP, interrogatory responses, testimony at both the technical conference and the oral hearing results in its conclusion that the proposed capital budget is overstated and certain targeted reductions are necessary.

The following sections will provide a high-level summary of each category of proposed capital spending and OEB staff's submissions on only those areas where it believes reductions are required.

System Access

The table below provides the proposed net capital expenditures for each program within the system access category.[245]

[242] OEB Chapter 5 – Consolidated Distribution System Plan Filing Requirements for Rate Applications, July 12, 2018.
[243] Exhibit 2B / Section E2 / pp. 2-8.
[244] Exhibit 2B / Section E2 / p. 7.
[245] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.

Table 14
2020-2024 System Access Capital Expenditures

Programs ($M)	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
Customer and Generation Connections	$ 42.9	$ 43.9	$ 44.8	$ 45.6	$ 46.3	**$ 223.4**
Externally Initiated Plant Relocations & Expansion	$ 11.4	$ 20.8	$ 4.6	$ 4.7	$ 4.5	**$ 46.1**
Generation Protection, Monitoring and Control	$ 3.7	$ 2.3	$ 2.4	$ 2.5	$ 2.7	**$ 13.6**
Load Demand	$ 11.3	$ 11.4	$ 18.5	$ 22.6	$ 23.6	**$ 87.5**
Metering	$ 23.6	$ 14.8	$ 23.6	$ 30.6	$ 39.2	**$ 131.8**
System Access Total	**$ 92.8**	**$ 93.3**	**$ 93.9**	**$ 106.0**	**$ 116.4**	**$ 502.4**

OEB staff has no specific concerns with the capital budgets for any of the programs in the system access category with the exception of the Customer and Generation Connections program.

Customer and Generation Connections

OEB staff submits that a reduction to the proposed Customer and Generation Connections program budget of $14.7 million (6.6%) for the 2020-2024 period is appropriate.

The Customer and Generation Connections program includes the costs of system investments that are required to provide customers with access to the system.

The program covers two main categories of costs: (a) customer connections; and (b) generation connections. The net cost of the program (after capital contributions) is entirely driven by the customer connection segment (as the cost of generation connections are fully contributed by the connecting generator) as shown in the table below.[246]

[246] Exhibit 2B / Section E5.1 / p. 14.

Table 15
Historical and Proposed Customer and Generation Connections Net Capital Expenditures

($M)	Actual			Bridge		Forecast					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
Customer Connection	$32.6	$39.6	$22.1	$44.8	$37.6	$42.9	$43.9	$44.8	$45.6	$46.3	$223.4
Generation Connection	$(0.9)	$0.4	$(0.2)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**$31.7**	**$40.1**	**$21.9**	**$44.8**	**$37.6**	**$42.9**	**$43.9**	**$44.8**	**$45.6**	**$46.3**	**$223.4**

The proposed 2020-2024 capital contributions in the customer connection segment were based on a weighted average of 2013-2017 customer contributions.[247]

Toronto Hydro provided updated gross capital expenditures and capital contributions for the customer connections segment of the program based on the most recent available information (which includes 2018 actuals). The amounts resulting from this update are set out in the table below.[248]

Table 16
2020-2024 Updated Forecast Customer Connection Costs

($M)	2020	2021	2022	2023	2024	Total
Gross Expenditures	$77.1	$78.7	$80.2	$81.9	$83.5	**$401.4**
Capital Contributions	$(37.0)	$(37.8)	$(38.5)	$(39.3)	$(40.1)	**$(192.7)**
Net	**$40.1**	**$40.9**	**$41.7**	**$42.6**	**$43.4**	**$208.7**

OEB staff submits that the most recent data available (2018 actuals) should be used in the forecasting methodology to determine the net costs for this program. As such, the total net cost of the program should be reduced from $223.4 million to $208.7 million (a reduction of $14.7 million or 6.6%).

[247] 2B-Staff-78(b).
[248] Undertaking J1.6.

System Renewal

The table below provides the proposed capital expenditures for each program within the system renewal category.[249]

Table 17
2020-2024 System Renewal Capital Expenditures

($M)	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
Area Conversions	$ 41.9	$ 47.2	$ 46.3	$ 50.4	$ 35.6	**$ 221.3**
Network System Renewal	$ 18.6	$ 19.3	$ 18.5	$ 17.7	$ 18.3	**$ 92.4**
Reactive and Corrective Capital	$ 61.2	$ 62.4	$ 63.5	$ 64.4	$ 65.8	**$ 317.2**
Stations Renewal	$ 28.0	$ 35.3	$ 29.4	$ 27.0	$ 22.4	**$ 142.0**
Underground Renewal - Downtown	$ 15.1	$ 22.5	$ 23.9	$ 30.0	$ 30.6	**$ 122.0**
Underground Renewal - Horseshoe	$ 93.0	$ 88.7	$ 90.3	$ 93.1	$ 95.2	**$ 460.3**
Overhead System Renewal	$ 49.8	$ 50.4	$ 51.3	$ 56.5	$ 57.7	**$ 265.7**
System Renewal Total	**$ 307.6**	**$ 325.7**	**$ 323.1**	**$ 339.0**	**$ 325.5**	**$ 1,621**

The system renewal budget is primarily designed to ensure the continued proactive investment in Toronto Hydro's system required to manage safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers.[250]

OEB staff submits that the planned system renewal budget (which OEB staff defines for these purposes to exclude area conversions and reactive & corrective capital) should be reduced by 15%. This results in a reduction of $162.3 million.[251]

OEB staff also submits that the area conversion budget should be reduced by approximately $20 million (a reduction of 9%).

[249] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.
[250] Exhibit 2B / Section E2 / p. 21.
[251] Calculated as total system renewal budget ($1,621 million) minus area conversion budget ($221.3 million) and reactive and corrective capital budget ($317.2 million) equals $1,082.3 million * 15%.

Planned System Renewal

The planned system renewal budget (excluding area conversions and reactive & corrective capital budgets[252]) is $1,082.3 million. OEB staff submits that a 15% reduction ($162.3 million) to the planned system renewal is appropriate for the following reasons:

- Toronto Hydro has not fully transitioned to its new asset condition assessment (ACA) methodology upon which it makes capital investment decisions. As such, the outputs of the ACA, which are used, in part, to develop the capital plans, are not fully developed and the proposed planned asset replacements could be overstated.

- Toronto Hydro has not provided the evidence necessary to confirm that its planned system renewal investments have been targeted optimally in the past (2015-2019 Custom IR term) or will be targeted efficiently over the proposed 2020-2024 Custom IR term.

- Toronto Hydro is considered a developing utility by UMS in terms of the maturity of its asset management capabilities. As such, the capital plans are based on asset management capabilities that are not fully mature.

- Even if the OEB were to fully accept that the outputs of Toronto Hydro's ACA methodology should be relied on, there is a clear over-investment proposed for the Underground Horseshoe Renewal program relative to the health index scores for certain asset classes.

- The forecast planned system renewal budget is overstated as it does not appropriately account for the amount of planned work that will be completed reactively (and the costs of which will be covered within the reactive capital budget).

[252] OEB staff has made a separate submission with respect to the area conversion program and the issues that OEB staff has with the planned capital are not directly applicable to the reactive capital budget.

Asset Condition Assessment

Toronto Hydro has transitioned from the ACA methodology originally adopted in 2008 to a new ACA model that it believes provides more accurate and comprehensive condition-based analytics, which better supports expenditure planning over longer time horizons. Toronto Hydro stated that after encountering certain limitations in its existing weighted average condition assessment methodology, it sought a more sophisticated condition methodology that included projection modeling capabilities. Toronto Hydro has transitioned to the Common Network Asset Indices Methodology (CNAIM).[253]

The new ACA combines observable asset condition variables with age to generate health index (HI) scores that relate the overall asset condition to the asset's remaining useful life. This allows Toronto Hydro to place assets along an asset health continuum, which is divided into five HI bands (HI1 to HI5 – HI5 representing assets in the worst condition).[254]

Toronto Hydro relies on its ACA as part of its capital planning process to support tactical and strategic investment planning decisions. Specifically, Toronto Hydro uses the outputs of its ACA to support the development of investment plans within its Investment Planning and Portfolio Reporting process.[255]

Toronto Hydro's Investment Planning and Portfolio Reporting process uses the outputs from the Asset Needs Assessment to develop program-level expenditure plan proposals for 2020-2024 that would support the utility's asset management outcome objectives.[256]

Overall, it is clear that the outputs of the ACA (the HI scores) are an important input to developing the capital plans (and associated capital expenditures) proposed as part of the current proceeding. The ACA inputs are being directly relied upon to support Toronto Hydro's requests for planned system renewal capital spending.

OEB staff submits that Toronto Hydro has not fully transitioned to the new ACA methodology and certain key aspects of the methodology have not been implemented by Toronto Hydro in advance of the current proceeding.

[253] Exhibit 2B / Section D1 / pp. 26-27.
[254] Exhibit 2B / Section D1 / p. 13.
[255] Exhibit 2B / Section D / Appendix C / p. 2.
[256] Exhibit 2B / E2 / p. 16.

Toronto Hydro stated that its immediate objective in moving to the new ACA was to replace the functionality of the previous ACA, which did not include a consequence of failure or asset criticality component. Going forward, in addition to developing the incremental capability to convert an HI score to probability of failure, Toronto Hydro intends to explore the consequences of failure and criticality aspects of the CNAIM. In addition, Toronto Hydro will examine opportunities to derive additional value from its existing Feeder Investment Model (FIM) by connecting it with, or subsuming it within, the CNAIM approach to asset risk evaluation.[257]

OEB staff notes that Toronto Hydro has only implemented one aspect of the new ACA methodology, which is to calculate current and future HI scores for its assets. However, even for that aspect of the CNAIM methodology, it has not fully populated the model to allow for the most accurate calculation of the HI scores. In calculating the HI scores, Toronto Hydro has set health score modifiers and duty factors, but has not set asset-specific location and reliability modifiers (default modifiers have been utilized instead).[258]

Toronto Hydro has not implemented the aspects of the CNAIM methodology that provide incremental functionality relative to the previous ACA. Specifically, Toronto Hydro has not converted the HI scores into a probability of failure nor has it calculated the consequence of failure.[259]

OEB staff notes that Toronto Hydro does perform risk assessment in terms of probability of failure and consequence of failure outside of the ACA methodology. Toronto Hydro relies on its predictive failure modeling approach and historical reliability analysis to determine the probability of failure.[260] In terms of evaluating the consequences of failure, Toronto Hydro looks at a wide range of factors (including customer needs and reliability, environment, safety, public policy, and financial considerations).[261] The risk analysis undertaken considers the probability and consequence of failure using a combination of qualitative and quantitative methods (including the FIM for economic risk-based analysis).[262]

[257] Exhibit 2B / Section D / Appendix C / p. 6.
[258] Oral Hearing Transcripts / Vol. 3 / pp. 131-132.
[259] Oral Hearing Transcripts / Vol. 3 / pp. 133.
[260] Exhibit 2B / Section D3 / pp. 22-24.
[261] Exhibit 2B / Section D3 / pp. 25-29.
[262] Exhibit 2B / Section D3 / p. 30.

While Toronto Hydro does perform risk-based analysis, it is not completed in a centralized, formal manner. Toronto Hydro noted that depending on the program, the planners responsible for determining the level of capital expenditures required may place additional weight on the different risk management approaches available.[263] Toronto Hydro specifically stated that it does not have a single algorithm upon which it determines how to best reduce asset risk through its capital investments.[264] OEB staff submits that a centralized approach to asset risk management is crucial to ensuring that only investments that are most cost-effective at reducing failure risk are actually being made and assets are not being replaced prior to their optimal end of useful life.

OEB staff submits that Toronto Hydro seems to agree that there is value in determining asset risk through a single methodology as it intends to develop the capability to convert its HI scores to a probability of failure and explore the consequences of failure aspects of the CNAIM (including potentially subsuming its existing risk evaluation tool in the CNAIM) going forward.[265]

In addition, one of the tools Toronto Hydro uses to evaluate asset risk, the economic risk-based analysis (which leverages the FIM to produce the necessary calculations), relies on inputs from Toronto Hydro's Customer Interruption Cost (CIC) study.[266] The CIC is an important input in the economic risk-based analysis that Toronto Hydro undertakes. The CIC used in the analysis was intended to be updated in advance of the current proceeding but a revised CIC study was never completed.[267] Therefore, one of the tools that Toronto Hydro currently uses to evaluate risk relies on outdated information that Toronto Hydro had intended to update in advance of the current proceeding.

OEB staff submits that in the absence of a centralized approach to risk management and the full implementation of the new ACA (including using all the relevant modifiers in the calculation of the HI scores), the proposed capital expenditures may be overstated as they do not necessarily reflect the true needs for capital intervention.

OEB staff also submits that Toronto Hydro should be directed to complete the CIC study that it had intended to complete in advance of the current proceeding prior to its next

[263] 2B-Staff-67(e).
[264] Oral Hearing Transcripts / Vol. 1 / p. 74.
[265] Exhibit 2B / Section D / Appendix C / p. 6.
[266] Exhibit 2B / Section D3 / p. 30.
[267] Oral Hearing Transcripts / Vol. 1 / pp. 84-86.

cost-based application. Toronto Hydro should also explain, at that time, how the outputs of the CIC study are used in the context of the CNAIM methodology.

Targeting of System Renewal Investment

OEB staff notes that Toronto Hydro transitioned its ACA from the previous methodology to the CNAIM in 2017. Therefore, the last year for which it has asset condition data based on the previous ACA is 2016.[268] A comparison of the previous ACA and new ACA methodologies shows that, for nearly all asset classes, the quantity of assets in the lowest two categories (poor / very poor vs. HI4 and HI5) has grown significantly.[269]

Toronto Hydro will have invested approximately $856.8 million over the 2015-2019 period in its planned system renewal programs (excluding area conversions and reactive capital).[270] OEB staff submits that the change in the methodology has made it difficult to determine whether the system renewal capital investments made over the 2015-2019 Custom IR term approved by the OEB have been targeted effectively and resulted in a reduction in the quantity of assets that are in the worst condition. As such, the OEB has no assurances that the 2015-2019 system renewal investments have been targeted effectively in terms of reducing the number of assets that are in the poorest condition.

OEB staff also notes, as discussed previously, Toronto Hydro does not have a centralized methodology for determining how to best approach reducing asset risk through system renewal investment. This calls into question the pacing and prioritization of system renewal investment during the 2020-2024 Custom IR term.

Furthermore, Toronto Hydro cannot show how the proposed system renewal capital investments will impact the health of the asset population at the end of the 2020-2024 Custom IR term. Toronto Hydro has not calculated future HI scores based on its proposed investment plan as it requires a methodology to identify how the different capital programs will be allocated to the different asset classes.[271] In addition, Toronto Hydro's proposed capital plan is forecasted to result in essentially flat reliability over the Custom IR term.[272]

[268] Oral Hearing Transcripts / Vol. 1 / p. 63.
[269] Exhibit K1.2 / p. 46; and Oral Hearing Transcripts / Vol. 1 / p. 63.
[270] Exhibit U / Tab 2 / Schedule 2 / Appendix A.
[271] Oral Hearing Transcripts / Vol. 4 / pp. 133-134.
[272] U-SEC-105; and Oral Hearing Transcripts / Vol. 3 / p. 11.

Toronto Hydro's proposed planned system renewal capital expenditures over the 2020-2024 term are approximately $1,082.3 million[273] (excluding area conversions and reactive capital) and the OEB has no ability to determine, based on the evidence, whether these investments will actually target the worst condition assets over the Custom IR term.

OEB staff is very concerned that Toronto Hydro will have invested approximately $1,939.1 million in planned system renewal (excluding area conversions and reactive capital) over the 2015-2024 period, if its application is approved as filed, and the OEB has no assurances that the investment is targeted efficiently at the worst condition assets on the system.

Asset Management Capabilities

Toronto Hydro's asset management capabilities were reviewed by the UMS.[274] UMS found that Toronto Hydro scored an average asset management maturity level of 2.1 across the 11 (of a total 24) ISO 55001 domains that were reviewed as part of UMS' report.[275]

An asset management maturity level of 2.1, based on the ISO 55001 standards, reflects a maturity level that is classified as "developing." A maturity level of 3 is considered "competence" and a maturity level of 4 is "best practice." [276]

While, UMS has stated that Toronto Hydro exceeds the North America average level of maturity[277], it is still, based on the ISO 550001 standards, classified as a developing utility. OEB staff submits that in the OEB's consideration of Toronto Hydro's proposed capital expenditures, which rely heavily on the information processed through its asset management processes, it should note that Toronto Hydro's capabilities in this respect are still considered "developing" based on the relevant standard.

In OEB staff's view, exceeding the North American average level of maturity is not sufficient to support a continuously increasing capital budget, especially in light of the utility's declining cost performance discussed in section 4.1.

[273] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.
[274] Exhibit 2B / Section D / Appendix A.
[275] Exhibit 2B / Section D / Appendix A / p. 7.
[276] Oral Hearing Transcripts, Vol. 9 / pp. 133.
[277] Exhibit 2B / Section D / Appendix A / p. 5.

Proposed Investment in the Underground Renewal - Horseshoe Program is too high

Toronto Hydro's overall capital expenditure plan is designed to maintain asset failure risk as represented by leading indicators like asset condition (resulting from the ACA) and to maintain system reliability at current levels over the 2020-2024 period.[278]

Toronto Hydro provided HI scores for its asset classes in 2024 under a no investment scenario.[279] Even if the OEB were to accept that Toronto Hydro's HI scores are entirely accurate and that it has efficiently targeted investment to best manage asset risk, which OEB staff has already submitted should not be accepted, Toronto Hydro's proposed investments in the Underground Horseshoe program (which is the largest program in the system renewal category) are higher than the stated need.

Toronto Hydro proposed to replace, on a planned basis, 1,941 transformers in the Underground Renewal - Horseshoe program over the 2020-2024 period and only 1,179 replacements are required to maintain the number of transformers that are in the HI4 and HI5 condition categories at the end of 2024. This is shown in the table below.

Table 18
2020-2024 Underground Transformer Replacements in the Underground Renewal - Horseshoe Program

Underground Transformers	2017[280]	2024 without investment[281]	Replacement Required to Maintain level[282]	Proposed Replacements[283]
HI4 & HI5	559	1,738	1,179	1,941

OEB staff submits that, in total, Toronto Hydro, on a planned basis, intends to replace 762 (64.6%) more underground transformers than would be required based on the HI scores determined through its ACA.

278 Exhibit 2B / Section E2 / p. 10.
279 Exhibit 2B / Section D / Appendix C / p. 11.
280 Undertaking J1.4.
281 Undertaking J1.4.
282 2024 HI4 and HI5 without investment minus 2017 HI4 and HI5; and Oral Hearing Transcripts / Vol. 3 / p. 33.
283 Exhibit 2B / Section E6.2 / p. 28.

Toronto Hydro explained that one of the main reasons for transformer replacements in excess of the amounts required to maintain the amount of transformers in the HI4 and HI5 categories is that a key driver for the program is addressing the risk that the transformers have PCBs. Toronto Hydro has certain obligations that require assets with PCBs to be pulled out of service by 2025.[284] However, Toronto Hydro acknowledges that while its ACA does not have a specific input for the presence of PCBs, older assets are both more likely to have PCBs and be in worse condition.[285] On that basis, OEB staff submits that the transformers in the HI4 and HI5 categories are very likely to already include the transformers that have PCBs. As such, the majority of the incremental 762 transformers that Toronto Hydro proposes to replace beyond those that are in the HI4 and HI5 categories reflect an overstatement of the capital needs of the utility during the 2020-2024 Custom IR term.

With respect to the replacement of underground switches in the Underground Renewal – Horseshoe program, a similar overstatement of capital needs exists. Toronto Hydro proposes to replace, on a planned basis, 231 switches over the 2020-2024 period and only 77 replacements are required to maintain the number of underground switches that are in the HI4 and HI5 condition categories at the end of 2024. This is shown in the table below.

Table 19
2020-2024 Underground Switches Replacement in the Underground Renewal - Horseshoe Program

Underground Switches	2017[286]	2024[287]	Replacement Required to Maintain[288]	Proposed Replacements[289]
HI4 & HI5	80	157	77	231

OEB staff submits that, in total, Toronto Hydro, on a planned basis, intends to replace 154 (200%) more underground switches than would be required based on the HI scores determined through its ACA.

[284] Oral Hearing Transcripts / Vol. 3 / p. 36.
[285] Oral Hearing Transcripts / Vol. 3 / p. 35.
[286] Undertaking J1.4.
[287] Undertaking J1.4.
[288] 2024 HI4 and HI5 without investment minus 2017 HI4 and HI5; and Oral Hearing Transcripts / Vol. 3 / p. 39.
[289] Exhibit 2B / Section E6.2 / p. 28.

Toronto Hydro explained that the reason for the large number of proposed replacements is that air-insulated switches fail earlier than their typical useful life and earlier than the HI scores might indicate.[290] OEB staff notes that, in its pre-filed evidence, Toronto Hydro specifically stated that the number of air-insulated switches in HI5 condition is anticipated to rise from about 40 to over 130 in 2024[291], which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field.[292] Contrary to the discussion at the oral hearing, OEB staff submits that Toronto Hydro's pre-filed evidence implies that the increase in the number of switches in HI5 condition (between 2017 and 2024) already reflects the "accelerated rate of degradation" that Toronto Hydro has experienced in the field. Therefore, the majority of the incremental 154 switches that Toronto Hydro proposes to replace beyond those that are in the HI4 and HI5 categories reflect an overstatement of the capital needs of the utility during the 2020-2024 Custom IR term.

Interaction of Planned and Reactive Capital Spending

Toronto Hydro proposed budgets for both planned (proactive) system renewal and reactive system renewal. Toronto Hydro stated that 10% to 20% of its reactive capital work requests involve an intervention on an asset that is already part of an existing planned capital scope of work. These requests result in less than $5 million in capital expenditures annually and only a fraction ($2 million of this overlap of work) result in opportunities to reduce planned capital. Toronto Hydro further stated that where opportunities exist to reduce planned capital expenditures, it has accounted for these opportunities, typically, by reducing planned volumes of work.[293]

OEB staff submits that Toronto Hydro has not adequately accounted for the amount of planned capital work that is ultimately completed on a reactive basis. As such, there is a double-counting of forecasted capital spending in the planned system renewal budget as a portion of the planned work will be completed on a reactive basis using funds that Toronto Hydro is seeking approval of as part of the reactive capital budget in the current proceeding.

OEB staff submits that the estimate that only 10% to 20% of its reactive work requests

[290] Oral Hearing Transcripts / Vol. 3 / pp. 39-40.
[291] The number of assets in HI5 condition cited here was updated in Undertaking J1.4 (143 in HI5 condition).
[292] Exhibit 2B / Section E6.2 / p. 3.
[293] Undertaking JTC 1.11.

involve an intervention on an asset that is already part of a planned scope of work is either understated or, alternatively, Toronto Hydro is not targeting its planned capital investments at assets that are in the worst condition. An estimate that only $2 million of the overlap in work results in opportunities to reduce planned capital cannot be accurate.

Toronto Hydro stated that many of the assets that it replaces reactively are old and that the assets in HI4 and HI5 condition are the higher priority items for investment with its planned system renewal budget.[294] The ACA utilizes age as an input. Therefore, it would be reasonable to expect that there would be a very considerable overlap between the assets targeted for replacement on a planned basis and the assets that are, on an actual basis, replaced reactively (unless of course, Toronto Hydro is not actually targeting its planned capital investment at the assets that are in the worst condition). For example, Toronto Hydro stated that it investigated 145 failed overhead transformers between 2013 and 2017 to identify the root causes of failure and 37% of the failures were related to assets that were past the end of their useful lives (and the number of failures increased with transformer age).[295] OEB staff submits that these overhead transformers that are past the end of their expected useful lives are the transformers that would be targeted by Toronto Hydro's planned overhead system renewal budget but, on an actual basis, could be replaced reactively if they fail prior to the planned replacement.

OEB staff recognizes that the reactive budget would also replace many assets that are not targeted for planned replacement. This could be for a number of reasons: adverse weather conditions, asset malfunction on a newer asset, etc. However, OEB staff expects that a significantly larger percentage of its planned capital work will end up being completed reactively than Toronto Hydro has estimated.

In addition, Toronto Hydro seems to imply that because it forecasts planned capital spending on historical unit costs, there would be no double counting between the planned and reactive capital budgets.[296] OEB staff submits that this is not correct. Using historical unit costs to forecast capital budgets, in the absence of actually reducing the

[294] Oral Hearing Transcripts / Vol. 1 / p. 137.
[295] Exhibit 2B / Section E6.5 / pp. 8-9.
[296] Oral Hearing Transcripts / Vol. 1 / pp. 140-141. Toronto Hydro uses its overhead renewal program as an example. However, OEB staff assumes that this logic would apply to other planned capital programs that rely on historical unit costs to forecast the 2020-2024 program budgets.

forecast number of units to be replaced, would not avoid the double counting concerns raised by OEB staff.

Toronto Hydro stated, in the context of its overhead system renewal program, that if it only replaced 97 poles instead of 100 poles, the actual historical costs used to forecast the capital budget going forward would reflect only the replacement of 97 poles.[297] It is true that the actual costs (the numerator in a unit cost calculation) would reflect the costs of only 97 poles. However, the denominator in a unit cost calculation would also be based on the actual number of poles replaced (97) (otherwise the unit cost calculation would not be accurate). Therefore, the historical unit costs applied in the calculation of the forecast overhead system renewal costs would not be lower than if all 100 poles were replaced on a planned basis (as the reactive replacements are removed from both sides of the unit cost calculation). OEB staff submits that the use of historical actuals in the unit cost calculation does not address the overlap between planned and reactive system renewal.

OEB staff submits that the only way to actually ensure that there is no double counting between the planned and reactive system renewal budgets is to manually adjust the number of planned replacements for an estimate of the number of assets that will be replaced reactively. Toronto Hydro states that it has made allowances for the fact that some of the assets targeted by its planned system renewal budget will be replaced reactively.[298] Toronto Hydro uses a number of examples that show it is going to replace less assets, in a subset of its system renewal programs, than those that are in HI4 and HI5 condition to reflect the anticipated impact of reactive capital.[299] However, the reason for the lower levels of investment are not at all tied to reactive capital in the pre-filed evidence. Those decisions are simply pacing choices that Toronto Hydro has made and reflected in its proposed capital budgets.[300] OEB staff submits that Toronto Hydro has not adequately shown that the necessary adjustments to avoid a double counting of planned and reactive capital were made.

Overall, OEB staff submits that Toronto Hydro has underestimated the amount of planned capital work that will be completed reactively on an actual basis and has not made the appropriate adjustments to its planned system renewal budget. Therefore,

[297] Oral Hearing Transcripts / Vol. 1 / pp. 140-141.
[298] Oral Hearing Transcripts / Vol. 1 / p. 145; and Undertaking JTC1.11.
[299] Undertaking JTC1.11. The programs discussed are Underground System Renewal (Horseshoe and Downtown) and Network System Renewal.
[300] Exhibit 2B / Section E6.3 / p. 3; and Exhibit 2B / Section E6.4 / p. 2.

OEB staff is of the view that Toronto Hydro's planned system renewal budget is overstated.

Planned System Renewal Reduction

As discussed, OEB staff has a number of concerns with Toronto Hydro's planned system renewal budget. OEB staff has discussed in detail the ACA methodology, the targeting of system renewal investments (in both the 2015-2019 period and in the proposed 2020-2024 Custom IR term), the overall asset management maturity, the proposed overspending in the Underground Renewal – Horseshoe program, and the double counting of planned and reactive capital. OEB staff submits that an appropriate reduction to the planned system renewal budget (excluding area conversions and reactive & corrective capital) to address these issues (and the related overstatement of the budget) is 15%. This results in a reduction of $162.3 million.[301] This reduction will result in a planned system renewal budget (excluding area conversions and reactive capital) for the 2020-2024 Custom IR term of approximately $920 million. This compares to $856.8 million of actual capital expenditures for this sub-category during the 2015-2019 period.[302] OEB staff's proposed reduced budget of $920 million reflects an increase, period-over-period, of $63.2 million (or 7.4%), which OEB staff submits is a more appropriate increase in the context of the concerns raised. OEB staff also notes that this level of increase in the capital budget is reasonably aligned with expected inflation between 2016 and 2020.[303]

Rear Lot Conversions

Toronto Hydro proposes capital expenditures of $221.3 million on area conversions during the 2020-2024 Custom IR period.[304] As part of the proposed area conversion budget, Toronto Hydro plans to invest $113.5 million to convert approximately 2,350 rear lot customers by the end of 2024. The budget for this program is based on historical unit costs of $0.036 million per customer plus inflation, engineering and support costs.[305] The main rationale for the program is that it will serve to reduce

[301] Calculated as total system renewal budget ($1,621 million) minus area conversion budget ($221.3 million) and reactive and corrective capital budget ($317.2 million) equals $1,082.3 million * 15%.
[302] Exhibit U / Tab 2 / Schedule 2 / Appendix A.
[303] Based on OEB-approved, and 2020 estimated, inflation factors, which totaled inflationary increases of approximately 8% over the noted period.
[304] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.
[305] Exhibit 2B / Section E6.1 / pp. 20-21.

outage time for approximately 2,350 customers and resolve safety concerns with respect to crew and public exposure to rear lot construction.[306]

Toronto Hydro explained that the $0.036 million historical unit cost is based on an average of three projects (Markland Woods, Thorncrest and Forest Hill) that were completed over the 2013-2017 period. Toronto Hydro noted that these were the most recently completed projects at the time of filing and therefore, provided the most accurate unit cost information.[307]

OEB staff asked Toronto Hydro to provide information for all the projects that it had completed during the 2013-2018 period. Toronto Hydro provided an update showing one additional project, which resulted in an average historical unit cost of $0.037 million.[308] However, the updated response provided (now with four projects), only reflected approximately 1,400 rear lot conversions (as opposed to the total number of conversions that occurred of 2,347).[309]

Toronto Hydro explained that it used a limited subset of the total conversions completed (i.e. the Markland Woods, Thorncrest and Forest Hill conversions) as these projects had the expenditures grouped in a manner that is appropriate to use for a unit cost calculation. Toronto Hydro further explained that rear lot conversion projects are multi-phased and in many cases, the rear lot conversions undertaken historically are not purely rear lot conversions. Instead, they are “majority rear lot” conversions as some customers in the rear lot neighbourhood may already be fed underground or front lot overhead.[310]

OEB staff submits that Toronto Hydro was not able to provide the total cost associated with converting 2,347 customers (due to deficiencies in the data). Instead, Toronto Hydro is relying on unit costs based on only a subset of the conversions completed.

OEB staff notes that during the 2015-2019 period, 2,347 rear lot conversions were completed at a total cost of $59.9 million.[311] This results in a historical unit cost for rear lot conversions of $0.0255 million.

[306] Exhibit 2B / Section E6.1 / pp. 2-3.
[307] Undertaking JTC1.8.
[308] U-Staff-173.
[309] U-Staff-173; and Oral Hearing Transcripts / Vol. 1 / p. 151.
[310] Oral Hearing Transcripts / Vol. 1 / pp. 148-149.
[311] Oral Hearing Transcripts / Vol. 1 / pp. 147-148; Exhibit 2B / Section E6.1 / p. 20; and Exhibit U / Tab 2 / Schedule 2 / p. 10.

OEB staff submits that for the historical unit costs, to convert 2,347 customers with rear lot infrastructure, to be $0.036 million, Toronto Hydro would have actually had to spend $84.5 million on these conversions (as opposed to $59.9 million). This means that Toronto Hydro would have had to spend approximately $24.6 million in the period prior to 2015 on these same conversions. OEB staff submits that this level of spending in the period prior to 2015 is very unlikely to have occurred as the average duration of a project is 13 months.[312] As such, the unit costs of $0.036 million are very likely to be overstated.

OEB staff believes that Toronto Hydro has overstated the unit costs for the rear lot conversions by only using the limited set of data where it has the expenses grouped in manner that can be used to calculate unit costs. OEB staff submits that the rear lot conversions (approximately 950 conversions), for which the costs have not been made available, have lower unit costs than those presented as part of this proceeding.

OEB staff submits that a reasonable estimate of the unit costs that should be used for the rear lot conversion forecast is $0.03 million (which reflects a reduction of $0.006 million to the proposed unit costs). OEB staff believes that some costs were likely incurred in the period prior related to rear lot conversions so it would be reasonable to use a unit cost estimate that is: (a) higher than the $0.0255 million calculated by simply dividing the 2015-2019 capital expenditures ($59.9 million) by the total number of conversions over that period (2,347); but (b) lower than the proposed $0.036 million.

OEB staff notes that the historical unit costs represent $88 million[313] of the total 2020-2024 rear lot conversion budget (with $25.5 million for inflation, engineering and support costs representing the remaining costs).[314] OEB staff submits that the base costs of $88 million (calculated using the historical unit costs) as proposed for the rear lot conversion budget should be reduced to $70.4 million (a reduction of $17.6 million from the proposed amount). OEB staff submits that the inflation and other support costs should be reduced, as appropriate, to reflect the lower base costs. OEB staff estimates that the total reduction to the rear lot conversion budget will be approximately $20 million (after adjustments are made to inflation and other support costs). OEB staff submits that the proposed reduced rear lot conversion budget should be sufficient to address reliability

[312] Exhibit 2B / Section E6.1 / p. 21.
[313] OEB staff notes that the base costs of $88 million (calculated using the historical unit costs) as proposed for the rear lot conversion budget appears to be incorrect even using the $0.036 million unit costs. Based on the proposed conversions of 2,348 and unit costs of $0.036 million, the base costs should be $84.5 million (even in the absence of any adjustment to the unit costs).
[314] 2B-Staff-80(b).

and safety concerns as the reductions are designed to ensure that a more reasonable unit cost, based on historical actuals, is used in the forecasted budget.

In addition, OEB staff submits that the amount spent on rear lot conversions is extremely high on a per customer converted basis (whether the unit costs used are as proposed by Toronto Hydro or OEB staff). The OEB should apply a downward adjustment to the pacing of the program as the cost per customer is too high and the conversions should be completed over a longer period of time.

System Service

The table below provides the proposed net capital expenditures for each program within the system service category.[315]

Table 20
2020-2024 System Service Capital Expenditures

($M)	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
Energy Storage Systems	$ 1.0	$ 3.7	$ 3.8	$ 1.0	$ 1.0	**$ 10.5**
Network Condition Monitoring and Control	$ 8.0	$ 10.2	$ 12.6	$ 15.3	$ 17.4	**$ 63.4**
Stations Expansion	$ 19.5	$ 40.0	$ 49.3	$ 12.5	$ 15.2	**$ 136.4**
System Enhancements	$ 6.2	$ 6.2	$ 5.6	$ 4.8	$ 4.9	**$ 27.7**
System Service Total	**$ 34.6**	**$ 60.1**	**$ 71.3**	**$ 33.6**	**$ 38.5**	**$ 238.1**

The system service category includes capital expenditures related to system enhancements, energy storage systems, network condition monitoring and control, and station expansions. The investments are designed to support the utility's asset management objectives and deliver customer value using technology-driven solutions.[316]

OEB staff has no specific concerns with the proposed net capital expenditure budget for the system service category. Therefore, OEB staff proposes no reductions to the

[315] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.
[316] Exhibit 2B / Section E2 / p. 37.

proposed system service budget. However, OEB staff does have concerns with the energy storage system (ESS) program.

OEB staff submits that Toronto Hydro's customer-specific ESS program is not a distribution activity. However, it appears to be allowable under the exemption established in section 71(3) of the OEB Act. Accordingly, OEB staff submits this program must be accounted for separately from distribution activities, in accordance with the OEB's *Guidelines: Regulatory and Accounting Treatments for Distributor Owned Generation Facilities* (Regulatory and Accounting Treatments for Distributor Owned Generation Facilities).[317] This argument has no impact on the level of net capital expenditures (or rate base) as the customer-specific energy storage systems are proposed to be fully contributed by the customer.

OEB staff also submits that the installation and operation of EV charging infrastructure (for which Toronto Hydro has no proposals, but was raised in the evidence of the Distributed Resource Coalition (DRC)) is also a non-distribution activity.

Energy Storage Systems

Toronto Hydro proposed capital expenditures in three distinct segments for the ESS program:

- Grid Performance ESS would use batteries to remediate power quality problems, improve reliability, and increase feeder capacity at peak periods.[318]

- Renewable Enabling ESS would use batteries to absorb excess energy from renewable generators to maintain an appropriate generation to load ratio on a feeder.[319]

- Customer-Specific ESS would use a battery installed behind a customer's meter, at the customer's request, to provide improved power quality and reliability, as well as financial benefits from peak-shaving and Global Adjustment relief for Class A customers through the Industrial Conservation Initiative.[320]

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[317] OEB Guidelines: Regulatory and Accounting Treatment for Distributor-Owned Generation Facilities / September 15, 2009.
[318] Exhibit 2B / Section E7.2 / p. 2.
[319] Exhibit 2B / Section E7.2 / p. 21.
[320] Exhibit 2B / Section E7.2 / p. 4.

The gross costs of the program and Toronto Hydro's proposed mechanisms for recovery of the costs are set out in the table below.[321]

Table 21
Energy Storage System Capital Expenditures by Category

ESS Segment	**Rate Base** (A)	**Provincial Benefit** (B)	**Net Costs** (C = A + B)	**Capital Contribution** (D)	**Gross Costs** (D + C)
Grid Performance	$5.5	$0	$5.5	$0	**$5.5**
Renewable Enabling	$0.3	$4.7	$5.0	$0	**$5.0**
Customer Specific	$0	$0	$0	$42.3	**$42.3**
Total	**$5.8**	**$4.7**	**$10.5**	**$42.3**	**$52.8**

The cost of grid performance ESS is to be recovered entirely through rate base; the cost of renewable enabling ESS is to be largely recovered through the Provincial Rate Protection program (94%); the cost of the customer-specific ESS is to be entirely recovered through capital contributions (with no impact on rate base).[322]

Grid Performance ESS and Renewable Enabling ESS

OEB staff submits that using storage as an alternative to conventional assets to provide distribution service, where it is the lower cost solution over the long term, is consistent with general expectations articulated by the OEB.[323] In OEB staff's view, Toronto Hydro's grid enhancement and renewable enabling ESS projects are, conceptually, reasonable applications of storage for the distribution system and OEB staff supports cost recovery. However, the merits of a given investment still depend on the circumstances and OEB staff is of the view that Toronto Hydro has not performed an adequate analysis to determine whether and in which instances storage is likely to be more cost-effective than alternatives.

[321] 2B-Staff-87(c). The total net costs were corrected to $10.5 million (from $10.8 million as shown in 2B-Staff-87(c)) as this reflects the information provided in Exhibit U / Tab 2 / Schedule 2 / Appendix A and properly sums to the rest of the table.
[322] 2B-Staff-87(c).
[323] OEB Handbook for Utility Rate Applications / p. 13.

For both grid performance and renewable enabling ESS projects, Toronto Hydro describes how storage can directly address the identified system needs[324] and only proposes to use storage in a subset of instances where a need was identified.[325] Toronto Hydro thus appears to have considered whether storage or a conventional solution makes sense on a case-by-case basis.

For rationale, Toronto Hydro also seems to rely on "the general benefit of deferring investment in generation, transmission, and distribution infrastructure" and "a future opportunity for demand response and grid capacity relief, thereby avoiding and/or deferring the need for distribution infrastructure investment" to make the business case for these projects.[326] However, Toronto Hydro was unable to provide any estimate of the value of deferred distribution infrastructure associated with these projects.[327] The theoretical possibility of benefits does not guarantee they will materialize and, when comparing investment options, the magnitude of benefits expected to be realized matters.

OEB staff recognizes using storage as a distribution asset is a relatively new activity and some of the costs and benefits may be difficult to estimate in the absence of practical experience. Accordingly, OEB staff does not oppose the grid performance and renewable enabling ESS projects proposed for the 2020-2024 Custom IR term as they are conceptually reasonable applications of storage for the distribution system and using storage as a distribution asset is a relatively new activity. However, in future rate applications, OEB staff submits that proposals for storage projects should be supported by a more rigorous cost-benefit assessment, including some estimation or quantification of the value of deferring other distribution system investment where applicable.

Note that further discussion of the treatment of renewable enabling ESS is discussed in section 5.3.

Customer-Specific ESS

OEB staff submits that Toronto Hydro's customer-specific ESS program is not a distribution activity. However, it appears to be permitted under the exemption

[324] Toronto Hydro described how storage can enhance grid performance by mitigating voltage sags and fluctuations and phase balancing (Exhibit 2B / Section E7.2 / p. 3) and how storage can be deployed on such feeders in order to lower the generation to minimum load ratio (Exhibit 2B / Section E7.2 / p. 21).
[325] Exhibit 2B / Section E7.2 / p. 3 and Exhibit 2B / Section E7.2 / p. 25.
[326] 2B-Staff-88(a) / p. 2-3; and Exhibit 2B / Section E7.2 / p. 17.
[327] 2B-Staff-88(b) and 2B-Staff-88(c) / p. 3.

established in section 71(3) of the OEB Act. Accordingly, OEB staff submits this program must be accounted for separately from distribution activities, in accordance with the OEB's Regulatory and Accounting Treatments for Distributor Owned Generation Facilities.[328] In addition, Toronto Hydro's customer-specific ESS program raises policy concerns that OEB staff believes should be considered in the OEB's Responding to DERs consultation.

Customer-Specific ESS is Not a Distribution Activity

Toronto Hydro appears to take the position that customer-specific ESS is a distribution activity.[329] OEB staff disagrees. In OEB staff's view, this is not a distribution activity for two reasons. First, the storage systems do not meet criteria previously established by the OEB for categorizing distribution system assets.[330] Second, the services Toronto Hydro proposes to provide – back up power in case the distribution system fails and financial benefits to the customer[331] – are not ones that distributors are required, or generally ought, to deliver.

In developing its view that the proposed storage systems are not distribution assets, OEB staff considered the OEB's determinations in its decision on whether street light assets should be considered part of the distribution system (street light decision).[332] In that decision, the OEB found "an essential feature of a distribution asset is that the asset must be used to convey electricity and that the concept of distribution implies "multiple recipients". In the same decision, the OEB applied the "Intended Use Test" (i.e. what is the primary purpose of the asset, as opposed to its use at any given point in time) to determine whether an asset is part of the distribution system.[333]

Toronto Hydro's evidence indicates these storage assets are not intended to convey electricity (or facilitate the conveyance) of electricity to multiple recipients. Toronto Hydro states ". . . each project is expected to predominantly benefit a single customer."[334] OEB staff notes that while there are distribution assets, such as meters or

[328] OEB Guidelines: Regulatory and Accounting Treatment for Distributor-Owned Generation Facilities / September 15, 2009.
[329] Exhibit 2A / Tab 4 / Schedule 1 / p. 2; and 2B-Staff-90(b) / p. 3.
[330] EB-2009-0180 / 0181 / 0182 / 0183 / Decision and Order / February 11, 2010.
[331] Exhibit 2B / Section E7.2 / p. 4.
[332] EB-2009-0180 / 0181 / 0182 / 0183 / Decision and Order / February 11, 2010.
[333] EB-2009-0180 / 0181 / 0182 / 0183 / Decision and Order / August 3, 2011 / p. 3.
[334] Exhibit 2B / Section E7.2 / p. 30.

service connections, that serve single customers; these assets, unlike the proposed customer-specific storage assets, are fundamental to basic distribution service.

Toronto Hydro indicated that benefits to the distribution system are possible because of these customer-specific storage projects.[335] However, OEB staff notes that Toronto Hydro was unable to demonstrate any quantifiable benefits to the distribution system, or to customers other than the host customer.[336] In fact, Toronto Hydro's proposed cost allocation approach suggests there are no system benefits of this project: "[i]n accordance with the beneficiary pays principle, these costs are presumptively fully allocated to the customer who benefits."[337] Toronto Hydro's evidence in this regard does not support the argument that this is a distribution activity.

Despite this allocation of costs, Toronto Hydro nevertheless maintains that system benefits could be delivered by this storage system in certain circumstances. It states potential system benefits would take precedence in the event of a conflict between the desires of the host customer and benefits to the distribution system; this arrangement would reportedly be reflected in an operational agreement between Toronto Hydro and the customer that has yet to be developed.[338] OEB staff notes the realization of potential system benefits depends upon the host customer signing an agreement that allows Toronto Hydro to repurpose the battery that the customer has paid for (for reasons that go beyond maintaining safety and reliability), even though this can result in the customer missing out on financial benefits the battery would otherwise provide.

In OEB staff's view, the primary intended use of the asset is for a single customer's benefit, not to facilitate the distribution of electricity to many customers. Any benefits to the system are theoretical at this point and, if they do materialize, may be minimal. In addition, placing an energy storage system behind the meter and classifying it as a distribution asset is inconsistent with what the OEB has previously described as "well established ownership demarcation points" separating the distribution system and customer assets.[339]

The Distribution System Code (DSC) defines "distribution services" as "services related to the distribution of electricity and the services the Board has required distributors to

[335] Oral Hearing Transcript / Vol. 1 / p. 169-171 and 2B-Staff-88(a) / p. 2-3.
[336] Oral Hearing Transcript / Vol. 1 / p. 171.
[337] Exhibit 2B / Section E7.2 / p. 31.
[338] Oral Hearing Transcript / Vol. 1 / p. 172-175.
[339] EB-2009-0180, 0181, 0182, 0183 / Decision and Order / February 11, 2010 / p. 6

carry out."[340] In OEB staff's view, emergency back-up service to protect against interruptions, financial benefits through peak shaving and Global Adjustment relief for Class A customers[341] do not fall within the definition of distribution services.

Customer-Specific ESS Program Appears to be Allowed Under Section 71(3) of the OEB Act and Must Be Accounted for Separately

Section 71(3)(c) of the OEB Act states a distributor may own and operate an energy storage facility that meets any criteria prescribed by regulation. No criteria has been prescribed at this time. It appears that Toronto Hydro's customer-specific ESS program is a non-distribution activity in which distributors are allowed to engage under this sub-section of the legislation.

OEB staff notes section 72 of the OEB Act states "(e)very distributor shall keep its financial records associated with distributing electricity separate from its financial records associated with other activities." In a compliance bulletin, OEB staff confirmed "the ownership and operation of qualifying facilities is not currently a rate-regulated activity under section 78(3) of the OEB Act. Qualifying facilities are not included in rate base and any costs in respect of such facilities are not recovered through rates."[342] The OEB has provided direction to distributors on financial separation of these types of activities from distribution activities in the OEB's Regulatory and Accounting Treatments for Distributor Owned Generation Facilities.[343] OEB staff submits that Toronto Hydro should adhere to this guideline in carrying out its customer-specific ESS program.

This approach would avoid any capital or OM&A cost overruns associated with these projects being borne by ratepayers, rather than the host customer receiving the service, which Toronto Hydro conceded would be a consequence of its proposed approach.[344] OEB staff also notes that, should Toronto Hydro's proposal to include the storage asset in rate base (even at a net zero dollar value) be accepted, a potential outcome is that the cost of its replacement would be recovered through Toronto Hydro's rates, in accordance with section 3.1.7 of the Distribution System Code, despite the facility having originally been fully paid for via a customer's capital contribution. OEB staff is of

340 OEB Distribution System Code / p. 10.
341 Exhibit 2B / Section E7.2 / p. 4.
342 Compliance Bulletin / Distributor-Owned Generation: Application of Section 71(3) of the *Ontario Energy Board Act,* 1998 / July 7, 2010
343 OEB Guidelines: Regulatory and Accounting Treatment for Distributor-Owned Generation Facilities / September 15, 2009.
344 Oral Hearing Transcripts / Vol. 1 / p. 132.

the view that it is unacceptable for Toronto Hydro's ratepayers to be at risk for any costs associated with a non-distribution activity.

In addition, OEB staff notes, in its determination on Enbridge Gas Distribution Inc.'s Renewable Natural Gas proposal, the OEB found:

> "Even if RNG Upgrading had been found to be a distribution activity, the OEB concludes that it is not appropriate for the RNG Upgrading Service to be a rate-regulated activity for two reasons. First, RNG Upgrading Service is potentially a competitive activity in Ontario. Enbridge itself acknowledges that the RNG Upgrading Service can also be done by RNG producers. This is the reason that Enbridge has proposed this to be an optional service. Enbridge has argued that there is "no evidence of any current market players who will be adversely impacted by EGD offering a regulated RNG Upgrading service". The OEB notes that the effect on competitors is only one consideration. Second, the OEB must also consider whether natural gas customers should bear any risk for this competitive service. The OEB finds that they should not."[345]

OEB staff is of the view that Toronto Hydro's customer-specific ESS proposal is not a distribution activity. However, should the OEB disagree with OEB staff on that point, OEB staff submits it should still not be rate-regulated and Toronto Hydro should still be required to account for this activity separately.

Customer Specific ESS Proposal Raises Policy Issues

Although OEB staff accepts that Toronto Hydro's customer-specific ESS program appears to be allowed under the current legislative framework, OEB staff nevertheless has concerns about this proposal from a policy perspective.

If the program is not accounted for separately from distribution activities as OEB staff has submitted it should be, OEB staff is concerned it will impose unjustified risk on Toronto Hydro's customer base (while offering minimal, if any, benefits). While OEB staff grants this activity appears to be permitted under the OEB Act, it is nevertheless concerned about the potential impacts of a regulated-monopoly participating in an emerging competitive market for storage services. One source of this concern is that first-mover and other market advantages, such as those which stem from pre-existing

[345] EB-2017-0319 / Decision and Order / October 18, 2018 / p. 11.

services relationships, which distributors may already enjoy, may not be fully understood.

The OEB has launched a policy consultation to consider how to integrate DERs, such as storage. OEB staff anticipates that matters such as which entities should engage in different DER-related activities, and how to maintain an appropriate separation between distribution and other activities as the sector evolves, among others, will be considered.

Distributed Resource Coalition's Evidence

OEB staff notes that the evidence filed by DRC has raised issues in relation to Toronto Hydro's role in supporting the electrification of transportation in the City of Toronto.[346] OEB staff is unsure whether DRC is proposing that Toronto Hydro own and operate behind the meter EV charging stations.[347] If that is DRC's position, OEB staff submits that owning and operating EV charging stations and providing EV charging services is also a non-distribution activity. This is consistent with the July 7, 2016 OEB Staff Bulletin which sets out OEB staff's view that "the ownership or operation of an EV charging station, and the selling of EV charging services from that facility, do not constitute distribution or retailing."[348]

More generally, OEB staff notes that the DRC evidence shows that there may be some electrification of transit in Toronto Hydro's service territory (with related load growth) over the 2020-2024 period.[349] OEB staff accepts Toronto Hydro's explanation that, based on what is currently known and factored into its capital plan, any such load can be accommodated (as Toronto Hydro does not expect the load growth to materially impact its system plan).[350]

<u>General Plant</u>

The table below provides the proposed capital expenditures for each program within the general plant category.[351]

[346] Exhibit M2 / CUTRIC Report.
[347] Exhibit M2-Staff-1 / p. 3.
[348] OEB Staff Bulletin on Electric Vehicle Charging / July 7, 2016 / p. 2.
[349] Exhibit M2 / CUTRIC Report / p. 5.
[350] Oral Hearing Transcripts / Vol. 4 / p. 19.
[351] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.

Table 22
2020-2024 General Plant Capital Expenditures

($M)	2020	2021	2022	2023	2024	Total
Facilities Management and Security	$ 11.6	$ 11.8	$ 12.1	$ 12.3	$ 12.6	**$ 60.4**
Fleet and Equipment	$ 8.6	$ 8.9	$ 8.5	$ 8.7	$ 7.8	**$ 42.4**
IT/OT Systems	$ 55.6	$ 55.7	$ 49.5	$ 56.6	$ 64.8	**$ 282.2**
Control Operations Reinforcement	$ 3.9	$ 17.4	$ 18.9	-	-	**$ 40.2**
General Plant Total	**$ 79.6**	**$ 93.7**	**$ 89.0**	**$ 77.7**	**$ 85.2**	**$ 425.2**

The general plant category includes capital expenditures related to facilities management and security, fleet and equipment, Information Technology (IT) / Operational Technology (OT) systems, and control operations reinforcement. The investments in this category are designed to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs and emerging customer needs.[352]

OEB staff submits that reductions to general plant capital expenditure budget are appropriate. Specifically, OEB staff submits that the control operations reinforcement program does not seem to be required at this time ($40.2 million reduction) and a 10% reduction to the fleet and equipment budget ($4.2 million reduction) is appropriate.

In addition, OEB staff submits that the forecast cost savings (which were not fully achieved) related to the Enterprise Resource Planning (ERP) project completed during the 2015-2019 period should be included as a reduction to the OM&A budget.

Control Operations Reinforcement

Toronto Hydro proposed to construct a fully functional control centre, which will operate and control Toronto Hydro's distribution grid in parallel with the primary control centre (the dual control centre).[353] The proposed dual control centre will replace Toronto

[352] Exhibit 2B / Section E2 / p. 40.
[353] Exhibit 2B / Section E8.1 / p. 1; and 2B-Staff-96.

Hydro's existing back-up control centre.[354] The cost of project is forecast to be $40.2 million and the dual control centre is forecast to come into service in 2022.[355]

There are incremental OM&A costs associated with the project of $0.35 million per year for facilities related costs and IT costs. There are no incremental full-time equivalents (FTEs) or related compensation costs as a result of the parallel control centre.[356]

The rationale for the proposed dual control centre is to increase Toronto Hydro's operational resiliency and improve the utility's ability to safely operate the distribution grid. The dual control centre will be designed to withstand evolving hazards and threats, deliver reliable electricity, and support the capability to restore electricity as efficiently as possible.[357] Toronto Hydro discussed the need for the dual control centre in the context of potential threats to its ability to operate its system if its primary control centre were compromised. Toronto Hydro, specifically, raised potential hazards linked to extreme weather events, terrorism, and cyber attacks. Toronto Hydro also noted that the growth of distributed generation has given distributors some of the reliability responsibilities traditionally reserved for transmission utilities.[358]

Toronto Hydro filed a report by London Economics International (LEI), which undertook a review of comparator utilities to assess Toronto Hydro's proposed investment in a dual control centre.[359]

LEI's methodology for identifying comparator utilities was to review the twenty largest US utilities and five largest Canadian distributors by number of customers.[360] Of the 25 utilities surveyed, LEI found that only five had dual control centres.[361] In addition, of the five that had dual control centres, three of them serve both transmission and distribution functions.[362] OEB staff also notes that all of the utilities that have dual control centres

[354] Exhibit 2B / Section E8.1 / p. 1.
[355] 2B-Staff-96 (d).
[356] 2B-Staff-96 (f).
[357] Exhibit 2B / Section E8.1 / p. 1.
[358] Exhibit 2B / Section E8.1 / pp. 2-3.
[359] Exhibit 2B / Section E8.1 / p. 3.
[360] Oral Hearing Transcripts / Vol. 5 / p. 79.
[361] Oral Hearing Transcripts / Vol. 5 / p. 80; and Exhibit 2B / Section E8.1 / Appendix A / p. 4.
[362] Oral Hearing Transcripts / Vol. 5 / pp. 80-82.

have larger customer counts, delivered electricity amounts[363], and service areas than Toronto Hydro.[364]

OEB staff submits that Toronto Hydro has discussed valid benefits of a dual control centre. There would likely be benefits to the system of a dual control centre in the scenario where the primary control centre is compromised for any reason. However, based on the LEI study, 20 (out of 25) of the largest utilities in Canada and the US operate in the absence of a dual control centre. The costs of the project are significant ($40.2 million) and OEB staff does not believe that the dual control centre is required at this time as many of the largest utilities operate in the absence of a dual control centre. As such, OEB staff submits that the OEB should disallow $40.2 million of capital expenditures that are included in the general plant budget related to this project.

OEB staff suggests that Toronto Hydro complete another jurisdictional review, in advance of its next rebasing proceeding, to determine whether there has been a large movement towards a dual control centre model and this request can be revisited at that time.

Fleet and Equipment Services

Toronto Hydro's proposed 2020-2024 fleet and equipment services budget is $42.5 million. The fleet and equipment services program is responsible for the procurement, maintenance, and disposal of vehicles and equipment that are needed to support Toronto Hydro's functional and operation needs.[365] The majority of the budget is related to the replacement of heavy duty and light duty vehicles.[366]

Toronto Hydro provided its fleet utilization percentages as follows:

- 2015 Actual – 52%
- 2016 Actual – 49%
- 2017 Actual – 45%
- 2018 Bridge – 44%
- 2019 Bridge – 47%

[363] One utility has lower delivered electricity amounts than Toronto Hydro.
[364] Exhibit 2B / Section E8.1 / Appendix A / p. 8. With respect to the two utilities that serve only distribution functions, these differences in customer count and delivered electricity is particularly apparent.
[365] Exhibit 2B / Section E8.3 / p. 1.
[366] Exhibit 2B / Section E8.3 / p. 8.

- 2020 Forecast – 50%[367]

Toronto Hydro's fleet utilization is tracked in terms of "standard working hours" defined as the total hours that the vehicle is outside its home zone[368] during standard hours divided by the total number of standard hours per work day (7:30 am to 3:30 pm weekdays).[369]

Toronto Hydro stated that it believes that its vehicles utilization percentages are reasonable. However, it had not undertaken any benchmarking with respect to its fleet utilization relative to its own contractors or other utilities.[370]

OEB staff submits that Toronto Hydro's forecast utilization rate of 50% for 2020 is low. Toronto Hydro's vehicles being in their home zone for half of a standard work day, does not reflect optimal utilization of its assets. If Toronto Hydro were to increase its utilization rate it would be able to manage with fewer vehicles over time. As such, OEB staff submits that a 10% reduction ($4.2 million) to the fleet and equipment services budget is appropriate. This will require Toronto Hydro to more effectively utilize a smaller number of vehicles.

Information Technology and Operational Technology

Toronto Hydro's proposed 2020-2024 IT / OT budget is $282.2 million.[371] OEB staff has no specific concerns with the forecasted budget.

However, OEB staff notes that Toronto Hydro's 2015-2019 ERP project experienced cost overruns relative to the forecasted amount of $8 million ($51.3 million forecast compared to $59.3 million actual).[372] The cost savings originally forecast for 2020 related to the ERP were $4.1 million.[373] However, the revised forecast cost savings related to the project are now $1.6 million.[374] OEB staff submits that ratepayers are

[367] 4A-AMPCO-94 (b).
[368] Technical Conference Transcripts / Vol. 5 / p. 138. The home zone is essentially the garage, or work centre, to which the vehicle is assigned. OEB staff notes that while some limited productive work may occur in the home zone, when a vehicle is in its home zone, it is not at, or on its way to, the job site.
[369] 4A-AMPCO-94 (b).
[370] Oral Hearing Transcripts / Vol. 6 / pp. 9-10.
[371] Exhibit U / Tab 2 / Schedule 2 / Appendix A updated for U-Staff-168 / Table 2.
[372] U-Staff-166.3 / Appendix A; and Oral Hearing Transcripts / Vol. 5 / p. 113.
[373] Undertaking JTC3.4 / Table 1.
[374] Undertaking JTC3.4 / Table 2. The same cost savings of $1.6 million for 2020 are shown in the update to Table 2 in Undertaking J5.8.

being asked to pay for the entire cost of the ERP project (including the $8 million in cost overruns) and Toronto Hydro should be held to the benefits as originally forecast. As such, OEB staff submits that a $2.5 million reduction should be made to the OM&A budget in order to hold Toronto Hydro to its original ERP-related cost saving forecast. This is discussed in more detail in section 7.1.

OEB staff also notes that Toronto Hydro is proposing continued work on the ERP project ($46.3 million)[375] and its Customer Information System (CIS) ($38.5 million)[376] during the 2020-2024 period. For both of these projects, there are expected to be some capital and OM&A benefits. However, those benefits have not been quantified.[377]

The capital spending on the 2020-2024 aspects of the ERP and CIS projects are being sought for recovery from ratepayers. However, none of the cost savings (or in other words, expected productivity) have been passed onto ratepayers. OEB staff submits that this is one example, among many, that supports its argument for a higher base stretch factor and incremental stretch factor on capital as discussed in section 4.1 in order to require Toronto Hydro to find cost savings over the 2020-2024 Custom IR term.

Capital Expenditures - Other Category

Toronto Hydro's proposed amounts included in the other category of capital expenditures are shown in the table below.[378]

Table 23
2020-2024 Capital Expenditures – Other Category

($M)	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
AFUDC	$ 6.0	$ 8.2	$ 8.7	$ 8.9	$ 7.7	**$ 39.5**
Miscellaneous	$ 1.0	$ 0.8	$ 1.2	$ 0.6	$ 1.0	**$ 4.6**
Other Total	**$ 7.0**	**$ 9.0**	**$ 9.8**	**$ 9.5**	**$ 8.7**	**$ 44.1**

The vast majority of the other category is comprised of AFUDC. OEB staff submits that the AFUDC has not been calculated correctly and should be reduced by $5.4 million.

[375] Exhibit 2B / Section E8.4 / p. 18.
[376] Exhibit 2B / Section E8.4 / p. 18.
[377] Oral Hearing Transcripts / Vol. 5 / pp. 118-119, 123-125.
[378] Exhibit U / Tab 2 / Schedule 2 / Appendix A.

Allowance for Funds used during Construction

The total proposed AFUDC for the 2020-2024 period is $39.5 million.[379] Toronto Hydro applied a 4.2% debt rate in its calculation of AFUDC for the 2020-2024 period.[380] Toronto Hydro stated, in response to undertaking J2.1, that it has revised its proposal and that the AFUDC should be calculated using its weighted-average debt rate of 3.64%.

OEB staff agrees that the lower debt rate of 3.64%, which reflects the weighted-average cost of debt, should be used in the calculation of its AFUDC. OEB staff notes that this will reduce the AFUDC amounts by $5.4 million over the 2020-2024 period.[381]

In-Service Additions

Toronto Hydro's proposed in-service additions associated with its proposed capital expenditures (and CWIP) amount to $2,776.4 million for the 2020-2024 period.[382]

Impact of Capital Expenditure Reductions on In-Service Additions

OEB staff submits that its proposed reductions to the capital expenditures will result in reductions to the proposed in-service addition amounts (and therefore, reductions to rate base).

OEB staff notes that there is expected to be a cumulative impact on the 2020-2024 capital-related revenue requirement related to the reductions to in-service additions. For example, a reduction to in-service additions in 2020 will reduce 2020 rate base and also rate base over the 2021-2024 period. Therefore, the capital-related revenue requirement in each year 2020-2024 will be lower due to a reduction to in-service additions (and therefore rate base) in 2020.

OEB staff submits that Toronto Hydro should be required to file detailed schedules as part of its draft rate order showing how any capital expenditure reductions approved by the OEB have been translated into in-service addition reductions (and furthermore, into

[379] Exhibit U / Tab 2 / Schedule 2 / Appendix A.
[380] 2A-Staff-55(b).
[381] 2A-Staff-55 / Table 1 (Average Monthly Eligible CWIP * 3.64%).
[382] Undertaking J1.7.

reductions to rate base and capital-related revenue requirement, which is an input in the CPCI calculation, for the 2020-2024 period).

Methodology for Calculating In-Service Additions

OEB staff accepts Toronto Hydro's methodology for calculating in-service additions as part of the current proceeding. Toronto Hydro's existing methodology for calculating in-service additions is discussed below. However, OEB staff believes that Toronto Hydro should revise its approach to forecasting in-service additions for its next rebasing proceeding.

Toronto Hydro converts capital expenditures and opening CWIP to in-service additions for all distribution capital programs[383], with the exception of major discrete projects (e.g. Copeland) and general plant[384], at an aggregate level (using a generic conversion ratio) based on historical information.[385]

OEB staff has a few concerns with respect to the conversion methodology applied to distribution capital programs.

Relying on historic aggregate information (i.e. the historic conversion of aggregate distribution capital investments to in-service additions) to determine the conversion ratio would only result in accurate forecasts if the levels of spending between programs do not change over time. This is not a reasonable assumption. As the needs and priorities of the utility changes so will the relative level of spending on different programs. Different programs have varying lags between the start of construction and the in-service date. Therefore, as the level of investment in different programs changes over time, relying on a conversion ratio that is calculated based on historical information at the aggregate (as opposed to the program level) will result in inaccurate forecasts of in-service additions.

In addition, OEB staff submits that Toronto Hydro's in-service addition conversion methodology does not allow it to present a forecast of in-service additions at the program level in an accurate manner. As part of the current proceeding, Toronto Hydro provided a program-level table showing its forecast in-service additions. However,

[383] Defined as all system access, system renewal and system service investment categories.
[384] For major discrete projects and general plant, Toronto Hydro uses specific information about those investments to forecast in-service additions.
[385] Undertaking JTC1.4.

Toronto Hydro listed a number of limitations with respect to the accuracy of the forecast of program-level in-service additions.[386] Toronto Hydro stated that the OEB should not use the forecast of in-service additions at the program level provided in this proceeding, in response to Undertaking JTC3.1, due to the noted limitations to evaluate, at the next rebasing, whether Toronto Hydro had actually brought into service the assets for which it is seeking approval as part of the current proceeding.[387] As such, due to Toronto Hydro's in-service addition forecasting methodology, there is no evidence upon which to conduct a review, in a future proceeding, as to whether Toronto Hydro actually brought into service the assets that is seeking approval of as part of the current proceeding.

Finally, OEB staff submits that the result of Toronto Hydro's in-service addition conversion methodology (including its more granular approach to forecasting major capital projects and general plant) is to forecast significantly more assets coming into service (as a percentage of capital expenditures and opening CWIP) in 2020-2024 than have actually come into service historically. The actual average ratio for capital expenditures and opening CWIP conversion to in-service additions over the 2015-2018 period was 51.3% and the forecasted average for the 2020-2024 period is 56.6%.[388] OEB staff is concerned that this is not an accurate forecast based on the historical actuals.

While OEB staff has concerns with Toronto Hydro's in-service addition forecasting methodology, OEB staff submits that the proposed CRRRVA will capture variances in the quantum and timing of actual in-service addition timing relative to forecast. If the actual capital-related revenue requirement (related to in-service additions) is lower than forecast, the variance will be returned to ratepayers. If the actual capital-related revenue requirement is higher than forecast, Toronto Hydro will not be allowed to recover the incremental amounts (as the CRRRVA is asymmetrical). OEB staff is of the view that the protection provided by the CRRRVA is sufficient to satisfy its concerns with respect to the in-service addition forecasting methodology used in the current application.

However, for the next cost-based application, Toronto Hydro should revise its approach to forecasting in-service additions. For the distribution capital programs, Toronto Hydro should track the conversions at the program level during the 2020-2024 period. At the next rebasing, Toronto Hydro should forecast its in-service additions at the program level using the data it collected over the 2020-2024 period. Toronto Hydro should

[386] Undertaking JTC3.1.
[387] Oral Hearing Transcripts / Vol. 1 / pp. 189-190.
[388] Undertaking J1.11.

maintain its granular approach for forecasting in-service additions related to major capital projects and general plant. This proposed updated methodology will allow for a more accurate forecast of in-service additions. It will also provide the benefit of allowing the OEB to asses whether the assets it approves to go into service actually do go into service (at the program level).

5.3 Is the proposed treatment of renewable enabling improvement (REI) investments appropriate (Issue 3.3)?

Toronto Hydro proposed that $18.6 million of its capital expenditures be treated as REI investments. The proposed investment falls in the generation protection, monitoring & control and energy storage systems capital programs.[389]

Toronto Hydro applied the generic 6% direct benefit assumption provided in the Chapter 2 Filing Requirements.[390] On that basis, $1.1 million of the REI costs will be funded through Toronto Hydro's rate base and the remainder ($17.5 million) will be recovered through the Provincial Rate Protection program.[391]

OEB staff submits that the projects for which Toronto Hydro is seeking this treatment are appropriately considered REI projects and the proposed rate treatment of the projects is in accordance with the OEB's generic policy.[392] Therefore, OEB staff accepts Toronto Hydro's proposed treatment of these projects.

With respect to the renewable enabling ESS projects, OEB staff submits that Toronto Hydro's proposal to use storage as a renewable enabling improvement is consistent with section 3.3.2 (h) of the DSC since deploying storage on the distribution system can help accommodate 2-way electrical flows or reverse flows by absorbing excess energy.[393] The current proposal to use storage as a renewable enabling improvement is also, essentially, a continuation of what was approved in Toronto Hydro's 2015-2019 Custom IR application.[394] Therefore, OEB staff accepts Toronto Hydro's proposal for

[389] Exhibit J4.9. $13.6 million is related to the generation protection, monitoring & control program. $5 million is related to the energy storage systems program.
[390] OEB Chapter 2 Filing Requirements for Cost of Service, July 12, 2018, p. 21.
[391] Argument-in-Chief / p. 46.
[392] OEB Chapter 2 Filing Requirements for Cost of Service, July 12, 2018, p. 21.
[393] OEB Distribution System Code / p. 70.
[394] EB-2014-0116 / Decision and Order / December 29, 2015 / pp. 32-33. The OEB accepted Toronto Hydro's cost recovery breakdown related to renewable enabling improvement investments. For details of the previous proposal see Exhibit 2A / Tab 8 / Schedule 1 / pp. 3-4 and Exhibit 2B / Section E7.11 in EB-2014-0116. This is also discussed in the current application in Exhibit 2B / section E7.2 / pp. 23-25.

recovering the costs of its renewable enabling ESS investment through the Provincial Rate Protection program.

However, as discussed previously, Toronto Hydro indicated storage may provide additional benefits to the distribution system[395] but has not quantified them.[396] If those additional benefits to the distribution system prove to be material, it may be appropriate to recover a larger proportion of the costs of renewable enabling ESS from Toronto Hydro's customers (and to recover less from provincial ratepayers). Consistent with OEB staff's discussion in section 5.2, and the OEB's filing requirements, going forward Toronto Hydro should also provide a more robust cost benefit assessment to support its storage proposals, and should provide a direct benefits analysis to support any future renewable enabling ESS proposals. [397]

6. Load and Other Revenue Forecast (Issue 4.0)

6.1 Is Toronto Hydro's 2020-2024 load forecast reasonable (Issue 4.1)?

Toronto Hydro's proposed load forecast was updated in Exhibit U / Tab 3 / Schedule 1. OEB staff submits that Toronto Hydro's load forecasting methodology and the resulting updated load forecast are reasonable.[398] OEB staff notes that the load forecast will form the basis for setting 2020 base rates and to determine the growth factor in the proposed CPCI for the 2021-2024 term.

Toronto Hydro stated that its, "load and customer forecast methodologies are unchanged from those approved by the OEB in the utility's 2015-2019 Rate Application. [EB-2014-0116, footnote omitted] Forecasting models have been updated to reflect the most recently available information."[399] OEB staff notes that this is true in terms of the general methodology. However, the specific development and estimation of the load forecasting models is more variable (i.e. the models and variables are different relative to prior cases), and Toronto Hydro's documentation did not fully explain the approach. This lead to a number of interrogatories and technical conference questions, by both

[395] 2B-Staff-88(a) / pp. 2-3; and Exhibit 2B / Section E7.2 / p. 17.
[396] 2B-Staff-88(b); and 2B-Staff-88(c) / p. 3.
[397] OEB Chapter 2 Filing Requirements for Cost of Service, July 12, 2018, p. 21.
[398] Exhibit 3 / Tab 1 / Schedule 1; and Exhibit U / Tab 3 / Schedule 1.
[399] Exhibit 3 / Tab 1 / Schedule 1 / p. 3.

OEB staff and other parties, on changes in the model specifications, and on what variables and statistical tests Toronto Hydro relies in estimating the models.[400]

Toronto Hydro does its load forecasting internally, unlike many other utilities.[401] OEB staff takes no issue with this and recognizes that Toronto Hydro does have the necessary resources and expertise. However, there is a benefit to testing established methods for purposes of continuous improvement by exposing the details of the methodology to the informed judgement, experience and expertise of others. OEB staff notes that there is not a simple menu for conducting these econometric analyses. However, it is the load – customers, consumption and demand which drive the capital and operating costs incurred by the utility to serve the load, and which the utility seeks to recover through rates. OEB staff submits that Toronto Hydro should better document its load forecasting methodology in future proceedings.

Conservation and Demand Management Adjustment

OEB staff notes that Toronto Hydro's load forecast explicitly accounts for the Conservation and Demand Management (CDM) impact on load. However, the load forecast was prepared prior to the recent government announcements with respect to the discontinuation of certain CDM programs in the province. Toronto Hydro noted that, based on its high-level analysis, removing the CDM programs that are expected to be cancelled from the load forecast will have an immaterial impact.[402] OEB staff accepts that adjustments to the load forecast for the noted CDM programs would be immaterial and therefore submits that no changes are warranted.

OEB staff also notes that the LRAMVA will continue to operate during the 2020-2024 Custom IR term. As such, any variances between the CDM adjustments included in the load forecast and the actual CDM that occurs will be trued-up through the LRAMVA.

[400] 3-Staff-101 to 3-Staff-106; 3-CCC-32; 3-CCC-33; 3-VECC-17 to 3-VECC-29; Technical Conference Transcript / Vol. 4 / pp. 72-75; U-Staff-177; U-EP-70; U-VECC-67; U-VECC-72 to U-VECC-79; Oral Hearing Transcripts / Vol. 6 / pp. 131-139; Oral Hearing Transcripts / Vol. 7 / pp. 1-16, 130-134; Oral Hearing Transcripts / Vol. 8 / pp. 72-74; Undertaking J7.4; and Undertaking J8.6.
[401] Oral Hearing Transcript / Vol. 6 / pp. 135-136.
[402] Argument-in-Chief / p. 48; and Oral Hearing Transcripts / Vol. 6 / pp. 137-139. In part, this is due to the completion of residential rate design (transitioning residential rates to fixed monthly charges), so that costs for serving the customers is fully recovered from rates invariant of changes in consumption for CDM or other factors.

Potential Load Growth

OEB staff notes that, beyond the load in the historical data on which the load forecast was developed (including the Spadina subway extension, which entered service in December 2017), there will be some additional load for Metrolinx's Crosstown LRT during the plan term.[403] In addition, OEB staff notes that the DRC evidence shows that there may be some other electrification of transit in Toronto Hydro's service territory (with related load growth) over the 2020-2024 period.[404] OEB staff agrees with Toronto Hydro that this load growth is likely to be immaterial (in consideration of other residential, commercial and institutional construction and growth also occurring in the City of Toronto).[405]

However, as discussed in sections 4.1 and 10.3, OEB staff has argued for a new methodology for calculating earnings sharing. The proposed revised methodology is based on a comparison of actual and deemed ROE (which uses actual net income as the foundation for the calculation). OEB staff notes that actual net income is directly influenced by actual load. If actual load is higher than the approved load forecast, all else being equal, actual net income and the associated ROE will be higher than the deemed amount. As such, Toronto Hydro will share the over earnings driven by higher load with ratepayers (after the 100 basis point deadband is surpassed) in the situation where actual load growth is higher than expected.[406]

6.2 Are Toronto Hydro's 2020 other revenue and shared services forecasts reasonable (Issue 4.2)?

OEB staff submits that Toronto Hydro's 2020 other revenue forecast should be increased by $1.78 million to reflect a more reasonable forecast for gains on disposition of utility assets and property.

OEB staff has no concerns with Toronto Hydro's shared services forecast.

[403] 3-Staff-106.
[404] Exhibit M2 / CUTRIC Report / p. 5.
[405] Oral Hearing Transcripts / Vol. 4 / p. 19.
[406] OEB staff notes that any balance recorded in the LRAMVA is expected to be removed from the ESM calculation to avoid double counting.

Other Revenue

Toronto Hydro's historical actual 2015-2019 other revenues and updated 2020 other revenue forecast is shown in the following table.[407]

Table 24
Other Revenues

USoA #	USoA Description	2015 Actual	2016 Actual	2017 Actual	2018 Actual	Bridge Year	Test Year
		2015	2016	2017	2018	2019	2020
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
4225	Late Payment Charges	$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
4082	Retailers' Fixed charge	$5,320	$5,280	$5,520	$5,280	$10,840	$10,840
4082	Retailers' Variable Charge	$257,269	$225,343	$178,662	$146,005	$342,772	$324,840
4082	Distributor Consolidated Billing (DCB) Charges	$143,718	$125,603	$106,118	$87,079	$198,415	$188,134
4082	Retail Consolidated Billing (RCB) Credit	-$9,072	-$8,351	-$635	$0	$0	$0
4084	Retailer Service Transaction Request	$13,764	$12,656	$10,350	$8,302	$18,563	$17,632
4084	Retailer Service Transaction Processing	$6,344	$5,722	$4,485	$3,190	$8,542	$8,162
4090/4086	SSS Admin Charge	$2,196,126	$2,317,539	$2,269,960	$2,313,558	$2,389,560	$2,407,409
4210	Parking Rental	$3,790	$1,200	$1,200	$4,408	$0	$0
4210	Property Rental	$41,516	$46,854	$53,414	$47,228	$0	$0
4215	TTC Rectification	$253,250	$303,900	$303,900	$303,900	$303,900	$303,900
4215	Settlement Discounts Taken	$404,384	$381,359	$523,847	$340,755	$389,382	$389,382
4215	Stale Dated Cheques	$453,706	$417,078	$736,416	$462,171	$533,368	$533,368
4220	Street Lighting	$7,055,723	$8,200,259	$9,229,601	$8,035,739	$8,536,375	$8,076,074
4325	Merchandise and Jobbing Revenue	$23,108,588	$32,769,384	$45,929,144	$47,400,242	$36,014,502	$37,732,615
4330	Merchandise and Jobbing Costs	-$14,047,565	-$19,805,704	-$29,913,621	-$27,406,949	-$15,651,688	-$15,991,089
4335	Gain/Loss on disposals	$211,338	$0	$0	$0	$0	$0
4375	Shared Services Recovery1	$2,927,027	$3,212,613	$4,829,010	$5,670,327	$5,494,615	$5,507,706
4355	Gain on Disposition of Utility and Other Property	$4,062,681	$2,132,160	$515,158	$576,205	$1,630,000	$0
4398	Foreign Exchange Gain/(Loss)	-$1,500,430	$162,383	$54,784	-$128,336	$0	$0
4405	Investment Interest Income	$1,298,537	$186,388	$9	$0	$120,000	$120,000
Specific Service Charges		$6,786,826	$9,497,848	$7,186,822	$5,966,102	$5,107,243	$3,689,939
Late Payment Charges		$4,126,310	$4,540,398	$3,696,196	$3,323,433	$3,732,947	$3,751,641
Other Operating Revenues		$10,825,837	$12,034,443	$13,422,839	$11,757,613	$12,731,715	$12,259,740
Other Income or Deductions		$16,060,177	$18,657,224	$21,414,483	$26,111,488	$27,607,430	$27,369,233
Total		$37,799,149	$44,729,912	$45,720,340	$47,158,636	$49,179,335	$47,070,553

With one exception, OEB staff accepts the updated 2020 other revenue forecast[408] including: (a) the change to the other income or deductions category to reflect the capitalization of major assets related to accident claims; (b) the change to the specific service charges category to reflect the revisions made to the OEB's Customer Service

[407] U-VECC-83. OEB staff understands that the response to U-VECC-83 includes all of the updates made to the other revenue forecast to date.
[408] U-VECC-83; and Undertaking J1.2.

Rules[409]; and (c) the change to retailer service charges category to reflect the approvals made by the OEB in a separate proceeding.[410]

OEB staff also notes that further updates to the 2020 other revenue forecast may be required at the draft rate order stage if there are any further generic updates made by the OEB to specific service charges.

OEB staff submits that the 2020 other revenue forecast of zero for gains on disposition of utility and other property is not reasonable. Toronto Hydro stated that at the time of the development of its application it did not have a plan to dispose of assets in 2020 and therefore there are no forecasted other revenues.[411] OEB staff asked Toronto Hydro about this issue again in its interrogatories on the application update. Toronto Hydro confirmed that its position remains the same.[412]

OEB staff notes that there have been gains from the disposition of utility and other property in each year 2015 to 2019.[413] Over the 5-year period, the total other revenues derived from this category was $8.92 million.[414] OEB staff submits that Toronto Hydro's position that there will be no sales in this category, for the first time in five years, is not reasonable. OEB staff believes that a reasonable forecast for the other revenues that will be generated through the disposition of utility and other property for 2020 is $1.78 million, which reflects the annual average for the 2015-2019 period.[415]

[409] EB-2017-0183.
[410] EB-2015-0304.
[411] Technical Conference Transcripts / Vol. 3 / pp. 25-26.
[412] U-Staff-179.
[413] U-VECC-83.
[414] OEB staff understands that the gains from the disposition of utility and other property total amount of $8.92 million excludes the sale of the 50/60 Eglinton Avenue property discussed in Exhibit 8 / Tab 1 / Schedule 1 / p. 11. For that property, Toronto Hydro proposed an alternative treatment whereby the net gains on sale will be returned to ratepayers through a rate rider (and not classified as a revenue offset).
[415] U-VECC-83. OEB staff notes that 2019 is a forecast year (as actuals are not available). However, in the originally filed evidence, at Exhibit 3 / Tab 2 / Schedule 2 / p. 1, there were no revenues associated with forecasted disposition of utility and other property for both 2018 and 2019. In Exhibit U / Tab 3 / Schedule 2 / Appendix and U-VECC-83, revenues were added for both of those years. As such, OEB staff assumes that the 2019 other revenue amount for this category is based on a known sale of an asset (and should form part of the annual average calculation).

Shared Services

OEB staff notes that Toronto Hydro's methodology with respect to its treatment of shared services has not changed since the last proceeding.[416] OEB staff agrees with Toronto Hydro that its allocation methodology for shared services and corporate costs is in accordance with the OEB's requirements as established in the Affiliate Relationship Code.[417] OEB staff has no concerns with Toronto Hydro's forecast revenues and costs associated with shared services.[418]

7. Operations, Maintenance and Administration (OM&A) Costs, Depreciation Expenses and Payments in Lieu of Taxes (PILs) (Issue 5.0)

7.1 Is the level of proposed 2020 OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained (Issue 5.1)?

Toronto Hydro's proposed 2020 OM&A expenditures, shown at the program level, are set out in the table that follows.[419]

Table 25
Proposed 2020 OM&A Expenditures

OM&A Program	2020 ($M)
Preventative and Predictive Overhead Line Maintenance	$ 6.00
Preventative and Predictive Underground Line Maintenance	$ 5.50
Preventative and Predictive Station Maintenance	$ 5.60
Corrective Maintenance	$ 17.20
Emergency Response	$ 16.60
Disaster Preparedness Management	$ 2.70
Control Centre Operations	$ 8.70
Customer-Driven Work	$ 10.60

416 Exhibit 4A / Tab 5 / Schedule 1.
417 Affiliate Relationship Code for Electricity Distributors and Transmitters / March 15, 2010.
418 Exhibit U / Tab 3 / Schedule 2; and Undertaking J8.9.
419 Exhibit 4A / Tab 1 / Schedule 1 / pp. 2-3 updated for Exhibit U / Tab 4A / Schedule 1 / pp. 1-2 and Exhibit 4A / Tab 2 / Schedule 18 / Appendix A (updated July 31, 2019).

Asset and Program Management	$ 13.90
Work Program Execution	$ 21.80
Fleet and Equipment Services	$ 11.00
Facilities Management	$ 24.00
Supply Chain Services	$ 12.60
Customer Care	$ 49.40
Human Resources and Safety	$ 15.90
Finance	$ 16.20
Information Technology	$ 44.00
Legal and Regulatory	$ 16.10
Charitable Donations and LEAP	$ 1.00
Common Costs and Adjustments	$ (0.70)
Allocations and Recoveries	$ (19.90)
Total OM&A	**$ 278.20**

The proposed 2020 OM&A expenditures of $278.2 million compared to OEB-approved 2015 OM&A expenditures of $243.9 million[420] is an increase of $34.3 million or 14.1%. The proposed 2020 OM&A expenditures compared to 2018 actual OM&A expenditures of $268.3 million[421] is an increase of $9.9 million or 3.7%. 2018 is the most recent year for which actuals are available.

Toronto Hydro stated that the rates that support its proposed 2020 OM&A expenditures reflect the minimum that Toronto Hydro requires to maintain safety, reliability and customer service outcomes, continue to operate effectively, and comply with all the legal and regulatory requirements.[422] OEB staff disagrees.

OEB staff submits that the proposed 2020 OM&A budget should be reduced by approximately $9.4 million (or approximately 3%) for the reasons that follow. OEB staff notes that this will reduce the proposed 2020 OM&A budget to approximately $268.8 million, which is nearly the same as the 2018 actual OM&A expenditures ($268.3 million).

OEB staff submits that reductions to the proposed 2020 OM&A expenditures should be made in the following categories:

[420] Exhibit U / Tab 4 / Schedule 1 / Appendix A.
[421] Exhibit U / Tab 4 / Schedule 1 / Appendix A.
[422] Argument-in-Chief / p. 50.

- Customer Care Program – $3.7 million reduction to address an overstatement of the forecast 2020 bad debt expense and external services costs associated with the management of bad debt

- Asset and Program Management Program - $1.2 million reduction associated with the removal of the forecast of CWIP write-offs

- Legal and Regulatory Program - $0.3 million reduction associated with the amortized one-time costs for the current application

- Overall OM&A Budget - $2.5 million reduction to the overall OM&A budget to reflect the inclusion of all the originally forecast cost savings related to the ERP project

- Staffing and Compensation - $3.2 million reduction to compensation costs to reflect the most recent forecast of the compensation costs. This has an impact on both the capital and OM&A budgets. OEB staff estimates that the impact on OM&A costs is about $1.7 million (with the remainder being applied to the capital budget).

OEB staff's detailed submissions on these issues follow. OEB staff has no other specific concerns with the proposed 2020 OM&A budget.

Customer Care

Toronto Hydro's forecasted 2020 expenditures for the customer care program are $49.4 million. This reflects an increase of $11.7 million (or 31%) relative to 2018 actual expenditures for this program.[423]

OEB staff submits that the aspect of this increase related to bad debt expense and external services for the management of bad debt are not appropriate. Therefore, a reduction of $3.7 million to the proposed 2020 expenditures in this program are necessary. OEB staff notes that the costs for this program, even after the reduction is applied, are $8 million higher than 2018 actuals.

[423] Exhibit U / Tab 4A / Schedule 1 / p. 8.

Toronto Hydro forecasted $6.8 million for bad debt (electricity accounts only) in 2020.[424] The actual bad debt in 2018 was $4.4 million[425], which is $2.1 million lower than the original bad debt forecast of $6.5 million.[426] Toronto Hydro's original forecast of bad debt expense for 2018 ($6.5 million), which reflected an increase over previous years, was largely based on the expected impact of the winter disconnection moratorium.[427]

Toronto Hydro has provided, throughout the proceeding, a number of explanations as to the expected impact of the winter disconnection moratorium on bad debt. The result of Toronto Hydro's analysis is an expectation that bad debt expense will increase over time.[428]

OEB staff notes that Toronto Hydro has now experienced two full winters with the winter disconnection moratorium in place.[429] OEB staff submits that the impact, on an actual basis, has not been to increase bad debt.[430] On that basis, OEB staff submits that Toronto Hydro's forecast of bad debt for 2020, which is significantly higher than the actual average experienced during the 2015-2018 period (all years for which actuals are available) is not appropriate. OEB staff submits that a forecast of 2020 bad debt expense (electricity accounts only) based on the actual average for the 2015-2018 period of $5.2 million is appropriate. This reflects a reduction of $1.6 million to the proposed 2020 bad debt expense.[431]

OEB staff also notes that, in 2018, there was a $2.1 million reduction in external services costs relative to the original forecast amount due to a "temporary underspend" in services needed to support the management of bad debt. Toronto Hydro stated that it plans to implement an alternative arrears management strategy to better align its operations with the seasonality of the new disconnection policy. The strategy is needed to ensure that residential bad debt costs continue to be managed in an effective way under the winter disconnections moratorium.[432] OEB staff submits that this new strategy

424 U-Staff-184(b).
425 U-Staff-184(b).
426 Exhibit 9 / Tab 1 / Schedule 1 / p. 30. OEB staff is referring to the bad debt forecast made in the current proceeding prior to the application update as the original bad debt forecast.
427 Exhibit 4A / Tab 2 / Schedule 14 / p. 21. Toronto Hydro discusses that the costs of the collections segment are expected to increase "primarily as a result of the OEB's winter disconnection moratorium."
428 Undertaking JTC3.10.
429 Oral Hearing Transcripts / Vol. 5 / p. 39.
430 U-Staff-184(b).
431 U-Staff-184(b). The total 2020 bad debt expense if OEB staff's proposal is accepted will be $5.5 million (including the non-electricity accounts) as compared to the proposed amount of $7.1 million.
432 U-Staff-184(a).

is related to Toronto Hydro's belief that the winter disconnection moratorium is going to have a very significant impact on bad debt expense and related management costs. As previously discussed, the winter disconnection moratorium has not had the impact that Toronto Hydro has predicted.[433] OEB staff believes that Toronto Hydro can effectively manage its bad debt in 2020 with a level of funding for external services related to the management of bad debt that is $2.1 million lower than Toronto Hydro's forecasted amount for 2020 (i.e. the temporary underspend experienced in 2018 should not be considered temporary).

Asset and Program Management

The 2020 asset and program management program budget of $13.9 million[434] includes $1.2 million related to CWIP write-offs.[435] Toronto Hydro explained that it has budgeted for CWIP write-offs as there is a high probability that at least some work will no longer be required (after having costs charged to CWIP) as a result of various factors.[436]

OEB staff submits that it is not appropriate for Toronto Hydro to forecast, in its OM&A budget, amounts related to work that it decides to start but not complete. OEB staff submits that Toronto Hydro needs to be prudent in deciding which projects it should start (and for which it should begin incurring costs that are recorded as CWIP). OEB staff is of the view that CWIP write-offs are entirely the responsibility of management and as such should not be recoverable from ratepayers on a forecast basis. Therefore, OEB staff submits that the $1.2 million related to CWIP write-offs should be removed from the asset and program management budget.

Legal and Regulatory

The one-time costs associated with the current Custom IR application are $9.44 million.[437] This compares to Toronto Hydro's actual application costs for its 2015-2019 Custom IR application of $6.07 million.[438] This also compares to Hydro One's forecast

[433] U-Staff-184(b).
[434] Exhibit U / Tab 4A / Schedule 1 / pp. 5-6.
[435] 4A-Staff-115(c).
[436] 4A-Staff-115(c).
[437] Updated Exhibit 4A / Tab 2 / Schedule 18 / Appendix A.
[438] Updated Exhibit 4A / Tab 2 / Schedule 18 / Appendix A.

costs for its 2018 distribution Custom IR application of $4.6 million[439] and for its 2020 transmission Custom IR application of $3.73 million.[440]

OEB staff submits that the costs associated with Toronto Hydro's 2020-2024 Custom IR application are not reasonable. The legal and consulting costs alone are $7.47 million, which is nearly $3 million higher than were incurred for Toronto Hydro's last proceeding on an actual basis.[441] Compared to Hydro One's (forecast) legal and consulting costs in its recent 2018 distribution Custom IR application and 2020 transmission Custom IR application, Toronto Hydro's legal and consulting costs are well more than double (based on an average of the two Hydro One applications).[442]

OEB staff submits that, while Toronto Hydro completed more work on its current application relative to the last application (including more expert studies), ratepayers should not be responsible for the entirety of the incremental legal and consulting costs incurred for the current application. OEB staff is of the view that a cost increase of $2.85 million for legal and consulting costs between the current application and the 2015-2019 Custom IR application is excessive. OEB staff submits that Toronto Hydro should have better controlled its legal and consulting costs.

For these reasons, OEB staff submits that Toronto Hydro's legal and consulting costs should be reduced by $1.43 million (resulting in a total application cost of $8.01 million). This amounts reflects a decrease of 50% of the incremental legal and consulting costs incurred for the current application ($7.47 million) relative to the 2015-2019 Custom IR application ($4.62 million).[443] OEB staff submits that the application costs should be amortized over the 5-year Custom IR term. As such, the total impact on 2020 revenue requirement of this argument is approximately $0.3 million.

OM&A Budget Reduction for ERP-related Cost Savings

As discussed in section 5.2, Toronto Hydro experienced cost overruns (relative to the forecasted amount) of $8 million related to its ERP project that was completed during the 2015-2019 Custom IR term.[444] In addition, there were significantly lower cost savings resulting from the project ($1.6 million) than were originally forecast ($4.1

[439] EB-2017-0049 / Exhibit C1 / Tab 5 / Schedule 2 / p. 1.
[440] EB-2019-0082 / Appendix 2-M.
[441] Updated Exhibit 4A / Tab 2 / Schedule 18 / Appendix A.
[442] EB-2017-0049 / Exhibit C1 / Tab 5 / Schedule 2 / p. 1; and EB-2019-0082 / Appendix 2-M.
[443] Updated Exhibit 4A / Tab 2 / Schedule 18 / Appendix A.
[444] U-Staff-166.3 / Appendix A; and Oral Hearing Transcripts / Vol. 5 / p. 113.

million).[445] While ratepayers are being asked to pay for the entire capital costs of the ERP project (including the cost overrun), Toronto Hydro has reflected only the actual cost savings that resulted from the project ($1.6 million) in its proposed OM&A costs (as these actual savings are reflected in Toronto Hydro's historical costs, which are used in forecasting its test year costs).[446]

OEB staff submits that Toronto Hydro should be held to the original forecast of the cost savings related to the ERP project. In situations where ratepayers are being asked to pay capital costs in excess of the amount that was originally approved and, at the same time, receiving less benefits (cost savings) than the OEB was assured would result from the approved capital spending, it is only reasonable that a utility be held to its cost saving forecast. On that basis, OEB staff submits that the OM&A budget should be reduced by $2.5 million to reflect the difference between the cost savings built into rates and the forecasted cost savings, which informed the OEB's approval of the capital project.

OEB staff notes that Toronto Hydro discussed ERP-related cost savings associated with overtime costs of $1.5 million that formed part of the original forecast of the total cost savings ($4.1 million). Toronto Hydro noted that as these savings are not directly attributable to the ERP project they have not been reflected in the cost savings for the project on an actual basis.[447] However, Toronto Hydro stated that its overtime costs have been trending downwards due to various initiatives undertaken during the 2015-2019 period.[448] OEB staff submits that as these cost savings cannot be directly attributed to the ERP project (and could have resulted from any number of undertakings), the OEB should not consider these savings in the calculation of the OM&A budget reduction related to the ERP cost savings (i.e. forecast cost savings of $4.1 million minus actual cost savings $1.6 million). In any case, it is not clear to OEB staff what downward trend Toronto Hydro is referring to as the actual overtime costs in 2015 were $12.6 million and increased to $17.1 million in 2018 (which is the most recent year for which actual information is available).[449]

[445] Undertaking JTC3.4 / Table 1; and Undertaking JTC3.4 / Table 2.
[446] Undertaking JTC3.4 / Table 2; Oral Hearing Transcripts / Vol. 5 / p. 117; and Argument-in-Chief / p. 57.
[447] Undertaking JTC3.4 / p. 3; and Oral Hearing Transcripts / Vol. 5 / p. 116.
[448] Undertaking JTC3.4 / p. 3.
[449] U-Staff-166.11.

Workforce Staffing and Compensation

Toronto Hydro's full-time equivalent (FTE) count and compensation amount for the 2015-2019 historical period and the 2020 test year proposal is set out in the following table.[450]

Table 26
FTE Count and Compensation

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Number of Employees						
Executive	6	6	7	5	5	5
Managerial	55	63	63	67	63	62
Non Management, Non-Union	495	521	549	564	607	603
Society	53	56	60	65	68	69
PWU	874	837	794	724	779	778
Total	**1483**	**1484**	**1473**	**1425**	**1523**	**1517**
Total Compensation						
Executive	$3,085,275	$2,963,967	$3,336,959	$2,918,562	$3,009,528	$3,153,935
Managerial	$12,780,825	$15,107,977	$15,837,777	$17,107,012	$17,115,660	$17,617,093
Non Management, Non-Union	$69,286,521	$72,389,780	$77,281,663	$82,371,631	$91,771,915	$95,640,075
Society	$8,459,748	$8,535,654	$9,831,580	$10,416,204	$11,433,197	$12,007,672
PWU	$17,483,204	$113,361,107	$110,138,140	$104,908,173	$109,566,235	$113,045,032
Total	**$211,095,573**	**$212,358,484**	**$216,426,119**	**$217,721,582**	**$232,896,535**	**$241,463,807**

Toronto Hydro noted that its compensation costs make up approximately 46% of the overall OM&A budget.[451]

OEB staff notes that Toronto Hydro's proposed 2020 FTE count (1,517) reflects a modest increase of 34 FTEs (or 2.3%) relative to 2015 actuals (1,483). The proposed

450 U-SEC-102.
451 Argument-in-Chief / p. 56.

2020 compensation costs are $241.5 million, which reflects an increase of $30.4 million (or 14.4%) relative to 2015 actuals ($211.1 million).[452] OEB staff submits that the proposed FTE count and compensation costs are generally reasonable.

The compensation costs are supported by a benchmarking study for non-executive positions. The benchmarking study highlights that Toronto Hydro's compensation is generally, with a few exceptions for certain job grades, closely aligned with the 50th percentile compensation of the energy peer group and below 50th percentile compensation of the general industry peer group.[453] Toronto Hydro also provided benchmarking information with respect to its executive compensation.[454]

OEB staff submits that Toronto Hydro's proposed compensation costs are well supported by the benchmarking information.

However, OEB staff notes that Toronto Hydro's proposed 2020 FTE count and related compensation amount are not based on the most recent information. Toronto Hydro's most recent FTE forecast for 2020 is 1,491[455], which is 26 FTEs lower than the proposed amount of 1,517.[456] This FTE reduction results in compensation costs that are $3.2 million lower than the proposed amount.[457]

Toronto Hydro states that despite the decreases in FTEs and compensation identified in Undertaking J5.2, the utility is committed to delivering the proposed programs in 2019 and 2020. Therefore, Toronto Hydro requires the requested level of OM&A funding to complete the work. To the extent that Toronto Hydro does not have the sufficient internal resources to deliver its programs, the utility plans to rely on external service providers to complete the work.[458]

OEB staff notes that Toronto Hydro has not quantified the forecasted increase in 2020 external labour costs that would be required to replace the reduced FTEs. OEB staff submits that there is no evidence as to whether these external labour costs, if they were

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452 U-SEC-102.
453 Exhibit 4A / Tab 4 / Schedule 5 / p. 1.
454 4A-SEC-90.
455 Undertaking J5.2 / Appendix A.
456 U-SEC-102.
457 Undertaking J5.2 / Appendix A. The total compensation costs based on the most recent update are $238.3 million.
458 Undertaking J5.2 / p. 1.

to actually be incurred, would entirely offset the reduced internal compensation costs (based on the latest forecast).

In addition, OEB staff submits that Toronto Hydro should be able to find the necessary efficiencies to complete its planned work with slightly lower labour costs in 2020 (based on the most recent forecast of FTEs). For those reasons, OEB staff submits that the proposed 2020 compensation costs should be reduced by $3.2 million. This amount should be reflected as a reduction to the revenue requirement (both OM&A and capital-related as appropriate). OEB staff estimates that the impact on OM&A costs is about $1.7 million (with the remainder being applied to the capital budget).[459]

With respect to OPEBs, as part of its 2015-2019 Custom IR proceeding[460], Toronto Hydro was directed to recover the cash amount associated with its OPEB costs in rates and to track the variance between cash and accrual in an OEB approved variance account. This was an interim measure that was ordered by the OEB pending the completion of the OEB's generic consultation on the regulatory treatment of pension and OPEB costs.[461]

On September 14, 2017, the OEB released its *Report on the Regulatory Treatment of Pension and OPEB Costs* (OEB Pension and OPEB Report).[462] This report established the use of accrual method as the default methodology for the purpose of recovering pension and OPEB costs in rates. This is Toronto Hydro's first rebasing since this report was issued.

OEB staff submits that it supports Toronto Hydro's use of the accrual method for purposes of recovering its pension and OPEB costs because it is consistent with the default methodology set out in the OEB Pension and OPEB Report. As OEB staff discusses in section 10.3, Toronto Hydro will track the difference between cash and accrual in Account 1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account, and provide ratepayers with an asymmetrical carrying charge on the cumulative differential balance tracked in this account (i.e. when the cumulative forecast accrual balance exceeds the cumulative actual cash payments made).

[459] The estimate is based on a 54% ratio of compensation costs being allocated to OM&A as shown in 4A-SEC-87(a).
[460] EB-2014-0116.
[461] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 13.
[462] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017.

7.2 Are Toronto Hydro's proposed depreciation expenses (including decommissioning provision and derecognition) for 2020-2024 appropriate (Issue 5.2)?

Toronto Hydro's proposed 2020-2024 depreciation expense is set out in the following table.[463]

Table 27
Proposed 2020-2024 Depreciation Expense

	2020	2021	2022	2023	2024	Total
Depreciation	$239.75	$254.53	$265.40	$285.76	$298.66	$1,344.09
Derecognition	$25.80	$27.00	$26.90	$28.30	$28.50	$136.50
Total	**$265.55**	**$281.53**	**$292.30**	**$314.06**	**$327.16**	**$1,480.59**

The depreciation expense (including derecognition) is part of the 2020 revenue requirement and is required for the 2021-2024 CPCI calculation.[464] OEB staff has no direct concerns with the depreciation expense or the derecognition expense proposed for the 2020-2024 period.[465] OEB staff also has no concerns with the decommissioning provision.[466]

OEB staff notes that its arguments set out in section 5.1 with respect to the Copeland Phase 1 rate base reduction and in section 5.2 for reductions to the proposed capital expenditures will have an impact on both depreciation expense and derecognition expense if accepted by the OEB.

Toronto Hydro calculates depreciation expense based on the month that an asset comes into service (as opposed to using the half-year rule).[467] OEB staff submits that this is the appropriate methodology to use in the calculation of deprecation expense

[463] Depreciation expense is from U-Staff-168 / Appendix A / Net Fixed Asset Schedules. The derecognition expense is from Undertaking JTC1.1. OEB staff notes that the total annual expense for both depreciation and derecognition combined matches the depreciation expense provided in Undertaking J8.5, which is the latest depreciation expense provided and includes the updates made in the original filing of Undertaking J1.2 (July 2, 2019). The updated filing of Undertaking J1.2 (July 31, 2019) has no impact on depreciation expense.
[464] Specifically, the depreciation expense (which forms parts of the capital-related revenue requirement) is part of the C-factor calculation.
[465] U-Staff-168 / Appendix A; and Undertaking JTC1.1.
[466] Exhibit 4B / Tab 1 / Schedule 1 / p. 5.
[467] Exhibit 4B / Tab 1 / Schedule 1 / p. 3.

when monthly information is available. OEB staff submits that using monthly information provides for the best possible forecast of depreciation expense. OEB staff notes that, in section 5.1, it argued that rate base should also be calculated using monthly information for in-service additions. Using monthly information for both in-service additions and depreciation expense would appropriately align the approach.

OEB staff notes that the forecast of derecognition expense is calculated based on the historical relationship between derecognition expense and capital expenditures applied to forecast capital expenditures.[468] OEB staff has no concerns with the proposed methodology as there is relatively consistent relationship between derecongition and capital expenditures based on historical actuals.[469] Due to the methodology used by Toronto Hydro to forecast derecognition expense, if the OEB accepts OEB staff's submission with respect to the proposed reduction to forecast capital expenditures, it is expected that forecast derecognition would also be reduced.

OEB staff submits that the derecognition variance account should stop recording new principal activity as of December 31, 2019 (and can be closed after the 2019 balance in the account is disposed as part of the 2021 Custom IR update application) as discussed in section 10.3. OEB staff notes that the account was originally established as there was expected to be large variances between actual and forecast derecognition expense. 2015 was the first year that Toronto Hydro had to incur derecognition expense in accordance with International Financial Reporting System (IFRS) and as such, had no experience in forecasting derecognition expense at that time.[470]

OEB staff notes that the account is symmetrical in nature and records both positive and negative variances between actual and forecast.[471] Toronto Hydro now has five years of experience with forecasting derecognition expense and stated that it is more comfortable with its 2020-2024 forecasts.[472] OEB staff submits that Toronto Hydro should be required to take the risk associated with derecognition expense if its forecast is lower than the actual derecognition expense that is incurred. As such, the account should no longer record balances beginning in 2020 (and be closed after the disposition of the 2019 balance in the 2021 Custom IR update application). Any variances in derecognition expense should be recorded in the CRRRVA, which is the same

[468] 4B-Staff-141(b).
[469] 4B-Staff-141(b).
[470] Oral Hearing Transcripts / Vol. 4 / p. 146.
[471] Exhibit 9 / Tab 1 / Schedule 1 / p. 19.
[472] Oral Hearing Transcripts / Vol. 4 / p. 146.

treatment that is applied to depreciation expense. The CRRRVA is an asymmetrical account whereby Toronto Hydro has to refund amounts if the forecast capital-related revenue requirement is higher than the actual capital-related revenue requirement. However, if the forecast capital-related revenue requirement is lower than the actual capital-related revenue requirement, Toronto Hydro is not allowed to recover those amounts from ratepayers.

OEB staff also notes that Toronto Hydro has a number of asset classes for which the useful life applied to determine depreciation expense is outside the range established in the Kinectrics Report completed for the OEB.[473] For nearly all asset classes where Toronto Hydro's proposed useful life is outside the Kinectrics range, the useful life applied is shorter.[474] The useful lives applied by Toronto Hydro are largely based on an August 2009 report completed by Kinectrics for Toronto Hydro specifically.[475] OEB staff submits that Toronto Hydro should complete a new study specifically for its asset classes that it applies useful lives that are outside of the range set out in the Kinectrics Report completed for the OEB[476] and file this study with its next cost-based application.

7.3 Are Toronto Hydro's proposed PILs and other tax amounts for 2020-2024 appropriate (Issue 5.3)?

Toronto Hydro's proposed 2020-2024 PILS amounts are summarized in the following table.[477]

Table 28
Proposed 2020-2024 PILs Amounts

($M)	2020	2021	2022	2023	2024	Total
PILs	$12.7	$22.0	$13.4	$27.8	$40.4	**$116.3**

[473] Kinectrics Report – Asset Depreciation Study for the Ontario Energy Board / July 8, 2010.
[474] 4B-Staff-139.
[475] Toronto Hydro Electric System Useful Life of Assets / August 2009.
[476] Kinectrics Report – Asset Depreciation Study for the Ontario Energy Board / July 8, 2010.
[477] Undertaking J8.5. This reflects the latest PILs amounts provided and includes the updates made in the original filing of Undertaking J1.2 (July 2, 2019). The updated filing of Undertaking J1.2 (July 31, 2019) has no impact on PILs.

The PILs amount is part of the 2020 revenue requirement and is required for the 2021-2024 CPCI calculation.[478] OEB staff submits that the PILs amounts should be updated at the draft rate order stage.

Toronto Hydro is also seeking to recover $5.5 million related to its property tax costs for the test period 2020.[479] OEB staff notes that the 2020 amount is consistent with the actual historical trend for property taxes for the period 2015-2018. Therefore, OEB staff submits that the amount appears to be reasonable.

PILs

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-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 which it indicated that it expects

[478] Specifically, the PILs amount (which forms parts of the capital-related revenue requirement) is part of the C-factor calculation.
[479] Exhibit U / Tab 4A / Schedule 1 / p. 7.

utilities to reflect the aforementioned CCA rule changes in their cost-based applications for 2020 rates and beyond.[480]

Toronto Hydro updated the PILs calculations in order to reflect the revenue requirement impact of the new CCA rules for the period 2019-2024.[481] The PILs amounts presented in Table 28 includes the projected impacts of the AII program.

OEB staff notes that Toronto Hydro indicated the following with respect to its updated PILs calculations, which reflected the impact of the AII program.

> Please see Appendix A for the estimated updated PILs requirement calculations and supporting CCA tables for the 2019-2024 period that reflect Toronto Hydro's current understanding of the new accelerated CCA rules. These estimates are based on assumptions that may materially change as the legislation is finalized and as new information becomes known and is assessed.[482]

At the time Toronto Hydro filed its updated PILs calculations, the legislation enacting the new CCA rules had not been passed. However, since then, the new rules received Royal Assent and are now fully enacted. Furthermore, Toronto Hydro has since filed its 2018 tax return under the new CCA rules. Therefore, OEB staff submits that, as part of the draft rate order in this proceeding, Toronto Hydro should update its PILs estimates based on its more up-to-date understanding of the tax changes, and incorporate any changes in assumptions or new information within its 2020-2024 PILs calculations.

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.[483]

Toronto Hydro indicated that its existing CRRRVA would capture the 2018 and 2019 revenue requirement impacts of the CCA rule changes.[484]

[480] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.
[481] U-Staff-188 / Table 1.
[482] U-Staff-188(b).
[483] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.
[484] U-Staff-188 (d).

The CRRRVA captures the variance between the actual capital-related revenue requirement and the capital-related revenue requirement approved in rates during the Custom IR term.[485] The capital-related revenue requirement includes PILs.[486]

OEB staff notes that the CCA rule change relates entirely to the amount of CCA deduction that can be taken on capital additions in a given year. Since the CRRRVA is designed to capture the revenue requirement impact associated with a variance in the projected in-service additions for the plan period, it would include any variance between the projected CCA and actual CCA on the in-service additions. As such, OEB staff agrees with Toronto Hydro that the CRRRVA will properly capture the 2018 and 2019 revenue requirement impact of the new CCA rules. Based on this, Toronto Hydro would not need to use the new sub-account of Account 1592 that the OEB established for this purpose.[487]

OEB staff notes however, that Toronto Hydro's CRRRVA was designed to protect ratepayers in the event that the actual capital-related revenue requirement is less than the amount funded through rates (it is asymmetrical in favour of ratepayers). Therefore, it is possible that amounts accumulated within the CRRRVA do not get disposed of by virtue of the fact that the actual cumulative capital-related revenue requirement exceeds what was funded in rates for the previous Custom IR term (2015-2019). By using the CRRRVA instead of Account 1592, there is a risk that the 2018 and 2019 revenue requirement impacts pertaining to the CCA rule changes may not actually be refunded to ratepayers because they were offset by other components of the capital-related revenue requirement.

However, in the current circumstances, OEB staff submits that this risk is very low given that the 2018 audited balance in the CRRRVA account (which does not include any impacts related to the CCA rule changes) is sitting in a credit position (refund to ratepayers) and the account is forecast to continue to be in a large credit position to the end of 2019.[488] As such, OEB staff has no concerns with the use of the CRRRVA to record the 2018 and 2019 revenue requirement impacts pertaining to the CCA rule changes.

[485] Exhibit 9 / Tab 1 / Schedule 1 / p. 10.
[486] Undertaking J8.5.
[487] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.
[488] Exhibit U / Tab 9 / Schedule 1 / p. 2.

OEB staff notes that it does not appear that Toronto Hydro has calculated and included any amount within its CRRRVA related to the 2018 revenue requirement impact of the new CCA rules. OEB staff submits that Toronto Hydro should update its CRRRVA to include the 2018 revenue requirement impact in the draft rate order stage of the proceeding. Toronto Hydro has already filed its 2018 tax return under the new CCA rules and therefore the impact on the 2018 revenue requirement should be known.

In its Argument-in-Chief, Toronto Hydro amended the balance in its CRRRVA to include the 2019 revenue requirement impact of the new CCA rules.[489] This amount is included in the 2019 projected principal activity balance of the CRRRVA. OEB staff submits, in the context of its proposal, set out in section 10.2, that 2019 forecast balances in the Group 2 deferral and variance accounts are not disposed until the 2021 Custom IR proceeding, Toronto Hydro should revisit its calculation of the 2019 CCA-related impact as part of that future proceeding.

OEB staff also submits that, if for some reason the large credit that is currently forecast in the CRRRVA for 2019 does not materialize (i.e. the account ends in a debit) and thereby offsets any refund to ratepayers related to the 2019 revenue requirement impact of the new CCA rules, in accordance with the OEB's July 25th, 2019 letter[490], the amounts pertaining to the 2019 revenue requirement impact of the new CCA rule changes should be moved from the CRRRVA and into the new sub-account of 1592.

8. Cost of Capital (Issue 6.0)

8.1 Are Toronto Hydro's proposed 2020-2024 cost of capital amounts (interest on debt and return on equity) appropriate (Issue 6.1)?

Toronto Hydro's proposed cost of capital amounts for the 2020-2024 period are set out in the following table.[491]

[489] Argument-in-Chief / p. 71. Toronto Hydro indicated that it has included an amount of $10.5 million in the projected 2019 principal activity for the CRRRVA. The $10.5 million was provided as part of Toronto Hydro's response to U-Staff-188.
[490] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.
[491] Undertaking J8.5. This includes the updates made in the original filing of Undertaking J1.2 (July 2, 2019). The updated filing of Undertaking J1.2 (July 31, 2019) has no impact on the cost of capital.

Table 29
Proposed 2020-2024 Cost of Capital

	2020	2021	2022	2023	2024	Total
Return on Equity	$162.00	$170.40	$179.10	$189.30	$198.90	$899.70
Deemed Interest Expense	$100.20	$105.40	$110.80	$117.10	$123.00	$556.50
Cost of Capital	**$262.20**	**$275.80**	**$289.90**	**$306.40**	**$321.90**	**$1,456.20**

OEB staff has no direct concerns with the cost of capital amounts for the 2020-2024 period. OEB staff notes that its arguments for reductions to rate base (section 5.1) and capital expenditures (section 5.2) will reduce the cost of capital if these arguments are accepted by the OEB.

Toronto Hydro proposed to use the OEB's deemed capital structure in its calculation of the cost of capital. More specifically, Toronto Hydro proposed a debt to equity split of 60% debt (including 4% short-term debt) and 40% equity.[492] OEB staff has no concerns with Toronto Hydro's proposed capital structure.

Toronto Hydro proposed to use the OEB-approved 2020 ROE value in the calculation of its 2020 revenue requirement and the CPCI for the 2021-2024 period.[493] Toronto Hydro estimated the 2020 ROE to be 8.82%, which is the value used throughout the application in the calculation of the cost of capital.[494] OEB staff accepts Toronto Hydro's proposal to use the most recently OEB-approved ROE percentage to calculate the return component of its 2020 revenue requirement and in the CPCI calculation for the 2021-2024 period. OEB staff notes that the ROE component of the cost of capital will need to be updated at the draft rate order stage of the proceeding to reflect the most recently OEB-approved percentage.

Toronto Hydro is assigned long-term debt through promissory notes from its parent, Toronto Hydro Corporation. The promissory notes are written on the same terms as Toronto Hydro Corporation's debt plus a five basis point fee for administration.[495] OEB

[492] Exhibit 5 / Tab 1 / Schedule 1 / p. 1.
[493] The ROE amount (which forms parts of the capital-related revenue requirement) is used in the C-factor calculation.
[494] Exhibit 5 / Tab 1 / Schedule 1 / p. 2.
[495] Exhibit 5 / Tab 1 / Schedule 1 / pp. 4-5.

staff submits that Toronto Hydro's proposed long-term debt rate of 3.71% is reasonable.[496]

With respect to short-term debt, Toronto Hydro uses one-month Bankers' Acceptance rates as a proxy for its short-term debt rate.[497] OEB staff submits that the proposed 2020 short-term debt rate of 2.61%[498] derived using the noted proxy approach is reasonable.

Toronto Hydro applied the weighted average forecasted debt rates to determine its deemed interest expense for the 2020-2024 period.[499] OEB staff submits that this approach is appropriate.

9. Cost Allocation and Rate Design (Issue 7.0)

9.1 Are Toronto Hydro's cost allocation and revenue-to-cost ratio proposals appropriate (Issue 7.1)?

The cost allocation model for 2020 was updated in Exhibit U / Tab 7 / Schedule 1 to reflect a number of corrections and updated forecasts.[500] OEB staff submits that it has no concerns with Toronto Hydro's cost allocation methodology as it appropriately relies on the OEB's cost allocation model.

OEB staff notes that the revenue-to-cost ratios (after rate design) for all rate classes are within the OEB's guideline ranges as shown in the table below. The table shows both the updated ratios and originally filed revenue-to-cost ratios.[501]

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496 Exhibit 5 / Tab 1 / Schedule 2 / p. 2. There were no updates to the cost of debt included in Exhibit U / Tab 5 / Schedule 1 relative to the original filing.
497 Exhibit 5 / Tab 1 / Schedule 1 / pp. 6-7.
498 Exhibit 5 / Tab 1 / Schedule 2 / p. 2. There were no updates to the cost of debt included in Exhibit U / Tab 5 / Schedule 1 relative to the original filing.
499 The deemed interest expense (which forms parts of the capital-related revenue requirement) is part of the 2020 revenue requirement. The deemed interest expense is used in the C-factor calculation for the 2021-2024 period.
500 Exhibit U / Tab 7 / Schedule 1. The full list of corrections and updates reflected are described at Exhibit U / Tab 7 / Schedule 1 / p. 1.
501 Exhibit U / Tab 8 / Schedule 1 / p. 2.

Table 30
Proposed Revenue to Cost Ratios (after Rate Design)

Rate Class	Original R/C ratio	Updated R/C ratio	OEB's Guideline Ranges
Residential	103.2	103.2	85-115
CSMUR[502]	100.0	100.0	
GS <50 kW	89.8	89.5	80-120
GS 50-999 kW	105.3	105.8	80-120
GS 1000-4999 kW	95.0	91.2	80-120
Large Use	85.0	88.8	85-115
Streetlighting	108.9	108.9	80-120
USL	94.7	120.0	80-120

OEB staff notes that there have been a number of updates to the revenue requirement made by Toronto Hydro since the cost allocation model was last run.[503] In addition, OEB staff has made a number of submissions that, if accepted, would also need to be reflected in the costs allocated to all rate classes and ultimately recovered from the ratepayers in each rate class. As such, OEB staff submits that Toronto Hydro should reflect the impact of the application updates and the OEB's final decision in the cost allocation model at the draft rate order stage of the proceeding.

9.2 Are Toronto Hydro's proposals for rate design (including, but not limited to, fixed / variable split, loss factors, retail transmission service rates, specific and other charges) appropriate (Issue 7.2)?

OEB staff has no concerns with Toronto Hydro's rate design proposals. The rate design issues are discussed in more detail below.

[502] Exhibit 7 / Tab 1 / Schedule 1 / p. 6. The rates for the CSMUR class are set to maintain a revenue to cost ratio equal to 1 to ensure that this is class is recovering its fully allocated costs. This is in accordance with the OEB's decision in the EB-2010-0142 proceeding.
[503] Updated Undertaking J1.2 (July 31, 2019).

Fixed / Variable Split

OEB staff accepts Toronto Hydro's proposal to maintain the fixed / variable spilt at the OEB-approved 2015 ratios for the 2020-2024 period for all rate classes, with the exception of the residential and competitive sector multi-unit residential (CSMUR) classes. For the residential and CSMUR rate classes, 2020 is the final year of the transition to fully fixed rates in accordance with OEB policy on residential rate design.[504] OEB staff notes that the change in the monthly fixed charge for the residential and CSMUR classes does not exceed the threshold whereby rate mitigation would be required.[505]

Transformer Allowance

OEB staff accepts Toronto Hydro's proposal to maintain the transformer allowance credit of $0.62/kVA per 30 days.[506] This reflects no change to the transformer allowance credit relative to the last proceeding.

Standby Rates

OEB staff notes that Toronto Hydro's standby rates are approved on an interim basis and it proposed to continue this treatment.[507] OEB staff accepts Toronto Hydro's proposal to continue its existing practice with respect to the application and calculation of standby rates.[508] OEB staff notes that Toronto Hydro provided examples of how standby rates are applied in different generation output scenarios.[509]

Loss Adjustment Factors

OEB staff submits that Toronto Hydro properly complied with the OEB's decision in the 2015-2019 Custom IR proceeding, which required Toronto Hydro to update its loss factors in its next rebasing application.[510] OEB staff also submits that the loss factors for all rate classes have been calculated correctly.

[504] EB-2012-0410 / OEB Residential Rate Design Policy / April 2, 2015.
[505] Exhibit 8 / Tab 1 / Schedule 1 / p. 4.
[506] Exhibit 8 / Tab 1 / Schedule 1 / p. 5.
[507] Exhibit 8 / Tab 3 / Schedule 2 / p. 7.
[508] Exhibit 8 / Tab 1 / Schedule 1 / p. 6.
[509] 8-Staff-146(b).
[510] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 46.

Toronto Hydro filed an engineering study supporting its change to the loss factor for the Large User rate class and used the OEB's standard approach for forecasting loss factor for all other rate classes (in accordance with Appendix 2-R of the Chapter 2 Filing Requirements).[511] The proposed loss factors for all rate classes have reduced relative to the previously approved amounts.[512]

Retail Transmission Service Rates

OEB staff submits that Toronto Hydro has appropriately calculated the RTSRs based on the currently approved Uniform Transmission Rates (UTRs).[513] As proposed by Toronto Hydro, the RTSRs will need to be updated at the draft rate order stage to reflect the most recent OEB-approved UTRs.[514] In addition, as proposed by Toronto Hydro, the RTSRs should be updated each year, in the Custom IR update applications, to reflect the most recently approved UTRs at the time.[515]

Retailer Service Charges

As discussed in section 6.2, Toronto Hydro updated its other revenue forecast to reflect the OEB's approval of updated retailer service charges.[516] OEB staff submits that the updated retailer service charges should be reflected in Toronto Hydro's tariff filed as part of the draft rate order process.

Regulatory Charges

OEB staff submits that the regulatory charges (i.e. Wholesale Market Service Rate, Capacity Based Recovery, Rural and Remote Protection and Smart Metering Entity charges) provided as part of the pre-filed evidence[517] should be updated at the draft rate order stage to reflect the most recent OEB approvals with respect to those charges (as applicable). As proposed by Toronto Hydro, if these charges were to change during the Custom IR term, the updated charges should be reflected in the annual Custom IR update applications.[518]

[511] Exhibit 8 / Tab 1 / Schedule 1 / pp. 9-10.
[512] Exhibit 8 / Tab 1 / Schedule 1 / p. 10.
[513] Exhibit 8 / Tab 1 / Schedule 1 / pp. 7-8.
[514] Argument-in-Chief / p. 66.
[515] Exhibit 8 / Tab 1 / Schedule 1 / p. 8.
[516] U-VECC-83. The OEB approved updated retailer service charges in EB-2015-0304.
[517] Exhibit 8 / Tab 1 / Schedule 1 / p. 8.
[518] Exhibit 8 / Tab 1 / Schedule 1 / p. 8.

Specific Service Charges

OEB staff has no concerns with Toronto Hydro's proposals with respect to its specific service charges. Specifically, Toronto Hydro proposed to maintain its specific service charges at the existing levels, with the exception of: (a) the collection of account and install / remove load control device charges; (b) specific charge for access to power poles (wireline attachments); and (c) service call – customer owned equipment charge.[519]

OEB staff submits that Toronto Hydro's proposal to remove the collection of account and install / remove load control device charges (both during regular hours and after hours)[520] is in accordance with the OEB order in the Custom Services Rules Review.[521] This change was reflected in the updated other revenue forecast.[522]

OEB staff submits that Toronto Hydro's proposal to update the specific charge for access to power poles (wireline attachments) is in accordance with the OEB's Report on Wireline Pole Attachment charges.[523] Toronto Hydro forecasted this charge to be $44.15 for 2020.[524] The specific charge for access to power poles (wireline attachments) should be updated at the draft rate order stage to reflect the OEB-approved inflation factor for 2020 once it is available.

With respect to the proposed removal of the service call – customer owned equipment charge, OEB staff agrees with Toronto Hydro's proposal. OEB staff agrees with Toronto Hydro that the scope of work that could be perceived to fall under this charge is too broad and the costs for this type of work is more appropriately recovered by invoicing individual customers for the actual services required (on a cost basis).[525]

[519] Undertaking J1. 2; U-Staff-178; and Exhibit 8 / Tab 2 / Schedule 1 / pp. 1-2.
[520] Exhibit J1.2; and U-Staff-178.
[521] EB-2017-0183.
[522] U-VECC-83.
[523] EB-2015-0304.
[524] Exhibit 8 / Tab 2 / Schedule 1 / p. 3. This reflects the OEB-approved 2019 charge of $43.63 escalated by the forecast 2020 inflation factor of 1.2%.
[525] Exhibit 8 / Tab 2 / Schedule 1 / p. 2; and 8-Staff-147.

9.3 Is Toronto Hydro's approach to cost responsibility for customer service charges under its Conditions of Service appropriate (Issue 7.3)?

Toronto Hydro describes a number of isolation and customer / temporary services that are included in its Conditions of Service.[526] Toronto Hydro invoices the individual customers based on the actual costs to provide these isolation and customer / temporary services. Toronto Hydro includes the revenues generated from these services as other revenues, which offset the revenue requirement.[527] OEB staff accepts that these types of services are best charged on an actual costs basis (as opposed to through a generic specific service charge).

OEB staff notes that the only issue raised, throughout the proceeding, with respect to Toronto Hydro's Conditions of Service was Toronto Hydro's original proposal to change its person in attendance policy for vault access for customer-owned vaults. Toronto Hydro confirmed that it withdrew its proposal to amend the current policy of attending one vault entry per year at no charge. Toronto Hydro also stated that it has no plan to amend this policy.[528] Toronto Hydro's position (i.e. that it was no longer changing its policy with respect to customer-owned vaults) was communicated to its customers on March 26, 2019.[529]

OEB staff agrees with Toronto Hydro's current proposal to continue providing free vault access (once each year). OEB staff submits that this approach should continue until, at least, the next rebasing (2025), as any additional revenues that are generated from a new charge should be reflected in the other revenue forecast prior to being implemented.

[526] 8-Staff-148 / Appendix A.
[527] 8-Staff-148(b).
[528] Argument-in-Chief / p. 68.
[529] Undertaking J6.11.

10. Accounting and Deferral and Variance Accounts (Issue 8.0)

10.1 Have the impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate treatment for each of these impacts appropriate (Issue 8.1)?

Toronto Hydro adopted and applied three new accounting standards effective January 1, 2018 as required by the International Accounting Standards Board. The new standards are:

- IFRS Financial Instruments (IFRS 9)
- IFRS Revenue from Contract with Customers (IFRS 15)
- IFRS Lease (IFRS 16)[530]

OEB staff has no concerns related to the impact of the above accounting standard changes. OEB staff notes that IFRS 9 and IFRS 15 have no impact on the revenue requirement.[531]

With respect to IFRS 16, the new standard effectively eliminated the classification of an operating lease and now requires that virtually all lease arrangements be accounted for as capital leases. Capital leases are recognized as assets on the balance sheet and depreciated over their lease term.

Prior to IFRS 16, lease costs associated with operating leases were recovered in rates as part of OM&A expense.

As a result of IFRS 16, operating lease costs that were previously recovered in rates through OM&A will now form part of rate base and be eligible to attract a return. However, this treatment is consistent with how capital leases have historically been treated for ratemaking purposes.

Toronto Hydro confirmed that the 2018 and 2019 revenue requirement impact associated with the change in the leases accounting standard was less than $0.1 million.[532] As such, OEB staff submits that there is no need to establish a variance

[530] Exhibit 1C / Tab 3 / Schedule 1 / pp. 1-3.
[531] Exhibit 1C / Tab 3 / Schedule 1 / pp. 1-3.
[532] 1C-Staff-49.

account to capture the transitional impact of the accounting standard change on the approved 2018 and 2019 revenue requirements as the amount is immaterial.

OEB staff notes that Toronto Hydro also mentioned accounting changes related to OPEBs and monthly billing costs in its Argument-in-Chief.[533] OEB staff's submission with respect to OPEBs was previously set out in section 7.1, which noted that OEB staff supports the use of the accrual method to recover these costs. OEB staff does not view the inclusion of monthly billing costs in OM&A as an accounting change. This is simply the reflection of new costs in the OM&A budget due to an increase in billing activity. OEB staff has made no arguments opposing monthly billing costs included in OM&A in section 7.1 of its submission.

10.2 Are Toronto Hydro's proposals for the disposition of balances in existing deferral and variance accounts and other amounts appropriate (Issue 8.2)?

Toronto Hydro is seeking disposition of its audited December 31, 2018 Group 1 deferral and variance account (DVA) balances, its audited December 31, 2018 Group 2 DVA balances, plus forecast 2019 principal activity for certain Group 2 DVAs, and "Other Amounts".[534]

Toronto Hydro has confirmed that it has followed the guidance provided in the OEB's *Report on Electricity Distributors' Deferral and Variance Account Review*[535] and the OEB's Chapter 2 Filing Requirements[536] with respect to its DVA balances. It further confirmed that the December 31, 2018 component of the above DVA balances reconciles to its December 31, 2018 RRR filing and audited financial statements, except where accounts have been adjusted during this proceeding. Interest on the principal portion of the DVA balances was calculated using the OEB's prescribed quarterly interest rates.[537]

OEB staff submits that the Group 1 DVA balances can be disposed as filed by Toronto

[533] Argument-in-Chief / p. 70.
[534] Other Amounts represent balances that have accumulated but for which Toronto Hydro did not previously request OEB approval to establish a DVA to capture these balances. Toronto Hydro is seeking disposition of these Other Amounts as part of its current application.
[535] EB-2008-0046.
[536] OEB Chapter 2 Filing Requirements for Cost of Service / July 12, 2018 / p. 60.
[537] The prescribed interest rates for Q3 and Q4 will need to be updated at the draft rate order stage of the proceeding as they are currently based on a forecast.

Hydro. OEB staff also submits that the Group 2 DVA balances and Other Amounts can be disposed as proposed by Toronto Hydro with a few exceptions. Specifically, OEB staff submits that the forecast 2019 principal activity should not be disposed, and the $17.2 million balance in the Impact for USGAAP deferral account should also not be disposed. The impact of this submission on the proposed Group 2 DVA balances and other amounts disposition is a reduction to the credit balance (refund) for 2020 of $47.4 million.[538] However, OEB staff is proposing that the audited 2019 Group 2 DVA principal activity be returned to ratepayers as part of the 2021 Custom IR update application. The 2019 Group 2 DVA balances are currently forecast to be a credit of $64.6 million.

Group 1 DVA Balances

The proposed Group 1 DVA balances for disposition are set out in the table below. [539]

Table 31
Group 1 DVA Balances at December 31, 2018

USofA Account #	Account Description	Principal Balance ($M)	Interest Balance ($M)	Total Disposition Amount ($M)
1550	LV Variance Account	$0.3	$0.0	$0.3
1551	Smart Metering Entity Charge Variance Account	($0.7)	($0.0)	($0.7)
1580	RSVA - Wholesale Market Service Charge	($4.8)	($0.2)	($5.0)
1584	RSVA - Retail Transmission Network Charge	$8.9	$0.3	$9.2
1586	RSVA - Retail Transmission Connection Charge	$17.4	$0.5	$17.9
1588	RSVA - Power	($5.4)	($0.2)	($5.6)
1589	RSVA - Global Adjustment	($23.9)	($0.4)	($24.3)
	TOTAL GROUP 1	**($8.2)**	**$0.0**	**($8.2)**

Toronto Hydro is seeking disposition of its December 31, 2018 audited Group 1 DVA balances over a 1-year period.

538 This is calculated as a $64.6 million reduction to the credit balance related to the removal of the 2019 forecast principal activity, offset by the removal of the 2018 debit balance of $17.2 million in the Impact for US GAAP deferral account.
539 Exhibit U / Tab 9 / Schedule 1 / p. 1; and U-Staff-190 / Appendix A.

OEB staff submits that it has no concerns with the disposition, on an interim basis,[540] of the audited December 31, 2018 Group 1 DVA balances of approximately $8.2 million (refund to ratepayers) as presented in the table above over a 1-year period.[541]

Toronto Hydro is not proposing to dispose of its 2018 LRAMVA balance as part of the current proceeding and expects to bring that balance forward for disposition as part of a future application.[542] Although the LRAMVA is required to be disposed of as part of a utility's cost-based rate application, OEB staff notes that Toronto Hydro's proposal to defer disposition of this account can be accommodated on the basis of OEB staff's proposal that the 2019 audited Group 2 DVA balances be brought forward for disposition as part of Toronto Hydro's 2021 Custom IR update application. Therefore, the audited 2019 LRAMVA balance can be considered for disposition as part of that application, which is not expected to be a mechanistic Custom IR application in any event (due to the disposition of Group 2 DVA balances).

Group 2 DVA Balances

The proposed Group 2 DVA balances for disposition are set out in the table below. [543]

[540] As per the July 20, 2018, OEB letter to all rate regulated licensed electricity distributors, the OEB will not be approving Group 1 rate riders on a final basis until such time as the OEB has provided new standardized guidance on the accounting for commodity pass-through variance accounts and is satisfied that this new guidance has been fully implemented across the sector.
[541] Although the OEB will be conducting an audit of Toronto Hydro's 2018 Global Adjustment related accounts (Accounts 1588 and 1589), OEB staff does not believe that this pending audit should prevent the disposition of the related 2018 DVA balances. OEB staff notes that the Group 1 DVA balances have already been subject to an external audit, are not being disposed of on a final basis (interim disposition only), and the supporting GA Analysis Workform presented an unreconciled difference that was below the allowable threshold.
[542] U-Staff-191(b).
[543] Argument-in-Chief / p. 71. OEB staff also added "Other Amounts" to the table related to the gain on sale of 50/60 Eglinton Avenue and Accounts Receivable Credits. The excess expansion deposit balance was reclassified from a Group 2 DVA balance to Other Amounts as there was no deferral account in place for this balance during the 2015-2019 Custom IR term. The Other Amounts are discussed in Exhibit 8 / Tab 1 / Schedule 1 / p. 11 and Exhibit U / Tab 9 / Schedule 1 / Appendix E.

Table 32
Group 2 DVA Balances and Other Amounts

USofA Account #	Account Description	Principal Balance Dec 2018 ($M)	Interest Balance Dec 2018[544] ($M)	2019 Projected Principal Activity ($M)	Total Disposition Amount ($M)
1508	Impact for USGAAP[545]	$17.2	$0.0		$17.2
1508	CRRVA[546]	($52.8)	($2.3)	($33.3)	($88.4)
1508	Externally Driven Capital	($2.3)	($0.1)	($0.8)	($3.2)
1508	De-recognition Costs	($21.0)	($1.4)	($12.1)	($34.5)
1508	Wireless Attachments	($0.5)	($0.0)	($0.1)	($0.6)
1508	Monthly Billing	$7.4	$0.4	$4.1	$11.9
1508	Operating Centers Consolidation	($52.8)	($1.7)	($19.0)	($73.5)
1508	OPEB Cash vs. Accrual	$5.5	$0.0	$2.6	$8.1
1555	Stranded Meters			($1.4)	($1.4)
1575	US GAAP to IFRS Transitional PP&E			($1.6)	($1.6)
	TOTAL GROUP 2	**($99.3)**	**($5.1)**	**($61.6)**	**($166.0)[547]**
OTHER AMOUNTS:					
	Excess Expansion Deposits	($7.5)	($0.5)		($8.0)
	Gain on sale 50/60 Eglington Avenue[548]	($8.4)	($0.4)	($3.0)	($11.8)

544 Includes interest on 2019 forecast principal activity. Interest on only the 2018 principal balance will differ slightly.
545 The actual December 31, 2018 audited balance in this account is $48.1 million. The $17.2 million balance presented in Table 31 represents the portion of this total balance that Toronto Hydro is seeking to recover during its Custom IR term. It is based on the employee average remaining service life (EARSL) recovery approach that Toronto Hydro has proposed in its response to U-Staff-193.
546 The $88.4 million balance in the CRRRVA reflects the inclusion of a $10.5 million credit related to the impact of the CCA change on capital-related revenue requirement in 2019 set out in response to U-Staff-188 / Table 1.
547 The $8 million variance between the $166 million shown in Table 31 and the $174 million shown at Argument-in-Chief / p. 71 is due to the reclassification of the excess expansion deposit balance as an "Other Amount."
548 Exhibit 8 / Tab 1 / Schedule 1 / p. 11. This balance relates to a gain on sale of property that was realized in 2017. Toronto Hydro had proposed to return these amounts to ratepayers. The balance was included within the disposition amount presented in Exhibit U / Tab 9 / Schedule 1 / Appendix E.

	Accounts Receivable Credits[549]	($3.3)	($0.1)		($3.4)
	TOTAL OTHER	**($19.2)**	**($1.0)**	**($3.0)**	**($23.2)**
TOTAL GROUP 2 AND OTHER AMOUNTS		**($118.5)**	**($6.1)**	**($64.6)**	**($189.2)**

Toronto Hydro is seeking disposition of its Group 2 DVA balances and other amounts over a 5-year period. Toronto Hydro has selected 5 years in order to minimize the bill impacts to all affected customers.[550]

OEB staff notes that Table 32 excludes the amounts included within account 1533 – Renewable Generation Connection Funding Adder Deferral Account, Sub-Account Provincial Rate Protection Payment Variances. This account tracks the difference between the revenue requirement associated with the REI that is funded through the Provincial Rate Protection program and collected through payments from the IESO and revenue requirement based on actual REI investments.[551] The balance in this account as at December 31, 2018 is a credit of $4.3 million, and an additional credit of $2 million is projected for 2019 (for a total expected balance of $6.3 million by the end of 2019). Although Toronto Hydro is requesting disposition of the balance in this account as part of the current proceeding, it has no impact on rates as the amount in the account is proposed to be refunded to the IESO, not ratepayers.[552]

OEB staff submits that the Group 2 DVA balances and Other Amounts can be disposed as proposed by Toronto Hydro with a few exceptions. Specifically, OEB staff submits that the forecast 2019 principal activity should not be disposed, and the $17.2 million balance in the Impact for USGAAP deferral account should also not be disposed.

OEB staff also has no concerns with Toronto Hydro's proposed allocators for its Group 2 DVAs and Other Amounts.[553]

However, it was not included within the proposed disposition amounts presented in the Argument-in-Chief / p. 71.

549 The accounts receivable credits classified as an Other Amount is discussed in the Argument-in-Chief / p. 71.

550 Exhibit 9 / Tab 1 / Schedule 1 / p. 40.

551 Exhibit 9 / Tab 1 / Schedule 1 / pp. 34-35.

552 Exhibit U / Tab 9 / Schedule 1 / p. 2.

553 9-Staff-161.

Disposition of Projected 2019 Principal Activity in the Group 2 DVAs

As shown in Table 32, Toronto Hydro is proposing to include projected principal activity for 2019 of approximately $64.6 million (refund to ratepayers) as part of its requested disposition amount.[554] Toronto Hydro made this request on the basis that it provides ratepayers with immediate and full benefit of the proposed distribution rate reduction, it enhances regulatory efficiency by eliminating the need for a process to examine and clear the 2019 principal activity, and will protect customers with respect to any variances.[555]

The OEB's stated policy is to dispose of audited DVA balances only.[556] Although exceptions to this rule have been made in the past, OEB staff submits that an exception should not be made as part of the current proceeding. Instead, OEB staff submits that the 2018 audited DVA balances should be disposed of as part of the current proceeding (over a 5-year period) and the 2019 Group 2 DVA activity, which will be audited in 2020, should be brought forward for disposition as part of Toronto Hydro's 2021 Custom IR update application (and be disposed over a 4-year period). In OEB staff's view, ratepayers will benefit from this approach because it results in improved rate smoothing over the 2020-2024 Custom IR term compared to Toronto Hydro's current proposal.[557] OEB staff notes that this proposal will require additional review as part of the 2021 Custom IR update application as typically Group 2 DVA balances are only disposed as part of rebasing applications. However, OEB staff submits that the incremental work that will be required as part of the 2021 Custom IR update proceeding to review and dispose of the 2019 Group 2 DVA activity is not a sufficient reason to dispose of the forecast activity now. OEB staff is of the view that the benefits (i.e. disposing of audited balances and rate smoothing) outweigh the costs (i.e. additional review in the 2021 Custom IR update application).

554 U-Staff-191 revised for U-Staff-188 and U-Staff-190 / Appendix B.

555 Argument-in-Chief / pp. 72-73.

556 OEB Chapter 2 Filing Requirements for Cost of Service / July 12, 2018 / p. 64.

557 Undertaking J8.8. Toronto Hydro was asked to prepare the bill impacts under a scenario where only the 2018 audited balances are disposed of in the current proceeding (over 5 years) and the audited 2019 balances are disposed of in the 2021 Custom IR update application over the remaining 4 years of the Custom IR term. This scenario results in higher bill impacts for 2020 (i.e. a smaller decrease in rates for 2020) and lower bill impacts in 2021 (i.e. a smaller increase in rates for 2021) compared to Toronto Hydro's current proposal. For the remaining years in the Custom IR term (2022-2024), the monthly bill impacts remain unchanged compared to Toronto Hydro's current proposal. For reference, the bill impacts under Toronto Hydro's current proposal can be found in Undertaking J7.4 and the bill impacts associated with OEB staff's proposal can be found in undertaking J8.8. OEB staff notes that the bill impacts referenced do not reflect the updates shown in Undertaking J1.2, which operate to reduce the overall bill impacts (in both scenarios).

Other Amounts

As noted in Table 32, Toronto Hydro requested approval to refund balances to ratepayers that OEB staff has characterized as “Other Amounts” because Toronto Hydro does not have OEB-approved DVAs to capture the balances. Specifically, Toronto Hydro is seeking to refund to ratepayers a total of $23.2 million as a result of excess expansion deposits realized during the period 2016-2019, a gain on sale of property that was realized in 2017, and historical accounts receivable credits relating to the period 1997 to 2011 that Toronto Hydro was unable to return to customers.[558] In the case of the expansion deposits, section 3.2.23 of the DSC[559] provides that a utility does not have an obligation to return any remaining portions of the expansion deposit to the customer beyond the Customer Connection Horizon, however, Toronto Hydro still proposed to do so.[560]

OEB staff notes that disposition of a regulatory balance without an approved deferral account is contrary to standard regulatory procedure. A utility is required to request approval to establish a new deferral account in advance of the occurrence of the related transaction.

However, by proposing to refund these credit balances, Toronto Hydro is acting in the best interests of its ratepayers and should be recognized for doing so. OEB staff notes that it would be unfair to ratepayers to deny them of amounts that a utility seeks to refund in an application due to the absence of approved regulatory accounts, which is something that is ultimately out of ratepayers’ control. As such, OEB staff submits that the OEB should approve disposition of the Other Amounts noted above. OEB staff further submits that the disposition amounts approved should be limited to the 2018 balances.

For both the expansion deposits and the gain on sale of property, each of the 2018 balances agree to Toronto Hydro’s 2018 audited financial statements. The amounts were included within the audited regulatory balances for 2018 even though there was no approved DVA.[561] With respect to the accounts receivable credits, although the balance cannot be agreed to the 2018 audited financial statements, OEB staff accepts this

[558]Exhibit 8 / Tab 1 / Schedule 1 / p. 11; and Exhibit U / Tab 9 / Schedule 1 / Appendix E.
[559] OEB Distribution System Code / pp. 63-64.
[560] Exhibit 9 / Tab 1 / Schedule 1 / p. 41.
[561] U-Staff-192.

balance on the basis of materiality and the related evidence that was submitted on the record.[562]

For the portion of the gain on sale on property that relates to 2019 ($3 million)[563], OEB staff submits it can be brought forward for disposition with the 2019 audited Group 2 balances as part of Toronto Hydro's 2021 Custom IR update application.

Impact for USGAAP Deferral Account

Toronto Hydro is also seeking to dispose of account 1508 Impact for USGAAP. This account captures actuarial gains and losses realized on Toronto Hydro's OPEB costs.[564] Under IFRS, these gains and losses are presented as a component of other comprehensive income (in equity) and therefore never enter rates (as they never form part of the OPEB costs that are recognized as an expense in the income statement). As a result, some utilities sought approval to establish a deferral account to capture these actuarial gains and losses.[565]

In the OEB Pension and OPEB Report, the OEB addresses its expectation with respect to utilities who have been tracking balances within this account:

> Utilities may propose disposition of the account in future cost based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time.[566]

As part of the original evidence filed in this proceeding, Toronto Hydro was seeking disposition of a balance of $85.3 million in this account to be recovered over the term of this application. In support of its request to dispose of this account balance, Toronto Hydro provided extensive analysis as to why it believed that any changes in the underlying actuarial assumptions, in particular changes in the discount rate, are not expected to offset the actuarial loss incurred to date and therefore disposition of the DVA balance was justified in light of the statements made by the OEB in the OEB Pension and OPEB Report.[567]

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[562] Exhibit 8 / Tab 1 / Schedule 1 / p. 11.
[563] U-Staff-190 / Appendix B.
[564] Exhibit 9 / Tab 1 / Schedule 1 / p. 7.
[565] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 13. Seven utilities have received OEB approval to establish this type of account. Only one utility has since disposed of this account balance, which was done through a settlement agreement.
[566] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 13.
[567] Exhibit 9 / Tab 1 / Schedule 1 / pp. 7-10.

On April 30, 2019, Toronto Hydro filed an update to its pre-filed evidence. The changes included an update to DVA balances in order to reflect the December 31, 2018 audit by Toronto Hydro's external auditors. As a result of the update, the balance in this DVA declined significantly from the initial $85.3 million to $48.1 million (a reduction of $37.2 million). This decline stemmed from an updated OPEB actuarial valuation that was done as of December 31, 2018 and resulted in the recognition of an actuarial gain of $37.2 that was recorded against the DVA balance.[568]

In response to interrogatories on the updated evidence, Toronto Hydro further amended its disposition request related to this account. Rather than seeking the immediate disposition of the entire account balance over the 2020-2024 Custom IR term, it proposed to use an alternate disposition methodology known as the employee average remaining service life (EARSL) method.[569] Under this approach, the account balance is amortized to rates over the employee average remaining service life of 14-years. This results in a total disposition of $17.2 million over the Custom IR term, or $3.44 million per year. Toronto Hydro is proposing that the EARSL method continue to underpin the disposition of the DVA balance for future rate applications.[570]

OEB staff submits that the balance in this account should not be disposed of at this time. OEB staff notes that the significant decline in the account balance ($85.3 million to $48.1 million) as a result of the recent OPEB actuarial valuation supports OEB staff's position (and the position set out in the OEB Pension and OPEB Report) that there is a recognition that the balance in this account may substantively offset over-time. Given the significant movement in the account balance that can occur as a result of one actuarial valuation, it would be premature to conclude otherwise.

As noted previously, Toronto Hydro provided an extensive analysis in support of its disposition request for this account, and in particular, why it believed that the balance in this account would not substantially offset over time. This analysis considered the impact that the expected future discount rate could have on the balance accumulated within this account and concluded that disposition of the account balance at this time is appropriate because the discount rate used to value the OPEB obligation is not expected to fluctuate significantly enough to offset the actuarial losses incurred in the account to date.[571] Toronto Hydro's analysis did not address the impact that the

[568] Exhibit U / Tab 9 / Schedule 1 / pp. 2, 4.
[569] U-Staff-193.
[570] U-Staff-193 / pp. 2-5.
[571] Exhibit 9 / Tab 1 / Schedule 1 / pp. 7-10.

changes / fluctuations in the other actuarial assumptions, such as mortality rates and demographics, could have on the actuarial losses accumulated to date.[572] Toronto Hydro further indicated that it considers changes in the discount rate to be the actuarial assumption that could have the most significant impact on the balance accumulated in this account.[573]

Toronto Hydro has not provided any information as to how much of the $37.2 million gain is actually attributed to a fluctuation in the discount rate. However, in OEB staff's view (and confirmed by Toronto Hydro), it is reasonable to conclude that most of the gain can be attributed to the discount rate since it is viewed as the most significant assumption that underpins an actuarial valuation and therefore could have the most significant impact on the balance accumulated within this account. As such, OEB staff also submits that the significant decline in the account balance as a result of the December 31, 2018 OPEB valuation contradicts the discount rate analysis completed by Toronto Hydro in support of its disposition request.[574]

OEB staff further submits that the disposition of the balance within this account can be revisited as part of Toronto Hydro's next rebasing application.

Toronto Hydro also indicated that for financial statement reporting purposes, a regulatory asset can only be recognized in its financial statements if it is probable that the deferred cost will be recovered in future rates. Toronto Hydro argued that if there is no acceptance by its regulator for the subsequent inclusion of this deferred balance in its rates, it may result in an impairment of the balance for financial statement reporting purposes.[575] OEB staff is of the view that given the significant movement in the account balance as a result of the recent actuarial valuation, Toronto Hydro's auditors may not be opposed to the continued recognition of this account balance on the balance sheet for the near term with an acknowledgement by the regulator that the account balance will be revisited as part of Toronto Hydro's next scheduled cost-based application.

Alternatively, if the OEB sees merit in Toronto Hydro's arguments to dispose of this account balance starting in 2020, OEB staff submits that the disposition methodology should be based on the corridor approach instead of the EARSL method that Toronto Hydro has now proposed.

[572] 9-Staff-152 (i).
[573] 9-Staff-152 (i).
[574] Exhibit 9 / Tab 1 / Schedule 1 / pp. 7-10.
[575] U-Staff-193.

OEB staff had requested that Toronto Hydro investigate two disposition methodologies for regulatory purposes, the corridor approach and the EARSL method.[576] Under the corridor approach, actuarial gains and losses—to the extent that they fall outside a corridor of 10% of the higher of the plan asset or liability value—would get amortized to rates over a period not exceeding EARSL. Based on the calculations provided by Toronto Hydro, this methodology would result in the recovery of approximately $6.4 million of the DVA balance over the 2020-2024 plan period.[577]

OEB staff submits that the use of corridor approach is appropriate for purposes of recovering the balance in the Impact for USGAAP deferral account on the basis that:

- It is consistent with how Toronto Hydro previously recognized these costs when the balance in this account was being amortized into rates under USGAAP.[578]
- It provides for a greater opportunity for the gains and losses tracked in the account to offset overtime, but also recognizes that amounts should be disposed of from the account when the balance grows too large.[579]
- It will satisfy any concerns related to the continued presentation of this balance as a regulatory asset (as noted above) as it allows for the recovery of the account balance through rates.

Toronto Hydro refers to the corridor approach as “hypothetical” as it is no longer a valid approach for recognizing actuarial gains and losses into profit under IFRS.[580] OEB staff notes that the EARSL method that is being proposed by Toronto Hydro in this application is also not a recognized approach under IFRS. The reality is neither of these approaches are recognized by IFRS because IFRS does not permit the amortization of actuarial gains and losses for financial statement purposes. Irrespective of this, the methodology that is used to recognize amounts from a regulatory asset account into rates is not a matter related to accounting and accounting standards, but rather is a decision that is at the discretion of the regulator to ensure that the resulting rates are just and reasonable.

[576] Undertaking JTC4.10.
[577] Undertaking JTC4.10.
[578] Technical Conference Transcripts / Vol. 4 / p. 60.
[579] Amounts can only be disposed (amortized) if the balance of the gains and losses tracked in the account exceed the calculated corridor, which essentially acts as a threshold, and the calculation is revisited annually. Therefore, in years where this threshold is not exceeded, no amount is recognized into rates. Whereas, Toronto Hydro’s proposed approach guarantees that an amount is recognized into rates annually.
[580] JTC4.10.

CRRRVA

In section 7.3, OEB staff stated that it has no concerns with the use of the CRRRVA to record the 2018 and 2019 revenue requirement impacts pertaining to the CCA rule changes. However, if for some reason the large credit that is currently forecast in the CRRRVA for 2019 does not materialize (i.e. the account ends in a debit) and thereby offsets any refund to ratepayers related to the 2019 revenue requirement impact of the new CCA rules, in accordance with the OEB's July 25th, 2019 letter[581], OEB staff submits that the amounts pertaining to the 2019 revenue requirement impact of the new CCA rule changes should be moved from the CRRRVA and into the new sub-account of 1592.

Earnings Sharing Mechanism Deferral Account

OEB staff submits that the balance in the ESM for the 2015-2018 period was calculated correctly[582] in accordance with the OEB's decision in Toronto Hydro's 2015-2019 Custom IR proceeding.[583] The result of those calculations is that there are no earnings to be shared with ratepayers for that period. The 2019 ESM calculation should be brought forward as part of Toronto Hydro's 2021 Custom IR update application, along with the other Group 2 balances for 2019. However, OEB staff submits that the methodology for calculating the amount to be shared with ratepayers should be changed for the 2020-2024 Custom IR term. This is discussed in section 4.1 and section 10.3.

10.3 Are Toronto Hydro's proposals for the establishment of new accounts, closing of existing accounts or continuation of existing accounts appropriate (Issue 8.3)?

New Accounts

Toronto Hydro has proposed to establish the following new DVAs:

- Excess Expansion Deposits variance account

[581] OEB Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance / July 25, 2019.
[582] Exhibit U / Tab 9 / Schedule 1 / p. 14.
[583] EB-2014-0116 / Decision and Order / December 29, 2015 / p. 49.

- Account 1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account[584]

OEB staff has no concerns with the establishment of the Excess Expansion Deposits variance account[585] and notes that Account 1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account is already established on a generic basis for all distributors. However, a change to the methodology for calculating the balance in Account 1522 is being proposed. OEB staff also submits that the Carillion Insolvency Payments Receivable Account should also be established.

Account 1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account

This account will track the differences between the forecast accrual amounts recovered in rates and the actual cash payments made for Toronto Hydro's OPEB costs. It will provide ratepayers with an asymmetrical carrying charge on the cumulative differential balance in the account when the cumulative forecast accrual amount exceeds cash payments (i.e. the tracking account is in a credit position).[586] In Toronto Hydro's case, the account only relates to its OPEB costs because it is part of the OMERS pension plan.[587]

OEB staff notes that Toronto Hydro's request to establish Account 1522 Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account (and related sub-accounts) is not required. This account was already established on a generic basis.[588] Therefore, the OEB is not required to approve the establishment of this account as part of rate applications.

[584] Note that this account is different from Toronto Hydro's OPEB Cash vs. Accrual variance account that is currently in operation. The OPEB Cash vs. Accrual account was approved in the 2015-2019 Custom IR proceeding (EB-2014-0116) when Toronto Hydro was ordered to recover OPEB costs on a cash basis as an interim measure pending the completion of the OEB's generic consultation on the recovery of pension and OPEB costs. Later in this section, OEB staff proposes that the existing OPEB Cash vs. Accrual account can be closed after its final disposition in the 2021 Custom IR update application.
[585] OEB staff notes that there is an "Other Amount" of $8 million related to excess expansion deposits for the historical period (as there was no deferral account in place).
[586] Exhibit 9 / Tab 1 / Schedule 1 / pp. 42-43.
[587] Since OMERS is a multi-employer pension plan, the accrual expense equals the cash contributions that are made to the plan and therefore there is no difference between cash and accrual to track.
[588] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 20.

However, Toronto Hydro is also seeking OEB approval to use an alternate approach with respect to determining the forecast accrual amount in rates compared to the default methodology that is prescribed in the OEB Pension and OPEB Report.

The default methodology 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 Pension and OPEB 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).[589]

As Toronto Hydro capitalizes a significant portion of its OPEB costs, it is proposing an alternate methodology that determines the forecast accrual amount in rates as the sum of the OM&A expense portion of its forecast annual OPEB accrual cost and the cumulative depreciation on its OPEB costs that are capitalized starting in 2020.[590]

OEB staff submits that an alternate approach for determining the forecast accrual amount in rates is not warranted in this case as the associated dollars are not material enough to justify the added complexity that an alternate methodology will introduce to the regulatory process.[591]

Using the forecast numbers provided by Toronto Hydro[592], OEB staff roughly calculated the expected carrying charges that would be payable to ratepayers over the 2020-2024 application term based on both the default methodology and Toronto Hydro's proposed alternate methodology.

[589] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / p. 20.
[590] U-Staff-196 / p. 4.
[591] Through the requirement to track separately the depreciation expense on capitalized OPEB costs and the difficulty associated with assessing the prudence and reasonability of such a balance.
[592] U-Staff-196 / Table 2.

Table 33
Comparison of Default versus Toronto Hydro Alternative Proposed Method for Account 1522 - Pension and OPEB Forecast Accrual versus Actual Cash Payments Differential Tracking Account [593]

($M)	**2020**	**2021**	**2022**	**2023**	**2024**
Default Approach:					
Gross Accrual OPEB cost **A**	$ 13.30	$ 13.60	$ 13.90	$ 14.10	$ 14.40
Actual cash payments **B**	$ 9.20	$ 9.70	$ 10.20	$ 10.60	$ 11.00
Differential = **A + B = C**	$ 4.10	$ 3.90	$ 3.70	$ 3.50	$ 3.40
Cumulative differential to date	$ 4.10	$ 8.00	$ 11.70	$ 15.20	$ 18.60
Total interest @ CWIP = **C x 2.88%**	$ 0.12	$ 0.23	$ 0.34	$ 0.44	$ 0.54
Toronto Hydro Alternate Approach:					
Total interest	$ -	$ -	$ -	$ -	$ -

OEB staff notes that under the alternate methodology, Toronto Hydro is not expected to refund any amounts related to the carrying charges on the cumulative differential in the account because the accrual amount recovered in rates does not exceed the cash payments made.[594] OEB staff further notes that under the default methodology set out in the OEB Pension and OPEB Report, the related carrying charges are also expected to be insignificant. Based on the calculations above, and consistent with the requirements of the OEB Pension and OPEB Report, the proposed alternate methodology does not provide sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately from those that are expensed.

However, if the OEB determines that an alternate approach is warranted, OEB staff submits that Toronto Hydro's proposed alternate methodology understates the accrual amount that is being recovered in rates as it only considers the depreciation associated with the OPEB costs that have been capitalized since 2020.

The focus of the OEB Pension and OPEB Report was to provide ratepayers with a return on money they have effectively lent a utility in a given rate year when the OPEB

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[593] Derived from U-Staff-196 / Table 2.

[594] Refer to Table 2 of the response to U-Staff-196 for the actual calculation of the annual differential between forecast accrual and actual cash as calculated under Toronto Hydro's proposed alternate approach. Since the cash payments will exceed the accrual cost in each year, in accordance with the OEB Report, no carrying charges on the differential will apply.

amounts collected in rates exceed the utility's actual cash requirements.[595] In a given rate year, Toronto Hydro will not only recover the depreciation associated with the OPEB costs it has capitalized since 2020, but instead recovers the deprecation associated with the total OPEB costs that it has capitalized to date. Therefore, Toronto Hydro's alternate methodology is proposing to ignore a portion of the OPEB amounts that it is collecting in rates. OEB staff submits that such an outcome is not consistent with the spirit of the OEB Pension and OPEB Report.

OEB staff further submits that if an alternate methodology is approved by the OEB, the calculation of the forecast accrual amount should instead be based on the total cumulative depreciation of OPEB costs that have been recognized in the rates of a given year.

Carillion Insolvency Payments Receivable Account

As discussed in section 5.1, OEB staff submits that the Carillion Insolvency Payments Receivable account should be established to record the revenue requirement impact of any payment received related to the ongoing Carillion insolvency litigation.

Continuation of Existing Accounts

Toronto Hydro proposed to continue or discontinue its existing DVAs as set out in the following table.[596]

Table 34
Proposed Continuation and Closure of Existing Group 2 DVAs

Group 2 DVAs	Proposed Status
Stranded meter costs	Close
IFRS USGAAP Transitional PP&E amounts	Close
Impact for USGAAP Deferral	Open
Capital Related Revenue Requirement (CRRRVA)	Open
Externally Initiated Capital (EIP)	Open
Derecognition	Open

[595] OEB Report on the Regulatory Treatment of Pension and OPEB Costs / September 14, 2017 / pp. 10-11.
[596] Undertaking JTC4.7. OEB staff removed the Excess Expansion Deposit deferral account from the table as it was not in place during the 2015-2019 period (and therefore, cannot be described to continue in the 2020-2024 Custom IR term). OEB staff also updated the status of the OPEB Cash vs. Accrual variance account to close based on the Argument-in-Chief / p. 77.

Wireless Attachments	Open
Monthly Billing	Close
Operating Centers Consolidation Program (OCCP)	Close
Other Post-Employment Benefits (OPEB) Cash vs Accrual	Close
Renewable Generation Connection Funding Adder Deferral Account	Open

OEB staff has no concerns with respect to the accounts proposed for continuation, except for the ESM deferral account and the Derecognition variance account. OEB staff notes that the ESM deferral account is not listed in Table 34 but that Toronto Hydro has sought approval to continue the ESM deferral account using the same methodology that was previously approved by the OEB.[597]

Earnings Sharing Mechanism Deferral Account

OEB staff agrees that the ESM should continue as part of the 2020-2024 Custom IR term. However, as discussed in section 4.1, OEB staff submits that the methodology used to calculate the earnings sharing should be amended.

OEB staff notes that the current methodology is not actually designed to share earnings but rather is a symmetrical true-up of annual non capital-related revenue requirement, as was acknowledged by Toronto Hydro during the oral hearing.[598] Under the current approved ESM methodology, if Toronto Hydro overspent on its OM&A it would be entitled to recover some of that balance through the ESM (provided the dead band of 100 basis points on the ESM is breached).

OEB staff submits that following further review of the Custom IR framework and the current ESM methodology, it is apparent that the methodology does not sufficiently incentivize the utility to spend on a prudent basis. OEB staff further submits that the current ESM methodology does not protect ratepayers against fluctuations in the load and customer forecasts that underpin the revenue requirement. The development of such forecasts are outside of the control of ratepayers and therefore they should be protected against fluctuations in these amounts.

OEB staff proposes a methodology for the ESM that is based on the OEB's annual RRR 2.1.5.6 filing, which compares the ROE approved in rates with the actual ROE achieved

[597] Exhibit 1B / Tab 1 / Schedule 1 / p. 13.
[598] Oral Hearing Transcripts / Vol. 6 / p. 152.

and uses regulatory net income as the starting point. This approach is consistent with the ESM methodology approved in other rate applications.[599]

OEB staff understands that under its proposed approach, certain adjustments may be required to the calculation in order to account for amounts within the actual ROE achieved that were not contemplated within the approved ROE in rates. Such adjustments can be proposed and handled on a case-by-case basis when the ESM is brought forward for disposition.[600]

OEB staff further submits that its approach to the ESM minimizes regulatory burden because it is based on a calculation that the utility will already be performing on an annual basis as part of its RRR fillings.

OEB staff submits that the ESM should continue to include a 100 basis point dead band. However, the account should be non-cumulative (as explained earlier in this submission) and asymmetrical in favour of ratepayers. Therefore, earnings are only shared (50% to the benefit of ratepayers) if the actual ROE achieved in a given year exceeds the ROE approved in rates by at least 100 basis points.

OEB staff submits that the earnings sharing calculation should be performed for each year of the Custom IR term in accordance with the methodology discussed above. Therefore, entries to record amounts to the ESM account would only be made in years that Toronto Hydro has over earned in excess of the 100 basis point deadband. However, the filing of the annual ESM calculations and the request for disposition (if there are earnings to be shared with ratepayers) should be made at the time of the next rebasing application. This will avoid a potentially complex review of the ESM calculation as part of the Custom IR update applications.

Derecognition Variance Account

As discussed in section 7.2, OEB staff submits that Toronto Hydro should be required to cease recording balances in the derecognition account beginning in 2020 (and the

[599] A similar ESM methodology was used in Horizon's 2015-2019 Custom IR (EB-2014-0002) and was also used in Hydro Ottawa's 2016-2020 Custom IR application (EB-2015-0004).
[600] These adjustments will change each year and, therefore, OEB staff cannot provide a position on the appropriateness of any specific adjustment to net income that will occur over the 2020-2024 period at this time.

account should be closed after the disposition of the 2019 balance in the 2021 Custom IR update application).

Discontinuance of Existing Accounts

OEB staff submits that no accounts should be closed as part of the current proceeding.

In section 10.2, OEB staff submitted that the disposition of the projected 2019 principal activity related to Group 2 DVAs should be deferred until Toronto Hydro’s 2021 Custom IR update application. Therefore, it would be inappropriate to close any of the accounts listed in Table 34 at this time as they currently contain balances that will form part of the disposition request in the 2021 Custom IR update application.

If the OEB approves the disposition of the projected 2019 Group 2 DVA principal activity as part of the current proceeding, OEB staff submits that the accounts listed in Table 34, should still not be closed at this time. Given that the 2019 principal activity is based on projections, OEB staff submits that the related accounts should remain open in order to capture the difference between these projections and actual. The residual balances tracked in these accounts should then be brought forward for disposition as part of the 2021 Custom IR update application.

OEB staff submits that, while no accounts should be closed as part of the current proceeding, it supports the closure of the following accounts after the 2019 audited balances are disposed of as part of the 2021 Custom IR update application (and notes that these accounts should not record any 2020 principal activity):

- Stranded Meter Costs deferral account
- IFRS USGAAP Transitional PP&E Amounts deferral account
- Derecognition variance account
- Monthly Billing variance account
- Operating Centres Consolidation Program deferral account
- OPEB Cash vs. Accrual variance account

- All of which is respectfully submitted -