EB-2019-0082
Hydro One Networks Inc. Compendium
Panel 5 - Pacific Economics Group

November 4, 2019

TAB 1

M1-HON-6

Reference: Exhibit M1, page 22

Preamble:

PEG states that the “short sample period” of PSE unnecessarily reduces the precision of the econometric model parameter estimates. PEG also states that the sample period produces an “inappropriately negative value” for the trend variable parameter.

Interrogatories:

a) Given PEG’s concerns for a longer sample period and the availability of the data, why did PEG not add the years 2017 and 2018 to the data sample?

b) Did PEG conduct any preliminary work to update the dataset to 2017 and/or 2018? If so, please provide any preliminary results of that work.

c) In the recent Toronto Hydro proceeding, PEG updated its research to 2017 (all the 2018 data was not yet available but is now). In this Hydro One proceeding, PEG has made a special point about the importance of a longer sample period. Given PEG’s concern over a short sample period, please update PEG’s MFP and total cost benchmarking study samples to and including 2018. Please revise Table 2, 3, and 5 of the PEG Report accordingly.

d) Both PSE and PEG find the industry has negative productivity trends over the time periods used (2005 to 2016 for PSE, 1996 to 2016 for PEG). PEG finds the industry from 1996 to 2016 has negative productivity growth of -0.25%. However, in PEG’s econometric total cost model the trend parameter estimate in the current report is -0.006 (see Table 2 on p. 33 of Exhibit M1). This implies, all else equal, a positive productivity trend over this period of 0.6%. Is PEG concerned that its econometric model trend parameter is not consistent with its own productivity trend research? Please explain and discuss why PEG believes this discrepancy exists.

e) Please confirm that PEG’s own research indicates that the transmission industry has had negative productivity growth for the ten most recent years of the sample.

f) Please confirm that out of the last eight years, all years but one had productivity declines lower than -1.00%. In the one year that had the highest productivity growth the growth rate was still -0.66%. However, PEG's model has a trend estimate showing a 0.6% productivity improvement in each year, all else equal. On what basis does PEG think +0.6% is a reasonable estimate of the productivity trend in the forecasted years of 2020 to 2022?

g) Does PEG's benchmark for Hydro One in the forecasted years assume a +0.6% annual productivity improvement?

h) Given PEG's concern over this issue, please re-run the PEG model and add a quadratic trend variable to the model (Trend*Trend). Please provide a revised Table 2 and Table 5 showing the benchmarking model and results.

Response to HON-6: The following response was provided by PEG.

a) At the start of the HOSSM project in late 2018, the requisite transmission operating data for 2018 were unavailable and PEG had not processed the 2017 transmission data, whereas PEG had already gathered these data for earlier years back to 1995. In their proposal to OEB Staff for the HOSSM project, PEG did not include a data update (as PSE had similarly not done a data update for its new evidence) and no budget for such work was provided. For the Hydro One Transmission proceeding, OEB Staff asked PEG to focus mainly on the C factor issue and to limit the expenditure of effort on upgrades and updates to their Hydro One SSM statistical cost research, consistent with the limited updates that PSE had done. PSE also had an opportunity to add additional years of data to its study but did not do so.

b) PEG used 2017 distributor operating data in its cost research for OEB Staff in the recent Toronto Hydro proceeding. However, they have not incorporated 2017 transmission data into their transmission work. Any work by PEG to gather 2018 data has been highly preliminary, not focussed on transmission, and has not been funded by any PEG client.

c) This analysis would require obtaining all of the necessary data for 2018, conducting necessary exploratory data analysis to assess the quality and consistency of the data, and then to update the analyses which PEG has documented in its evidence. PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding.

d) Trend variable parameter estimates can vary from MFP trends because econometric models have different output specifications and include time-variant Z variables. PSE's trend variable parameter estimate of 0.012 compares to an industry MFP trend of -1.45% for the full sample period. The difference is a non-negligible 33 basis points. PEG, like PSE, used data for the econometric work in this proceeding from a substantially larger group of companies than they did for the productivity work because the econometric research does not require *panel* data (a full set of annual observations for each company). Note also that PEG reported productivity results for a *cost-weighted* average of the sampled U.S. utilities whereas the econometric work effectively applies the *same weight* to data from all sampled companies.

e) This statement is confirmed.

f) The +0.60 trend parameter estimate is less sensitive to the special operating conditions of the 2005-2016 period and was rendered more precise by the larger sample period employed in its estimation. Its positive value may indicate that the MFP trend for a larger sample of utilities would be more positive than the trend for the smaller samples used in the MFP research due to data limitations. The productivity trend of sampled utilities has been negative since 2005, but the degree to which this has been due to cost drivers that are relevant to Hydro One is unclear.

g) No. But the 0.60 value of the trend variable is used in the projection.

h) PEG believes that PSE can perform the requested run. While the addition of a quadratic term to the model could slow the Company's cost growth projections, it is not clear whether this is due to cost drivers similar to those facing Hydro One.

HYDRO ONE INTERROGATORIES ON THE PACIFIC ECONOMICS GROUP REPORT

M1-HON-1

Reference: Exhibit M1, Page 38

Preamble:

In docket EB-2018-0218 (the "HOSSM Case" or simply "HOSSM"), Pacific Economics Group ("PEG") corrected certain errors discovered by PSE in PEG's response to interrogatory PEG-HOSSM-6i. In an attachment labeled "Attachment PEG-HOSSM-6i(b)" to that response, PEG displayed a table showing that Hydro One's 2014-2016 average total cost score was -22.87%, and that its 2019-2022 average total cost score was -12.35%. Below is the table produced by PEG in the HOSSM Case.

Attachment PEG-HOSSM-6i(b)

Hydro One's Total Transmission Cost Performance Using PEG's Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-41.20%
2005	-44.20%
2006	-43.30%
2007	-38.50%
2008	-41.00%
2009	-34.70%
2010	-32.40%
2011	-31.80%
2012	-27.90%
2013	-25.30%
2014	-25.00%
2015	-21.60%
2016	-22.00%
2017	-20.50%
2018	-18.70%
2019	-16.40%
2020	-13.70%
2021	-11.00%
2022	-8.30%
Average 2004-2016	**-32.99%**
Average 2014-2016	**-22.87%**
Average 2019-2022	**-12.35%**

[1] Formula for benchmark comparison is $\ln(Cost^{HOSSM}/Cost^{Bench})$.

However, in the present case (the "Hydro One Networks Case"), in Table 5 on p. 38 of Exhibit M1 (the "PEG Report"), we see a substantial change in PEG's benchmarking results for Hydro One Networks. PEG's results have now changed to -2.1% for the 2014-2016 period, and +9.0% for the 2020-2022 period. This amounts to a very significant change in benchmarking results from the results PEG put forth about six months ago. This change is despite the fact that in the present case, PEG apparently: (1) reduced Hydro One's costs to make the cost definitions consistent, and (2) inserted the company's revised business plan, with lower spending levels, into the model. We would expect these two cost modifications to improve Hydro One's score.

Interrogatories:

a) Given this substantial change in results, Hydro One requests that PEG itemize each modification made in the current case, relative to what PEG did in the HOSSM Case. For each modification, we request that PEG provide the impact of that modification on Hydro One's 2020 to 2022 average benchmark score.

We request the following table be filled out by PEG, although more rows should be inserted based on the methodological changes identified by PEG. PEG can begin with the model presented in Table 2 of the PEG Report and only change one modification at a time, so we can isolate the impact of each methodological change relative to their results reported in the HOSSM Case. For example, for Change #5, please start with the methodology used in the Hydro One Networks Case (the "Reported Methodology") and only perform Change #5, so we can see how the reported results would change when only Change #5 is made.

In light of the results from the completed table, please describe what PEG thinks are the drivers of the large changes from the HOSSM results to the result in the present case.

Change #	Methodological change from HOSSM	2020 – 2022 average benchmark score for HON
0	Reported Methodology	+9.0%
1	Variable changed back to substation capacity per line mile	

2	Depreciation rates changed back to HOSSM values	
3	Cost definition on OM&A changed back to HOSSM definition	
4	Revert sample back to HOSSM sample	
5	Revert to not doing an autocorrelation correction, and use the modeling procedure used in HOSSM proceeding	
6	Revert to including capital gains in capital costs and prices the same way conducted in HOSSM proceeding	
7	Use the implicit price deflator for the Ontario utilities sector the same way used in HOSSM proceeding	
8	Please insert any other changes relative to PEG's HOSSM methodology that impact results	

b) To enable a view of how much PEG's methodology changes impacted the results from six months ago, please re-run the model used in PEG-HOSSM-6i(a) and (b), with the same exact methodology and sample as used to produce PEG-HOSSM- 6i(b), but with Hydro One's revised business plan incorporated and costs subtracted out to make the cost definitions consistent. From that model re-run, please provide tables similar to those provided in Attachment PEG-HOSSM-6i(a) and PEG-HOSSM-6i(b).

Response to HON-1: The following response was provided by PEG.
PEG acknowledges that the results of the benchmarking work changed, due to a few methodological upgrades changes made, more than one might expect. In considering this outcome, it should be remembered that the business conditions facing Hydro One are in important respects atypical of those of other sampled utilities. This increases the likelihood of prediction error.

The requested analysis cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding. However, some analysis is provided below that should be helpful which is based on work undertaken during the preparation of the results presented in PEG's September report.

Change #	Methodological change from HOSSM	2020 – 2022 average benchmark score for HON
0	Reported Methodology	+9.0%
1	Do not change depreciation rates and use EOY capital stock instead of BOY	-2.4%
2	Remove correction for autocorrelation from #1	-14.1%
3	Reported SSM results after errata	-11.0%

a) The table above contains a breakout of principal reasons why the average benchmarking scores for the 2020-22 period have changed since the Hydro One SSM proceeding. Working backwards from the model presented in our September report, PEG made changes to the model to specifically reverse methodological choices that we recall affected results. The first reversal was to not change the depreciation rates and not use the beginning of year capital stock (which is the standard approach) instead of the end of year stock. This had about an 11% impact on the results. The second change was to remove the autocorrelation correction we implemented. Without this correction, results were about 12% more favorable to the Company. All other changes only affect the results by about 3% and would result in a less favorable score for HON if not done. None of these results incorporate the work done in response to HON-21 (Exhibit L1/Tab 1/Schedule 21).

   The changes examined in step 1 above were some of the last we made to the work before completing the report. PEG did additional analysis at that time to find an explanation for the result. What we found was that the business conditions facing Hydro One are atypical in several respects, and that changes in the estimated values of some coefficients had a much larger impact on the predicted cost of Hydro One than other transmitters in the sample.

   The following table shows how values of the business condition variables in PEG's model compared to those for the U.S. sample mean in 2016. A few observations are pertinent. The first is that Hydro One has a much larger operating scale than the typical U.S. transmitter.

Comparison of Hydro One Network's Business Conditions in 2016 to Full Sample Norms

Business Condition	Name from Table 1	Parameter Value	Hydro One Networks, 2016 [A]	Sample Mean, 2016 [B]	2016 HONI Values / 2016 Sample Mean [A/B]
Kilometers of transmission line	**YL**	0.492	20,949	3,472	603%
Kilometers of transmission line - Squared	**YL * YL**	0.402	438,853,072	12,056,296	3640%
Kilometers of transmission line x Ratcheted Peak Demand	**YL * D**	-0.207	565,722,892	22,483,035	2516%
Ratched maximum peak demand	**D**	0.571	27,005	6,475	417%
Ratched maximum peak demand - Squared	**D * D**	0.243	729,270,025	41,927,211	1739%
Substation capacity per substation	**MVA**	0.044	419.8	320.4	131%
Average voltage of transmission line	**VOLT**	0.063	222	179.71	123%
Construction standards index	**CS**	0.238	0.87	0.67	129%
Percent of transmission plant that is overhead	**PCTPOH**	-0.395	97%	89%	109%
Percent of transmission plant in total plant	**PCTPTX**	0.140	100%	21%	486%

The length of its transmission lines is especially large. This means that the density of its system is unusually low. The model includes a squared term for each scale variable as well as scale variable interaction term km x peak. The dispersion of Hydro One's values for these so-called "second order" terms is even larger.

The other salient difference is that Hydro One is the only company in the sample that only performs transmission service. The metric used to capture the scope of operations is the percent of plant that is transmission. This is 100% for Hydro One and any scope economies with Hydro One's distribution services have been ignored for this analysis. This compares to only 21% for the U.S. sample, making Hydro One an outlier in this regard.

The impact on the predicted value for Hydro One from a change in model parameters will be related due to the magnitude of the change and how different Hydro One is from average. From the above table, we can see that the scale, substation capacity, and scope variable are the most atypical. Therefore, changes in these parameters will have an outsized impact for Hydro One.

Below is a table with the parameters for the final model (change #0) and the model prior to the most impactful methodological changes (change #2). The quadratic and interaction scale variables and the scope variable are candidates to explain why the results changed and are in bold.

Parameter Values (excluding HON) used in Predicted Cost Calculation

	Final Model	**No Autocorrelation**		
	(A)	(B)	(A) - (B)	(A) / (B)
Intercept	12.1824	12.2394	-0.0571	99.5%
YL	0.4911	0.4916	-0.0005	99.9%
YL * YL	0.4017	0.3447	0.0570	**116.6%**
D	0.5793	0.5798	-0.0005	99.9%
D * D	0.2470	0.1510	0.0960	**163.6%**
YL * D	-0.2035	-0.1580	-0.0455	**128.8%**
MVA	0.0420	0.0298	0.0122	140.8%
VOLT	0.0656	0.1006	-0.0349	65.3%
CS	0.2492	0.2694	-0.0202	92.5%
PCTPOH	-0.3911	-0.5086	0.1175	76.9%
PCTPTX	0.1510	0.3015	-0.1505	**50.1%**
Trend	-0.0070	-0.0070	0.0000	99.4%

When taken together the positive impact on predicted cost from the increased values for the quadratic terms is mitigated by the more negative value of the interaction (YL * D) term. The principal driver of the changed result is that the cost impact attributed to scope considerations is considerably lower than before.

b) PEG believes that the response to part a) adequately explains the source of the performance difference. Please see the response to HON-21 (Exhibit L1/Tab 1/Schedule 21) for additional discussion of the impact from the revised business plan data.

M1-HON-13

Reference: Exhibit M1, pages 60-69

Preamble: PEG discusses their calculations of the supplemental stretch factor.

Interrogatories:

a) PEG recommends a supplemental stretch factor of 0.42% applied to the capital portion of the revenue requirement. Please verify that this 0.42% assumes an X-Factor of 0.0%.

b) If the X-Factor was set at the PEG recommendation of 0.05%, would PEG's recommended S-Factor be lowered to 0.37%?

c) If the X-Factor was, instead, set at the HOSSM value of 0.3%, would this lower the PEG recommendation of the S-Factor to 0.12%?

d) Did PEG consider the company's progressive productivity proposal in its plan when setting the S-Factor?

e) If the progressive productivity proposal amounts to a 0.15% stretch factor in 2021 and a 0.3% stretch factor in 2022, and the Board determines a 0.3% X-Factor, would PEG then recommend a negative S-Factor?

Response to HON-13: The following response was provided by PEG.

a) PEG acknowledges that the 0.42% S factor calculation that it proffered in its September report was based on the assumption of a zero X factor. However, a review of its calculations revealed a small error. The corrected value of the ACM-equivalent S factor which is consistent with a zero X factor is 0.31%. Table HON-13 provides S factor, C factor, and revenue cap escalator results under three X factor assumptions (0, 0.05%, and 0.3%) and compares the results to Hydro One's proposal.

b) Were the X factor set at 0.05% per PEG's recommendation, PEG believes that the ACM-equivalent S factor would be 0.26%.

Table HON-13

Impact of X Factor and S Factor Changes on HON C Factor and RCI Growth

	Index Year			Difference from HON Proposal
	2021	**2022**	**Averages**	
Variable				
Cn	5.18	4.68	4.93	
Sck	78.42	79.16	78.79	
I	1.4	1.4	1.4	
X = 0 (PSE)	0	0	0	
X = 0.0005 (PEG)	0.0005	0.0005	0.0005	0.0005
X = 0.3	0.0030	0.0030	0.003	0.0030
S=0, X=0 (PSE)	0	0	0	
S (X=0)	0.0031	0.0031	0.0031	0.0031
S (X=0.0005) (PEG)	0.0026	0.0026	0.0026	0.0026
S (X=0.30)	0.0001	0.0001	0.0001	0.0001
C (X=0) PSE	4.09	3.58	3.83	
C (X=0)	3.84	3.33	3.59	-0.24
C (X=0.0005) (PEG)	3.88	3.37	3.63	-0.20
C (X=0.30)	4.08	3.57	3.82	-0.01
RCI (X=0) PSE	5.49	4.98	5.23	
RCI (X=0)	5.24	4.73	4.99	-0.24
RCI (X=0.0005) (PEG)	5.23	4.72	4.98	-0.25
RCI (X=0.30)	5.18	4.67	4.92	-0.31

*Values for the C Factor and RCI under Hydro One's proposal may differ from those in Exhibit A, Tab 4, Schedule 1, pages 7-8 due to rounding.

c) Were the X factor set at 0.3%, PEG calculates that the ACM equivalent S factor would be 0.01%. However, the OEB may wish to place a lower bound on the S factor at the 0.15% that it chose for Hydro One’s distribution services.

d) No.

e) No.

M1-HON-20

Reference: Exhibit M1, page 45

Preamble: On pages 44 and 45 PEG lists various alternatives for the OEB's consideration. On page 45 PEG states that "The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IR proceeding." PEG then states that after considering the pros and cons of each option that it recommends that the OEB add a supplemental stretch factor calibrated "so that it produces a markdown on plant additions that is similar to what would be produced by an ACM."

Interrogatories:

a) Please confirm that PEG's recommendation of the calibration the S-factor is based on the assumption that no other reductions are made to Hydro One's proposed capital envelope.

b) Please provide a reference in OEB materials that indicates or implies that the OEB intends the ACM/ICM materiality threshold to serve as a "markdown" on capital expenditures.

c) Please explain why the OEB's ACM/ICM mechanism is relevant when the OEB made clear as follows at p. 14 of the *Report of the Board, New Policy Options for the Funding of Capital Investments: the Advanced Capital Module* (emphasis added):

> *…there must be a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year), and the Custom IR method. The use of an ACM is most appropriate for a distributor that:*
>
> *• does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;*
>
> *• is not seeking funding for a series of projects that are More related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or*
>
> *• is not proposing to use the entire eligible incremental capital envelope available for a particular year.*

Response to HON-20: The following response was provided by PEG.

a) PEG believes that the final S factor should reflect the OEB's decision on Hydro One's transmission capital envelope. Disallowances would reduce but would not necessarily eliminate the need for an S factor. The Board disallowed a sizable part of Hydro One's forecasted/proposed capex in the recent distribution IR proceeding and still levied a 0.15% S factor.

b) PEG understands that the OEB prefers the term "dead band" to the term "markdown" when discussing the funding provided by its capital modules. However, the OEB has clearly intended for the materiality thresholds for these modules to include a dead band that effectively marks down eligible capex. For example, in their 2013 decision on Toronto Hydro's proposed Incremental Capital Module application the OEB stated that:

> The Board finds that the wording of the Supplemental Report is clear – that only eligible expenditures in excess of the materiality threshold are eligible for ICM4, and that the purpose of the deadband is to reduce the amount of funding available by a further 20%. The Board finds that the 20% threshold adjustment continues to be appropriate[1]

The Board stated on pages 18-19 of the same decision that

> While the Board will not adopt the suggestion of some parties that each project put forward by THESL should meet the overall materiality threshold, the Board does not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget.[2]

c) The relevance of the ACM/ICM markdown provision is that the OEB deemed a material markdown of forecasted/proposed capex to be warranted, regardless of its chosen X factor, for multiple reasons. For example, the Board stated in EB-2014-0219 that a dead band of 10% balances "the need for appropriately funding necessary incremental capital investments while avoiding numerous marginal applications and providing some protection that amounts are not already funded through rates."[3] These reasons also apply to Custom IR, and PEG has advanced

[1] Decision, EB-2012-0064, May 9, 2013, pp. 15-16.

[2] *Ibid*., pp. 18-19.

[3] EB-2014-0219, p. 18.

other valid reasons for markdowns. The need for a markdown is heightened in this case by the fact that Hydro One's proposed X factor is zero.

HYDRO ONE INTERROGATORIES ON THE WORKING PAPERS OF PACIFIC ECONOMICS GROUP

M1-HON-21

Reference: Exhibit M1, Working Papers

Preamble:
In examining the PEG working papers and on p. 28 of the PEG Report, we understand that PEG subtracted certain cost categories from Hydro One's OM&A expenses to make a more consistent cost definition with the sample. These categories include miscellaneous transmission expenses, load dispatching, maintenance of miscellaneous regional transmission plant, and transmission by others. However, in examining the working papers it only appears that PEG subtracted these costs from Hydro One's OM&A expenses for the years 2008 to 2017 and that when PEG subtracted the expenses for Hydro One the costs were in different units than the rest of the costs. When Hydro One provided these cost breakouts to PEG in updated response to I-01-OEB-12 the company stated that the broken out cost data was only available for the years 2008 to 2017 but that the accounts averaged around 13% of OM&A expenses. The response also mentioned the provided data is in millions of dollars.

Interrogatories:

a) Please confirm that PEG did not subtract these cost categories for the forecasted years of 2018 to 2022 and for years prior to 2007. If confirmed, please explain why PEG did not subtract an estimated portion in these years to make the cost definition consistent with the US sample in years other than 2008 through 2017.

b) Please confirm that in the years of 2008 to 2017, when PEG did subtract these costs, the effect was to only subtract 1/1,000th of the costs that should have been subtracted from Hydro One. For example, in 2017 Hydro One reported $42.7 million in miscellaneous transmission expenses but PEG only subtracted $42.7 thousand for these miscellaneous transmission expenses. Please confirm that our understanding of PEG's methodology in this regard is correct.

Response to HON-21: The following response was provided by PEG.

PEG used the Hydro One data as provided but did not make the adjustments mentioned above. PEG has subsequently fixed the units issue and imputed the 2017-2020 OM&A values using the 2016 ratio of unadjusted OM&A expenses to adjusted OM&A expenses for future years and the 2008 ratio for previous years. The values after 2021 were extended from 2020 using the normal procedure in the code.

Revised benchmarking results are provided in Tables HON 21-A and HON 21-B. The change in results is minor and does not alter PEG's main conclusion that a 0.30% stretch factor is appropriate for Hydro One's transmission services. It can be seen that the revised average cost performance score for the 2020-2022 period is 6.8% rather than 9.0%. Neither the new nor the old benchmarking scores are statistically different from zero. One reason that the change in the score is small is that OM&A is a very small part of total cost in the forecast period. The MFP trend of the Company over the full 2005-2016 historical sample period is -1.18% rather than -1.17% if these costs are excluded. The new MFP results are presented in Table HON 21-C.

The reason to exclude these costs was to provide better comparability with the US MFP results, which does not apply to a stand-alone analysis of HON TFP. PEG believes that the MFP trend with no exclusions could be seen as more reliable because it does not require the imputations needed due to missing data. The MFP trend with no exclusions is presented in Table HON 21-D.

Please note also that the output parameters yielded the same output weights as before (46.3% weight on line length) and no change to the US MFP results was required.

a) Confirmed

b) Confirmed

Table HON 21-A

PEG's Alternative Econometric Model of Total Transmission Cost

VARIABLE KEY

YM = Kilometers of transmission line
P = Ratched maximum peak demand
MVA = Substation capacity per substation
VOLT = Average voltage of transmission line
CS = Construction standards index
PCTPOH= Percent of transmission plant that is overhead
PCTPTX = Percent of transmission plant in total plant
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YM	0.491	26.098	0.000
YM * YM	0.401	14.459	0.000
P	0.569	30.508	0.000
P * P	0.241	7.257	0.000
YM * P	-0.207	-8.478	0.000
MVA	0.044	2.347	0.019
VOLT	0.062	2.045	0.041
CS	0.234	5.165	0.000
PCTPOH	-0.397	-8.390	0.000
PCTPTX	0.138	10.300	0.000
Trend	-0.006	-7.295	0.000
Constant	12.173	695.355	0.000

Adjusted R^2	0.948
Sample Period	1995-2016
Number of Observations	1,127

Table HON 21-B

Hydro One's Total Transmission Cost Performance

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-23.4%
2005	-26.0%
2006	-25.4%
2007	-22.6%
2008	-23.8%
2009	-21.5%
2010	-18.9%
2011	-15.9%
2012	-13.9%
2013	-7.5%
2014	-7.2%
2015	-4.2%
2016	-3.7%
2017	-0.8%
2018	-0.1%
2019	1.3%
2020	4.0%
2021	6.5%
2022	9.9%
Average 2004-2016	**-16.5%**
Average 2014-2016	**-5.0%**
Average 2020-2022	**6.8%**

[1] Formula for benchmark comparisons is $\ln(Cost^{HON}/Cost^{Bench})$.

Table HON 21-C

Hydro One's Transmission Productivity Annual Growth Rates - Revised

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities			Productivity		
		OM&A	Capital	Multifactor	OM&A	Capital	Multifactor
2004							
2005	1.43%	-9.42%	0.32%	-1.59%	10.85%	1.11%	3.02%
2006	1.88%	10.14%	-0.22%	1.83%	-8.26%	2.10%	0.05%
2007	0.00%	10.51%	1.46%	3.40%	-10.51%	-1.46%	-3.41%
2008	0.08%	-13.40%	0.32%	-2.56%	13.48%	-0.24%	2.64%
2009	-0.01%	7.56%	2.49%	3.50%	-7.57%	-2.50%	-3.51%
2010	0.04%	-0.11%	3.87%	3.08%	0.15%	-3.83%	-3.04%
2011	0.04%	-4.51%	3.01%	1.57%	4.55%	-2.97%	-1.53%
2012	0.44%	-2.32%	5.68%	4.22%	2.76%	-5.24%	-3.78%
2013	0.03%	5.69%	1.52%	2.27%	-5.66%	-1.50%	-2.24%
2014	-0.05%	-9.84%	2.77%	0.61%	9.80%	-2.82%	-0.66%
2015	0.15%	1.26%	0.71%	0.80%	-1.12%	-0.57%	-0.66%
2016	0.00%	-4.78%	2.14%	1.06%	4.78%	-2.14%	-1.06%
2017	-0.58%	-3.06%	1.77%	1.05%	2.49%	-2.35%	-1.62%
2018	0.61%	-4.49%	3.25%	2.14%	5.11%	-2.64%	-1.53%
2019	0.00%	-16.81%	1.78%	-0.61%	16.81%	-1.77%	0.62%
2020	0.00%	4.06%	2.03%	2.27%	-4.06%	-2.03%	-2.27%
2021	0.01%	-0.10%	3.13%	2.75%	0.10%	-3.12%	-2.74%
2022	0.01%	-0.10%	2.77%	2.44%	0.11%	-2.76%	-2.43%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.77%**	**2.01%**	**1.52%**	**1.10%**	**-1.67%**	**-1.18%**
2012-2016	**0.11%**	**-2.00%**	**2.57%**	**1.79%**	**2.11%**	**-2.45%**	**-1.68%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.59%**	**0.11%**	**-2.94%**	**-2.58%**

[1]All growth rates are calculated logarithmically.

Table HON 21-D

Hydro One's Transmission Productivity Annual Growth Rates with No Exclusions

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities OM&A	Input Quantities Capital	Input Quantities Multifactor	Productivity OM&A	Productivity Capital	Productivity Multifactor
2004							
2005	1.43%	-9.42%	0.32%	-1.80%	10.85%	1.11%	3.23%
2006	1.88%	10.14%	-0.22%	2.06%	-8.26%	2.10%	-0.18%
2007	0.00%	10.51%	1.46%	3.62%	-10.51%	-1.46%	-3.62%
2008	0.08%	-15.00%	0.32%	-3.23%	15.08%	-0.24%	3.32%
2009	-0.01%	11.84%	2.49%	4.56%	-11.85%	-2.50%	-4.57%
2010	0.04%	-1.38%	3.87%	2.69%	1.42%	-3.83%	-2.65%
2011	0.04%	-4.07%	3.01%	1.48%	4.11%	-2.97%	-1.44%
2012	0.44%	0.19%	5.68%	4.54%	0.24%	-5.24%	-4.10%
2013	0.03%	2.30%	1.52%	1.68%	-2.27%	-1.50%	-1.65%
2014	-0.05%	-11.22%	2.77%	0.09%	11.17%	-2.82%	-0.14%
2015	0.15%	9.93%	0.71%	2.43%	-9.78%	-0.57%	-2.29%
2016	0.00%	-9.69%	2.14%	-0.03%	9.69%	-2.14%	0.03%
2017	-0.58%	-5.26%	1.77%	0.57%	4.68%	-2.35%	-1.15%
2018	0.61%	-1.98%	3.25%	2.40%	2.59%	-2.64%	-1.78%
2019	0.00%	-16.81%	1.78%	-0.99%	16.82%	-1.77%	1.00%
2020	0.00%	4.06%	2.03%	2.31%	-4.06%	-2.03%	-2.31%
2021	0.01%	-0.10%	3.13%	2.69%	0.10%	-3.12%	-2.68%
2022	0.01%	-0.10%	2.77%	2.38%	0.11%	-2.76%	-2.37%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.49%**	**2.01%**	**1.51%**	**0.83%**	**-1.67%**	**-1.17%**
2012-2016	**0.11%**	**-1.70%**	**2.57%**	**1.74%**	**1.81%**	**-2.45%**	**-1.63%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.53%**	**0.11%**	**-2.94%**	**-2.53%**

[1]All growth rates are calculated logarithmically.

M1-HON-24

Reference: Exhibit M1, Working Papers

Preamble: On p. 59 of the PEG Report, PEG mentions its econometric model estimation procedure now corrects for autocorrelation, whereas in the HOSSM proceeding it did not. Normally, a small change in results would be expected due to making such a methodological change. Yet, PSE notices a large difference in results from PEG's HOSSM proceeding and a large difference in PEG's results relative to a model estimated using Pooled Ordinary Least Squares (OLS) that PSE was able to estimate from PEG's working papers.

Interrogatories:

a) Would PEG normally expect a large change in results based on the autocorrelation methodological change made by PEG relative to either an OLS model or PEG's Generalized Least Squares model reported in the HOSSM case?

b) Given the PEG approach in HOSSM was a valid approach and an OLS modelling approach still produces unbiased parameter estimates even in the presence of autocorrelation and heteroskedacity, is PEG concerned about the large change in results stemming from its modeling procedure now used in this application?

c) Please list the applications in PEG's prior cost benchmarking research in Ontario where PEG's econometric modeling procedures included this same autocorrelation correction. The list of possible applications should include 3rd Generation IR model, 4th Generation IR model, two Toronto Hydro Custom IR applications, Hydro One Distribution Custom IR, and the Hydro One SSM application.

d) Please list the applications in PEG's prior cost benchmarking research in Ontario where PEG's econometric modeling procedures did not include this same autocorrelation correction. The list of possible applications should include 3rd Generation IR model, 4th Generation IR model, two Toronto Hydro Custom IR applications, Hydro One Distribution Custom IR, and the Hydro One SSM application.

Response to HON-24: The following response was provided by PEG.

a) Please see the response to part (b).

b) In our work for Board Staff in the HOSSM proceeding, PEG did not make the autocorrelation correction that we normally do. Thus, while the estimation procedure for the new model was valid, that for our model in the HOSSM proceeding was not. It is true that OLS is unbiased even in the presence of autocorrelation and heteroskedasticity. However, being unbiased only means that parameter estimates do not deviate *systematically* from their true values. It does not mean that any *particular* estimate will be close to the true value. Thus, an estimator that is unbiased is not necessarily a good estimator. For example, if the true value of a parameter is zero, an estimator that yields 100 and -100 with equal frequency is unbiased. In the presence of autocorrelation and heteroskedasticity, the efficiency (i.e., precision) of the OLS approach declines—so while its estimates generally remain unbiased, any particular estimate may differ substantially from those produced by a more efficient approach (such as the FLGS procedure used by PEG). Thus, it is plausible that PEG's new econometric estimates and resulting benchmarks could differ materially from analogous OLS results or from our HOSSM results.

c) and d) PEG has not always specified in our reports the exact autocorrelation correction specification used in the development of our econometric cost models. To answer these questions, we would accordingly need to review our working papers for various projects dating back at least 10 years. PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding. However, PEG has used its best efforts to provide information below as to whether an autocorrelation correction was undertaken in our Ontario research.

PEG corrected for autocorrelation in our econometric research for IRM4, the Hydro One distribution IR proceeding, and the two Toronto Hydro IR proceedings. We believe that a feasible GLS method was used in all cases. In several additional reports, notably for the 3rdGIRM proceeding and in EB-2014-0116, PEG relied on an FGLS approach to model estimation but did not report whether an autocorrelation correction was made. PEG did not correct for autocorrelation in our work in the 2007 IR proceedings for Enbridge Gas and Union Gas in Cases EB-2007-0606/0615 or in the Hydro One Sault Ste. Marie IR proceeding. PEG did not specify whether an autocorrelation correction was made in our 2006-2008 benchmarking reports (EB-2006-0268).

PEG understands that PSE did not correct for autocorrelation in the recent Toronto Hydro IR proceeding.

M1-VECC-2

References: Exhibit M1, Page 45

Preamble:

At the reference below the author makes the following statement:

> Hydro One should, in our view, be permitted to keep a share of the value of any capex underspends. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends.

Interrogatory:

a) Since there is both an incentive to contain actually capital spending, but also an offsetting incentive to exaggerate capital budgets, what evidence do the authors have that there is a net benefit to the proposal? Specifically, what evidence do the authors have to refute the hypothesis that the net result of a scheme - in which ratepayers pay for 5% of non-built (fictitious) capital - is negative?

b) If it is true and there is an incentive to exaggerate capex needs can one then presume that the capital expenditure forecasts presented by the Hydro One in this application are inherently too high? If so (or if not) how would that be determined?

Response to VECC-2: The following response was provided by PEG.

a) PEG believes that there can be net benefits from sharing capex underspends with utilities. Incentives to contain capex would be strengthened. Capex savings could lower rates at the next rebasing.

   There are some protections for customers. For example, sharing with customers is possible for underspends but not overspends. Commissions have some ability to appraise capex proposals. The OEB, for example, has requested transmission and distribution system plans and has disallowed sizable portions of some recent capex proposals by utilities. Schemes to qualify for extra revenue by needlessly bunching capex can be recognized, through the analysis of historical spending and through testing of 5-year system plans. The OEB can also monitor the tendency of a utility to spend less than its capex proposal, particularly at the time of subsequent periodic applications to rebase rates.

Precedents for such sharing provisions in the regulation of other utilities shed light on their potential merit. PEG has not undertaken a comprehensive survey of approved cost tracker sharing provisions but is aware of several examples. Most notably, this type of incentive mechanism has been approved for capex in jurisdictions that include California, Britain, and British Columbia.

- In BC, at least 5 certificates of public convenience and necessity have been approved for gas and electric utilities which allow the utility to share in capex variances.
- In California, funding mechanisms for build outs of gas and electric automated metering infrastructure have on several occasions included provisions for the utility to share capex variances.
- In Britain, utilities may share in both underspends and overspends of *total* expenditures (aka "totex") relative to approved amounts. Given VECC's evident concern about utility exaggerations, it is notable that the utility's share of expenditure variances is tied to how reasonable the utility's expenditure forecast is deemed to be by Ofgem. This provision is part of Ofgem's complicated information quality incentive.

Details of some capital tracker sharing mechanisms can be found in the table below. Sharing mechanisms have also been approved in North America for energy (e.g., generation fuel) procurement and other operating revenues. For example, Portland General Electric receives or pays 90% of the variances outside of a dead band so long as the recovery does not cause the company's ROE to vary by more than 100 basis points from the allowed ROE. Similar mechanisms were approved for utilities in Missouri, New York, and Washington. It should also be noted that many multiyear rate plans have been approved over the years in which utilities keep the benefits of all capex underspends or share them only through an earnings sharing mechanism.

b) Despite Hydro One's incentive to exaggerate its capex requirements it has not necessarily done so. PEG is an expert on incentive regulation and can speak with some authority on the Company's incentive to exaggerate its capex requirements. However, we were not retained to review the Company's capex proposal and do not have an opinion on whether it is reasonable.

Regulators in other jurisdictions (e.g., Australia and Britain) use econometric benchmarking and engineering models and retain engineering consultants to appraise utility capex proposals. An econometric capex benchmarking model could include as a variable the share of utility assets exceeding the average service life.

Table VECC-2

Details of Incentivized Capital Cost Trackers

Jurisdiction	Company Name	Services	Eligible Investments	Special Treatment of Cost Variances	Case Reference
BC	Terasen Gas (now FortisBC Energy)	Gas	Customer Care Enhancement Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Order C-1-10
BC	Terasen Gas Vancouver Island (now FortisBC Energy)	Gas	Gas pipeline lateral from Squamish to Whistler	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Orders G-53-06, and G-76-06
BC	Terasen Gas Whistler (now FortisBC Energy)	Gas	Conversion of Whistler Gas system from propane to methane, meter/regulating station	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order G-53-06
BC	BC Gas (now FortisBC Energy)	Gas	Southern Crossing Pipeline Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk.	Order G-51-99
BC	FortisBC	Bundled power service	Big White Supply Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order C-17-06
CA	San Diego Gas & Electric	Power and Gas Distribution	Advanced metering infrastructure ("AMI")	No deadband. Asymmetrical mechanism wherein 90% of the first $50 million over the cap and 10% of first $50 million under the cap allocated to shareholders (No prudence review required)	Decision 07-04-043 (April 2007)
CA	Southern California Edison	Power Distribution	Deployment of AMI	No deadband. Asymmetrical Mechanism wherein 90% of first $100 million over the cap charged to customers (No prudence review required)	Decision 08-09-039 (September 2008)
CA	Southern California Gas	Gas	AMI	Overrun sharing mechanism: Up to $50 million to be paid by shareholders, calculated as 50% of first $100 million over total cost; Underrun sharing mechanism: Up to $10 million to be received by shareholders, calculated as 10% of first $100 million under total cost.	Decision 10-04-027 (April 2010)

TAB 2

INTERROGATORY #6

Reference: Exhibit M1, page 4

PEG states about the PSE research: “The calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate. For example, the benchmark year was 1989 whereas a benchmark year of 1964 is possible. Capital cost was not calculated net of capital gains.”

a. The 4th Generation Incentive Regulation productivity and benchmarking research conducted by PEG used a benchmark year of 1989 or 2002 for the Ontario distributors depending on data availability. Due to the use of the 1989 benchmark year in the 4th Generation IR proceeding, does PEG consider the capital measurement in their own 4th Generation IR study to be inaccurate? If not, why not?

b. The 4th Generation Incentive Regulation productivity and benchmarking research conducted by PEG calculated capital cost without accounting for capital gains. PSE used the same 4th Generation Incentive Regulation procedure in the present application. Does PEG consider the capital measurement in their own 4th Generation IR study to be inaccurate? If not, why not?

c. What was the capital benchmark year that PEG used in their benchmarking research for Hydro One Distribution in EB-2017-0049?

d. Did PEG calculate capital costs net of capital gains in their benchmarking research for Hydro One Distribution in EB-2017-0049? If not, please explain why capital costs are being calculated differently in PEG’s current research.

e. When calculating transmission revenue requirements in a regulated environment, the cost of capital typically includes a weighted average cost of capital (WACC) plus depreciation. When calculating revenue requirements, are capital gains typically accounted for in the regulatory cost of capital?

f. In examining PEG’s working papers, PEG’s capital cost measure fluctuates widely during the sample period despite capital costs being built up by a series of investments for prior decades. For PEG’s first utility in the U.S. sample (PEGID = 2), in 2006 PEG’s capital cost is less than half of what it was just two years prior in 2004. The capital cost then doubles in just one year from 2008 to 2009, other fluctuations are observed in other years. Similar results are present for all utilities in the sample. This result is contrary to the capital cost portion in the revenue requirement which is typically far more stable.

i. Please confirm these large fluctuations in capital cost are due to PEG's capital gains procedure in calculating capital cost.
ii. Please confirm that PEG calculated the capital gains term using a 3-year smoothing technique in an attempt to dampen these large annual capital cost fluctuations and the fluctuations would be even more pronounced if PEG did not impose this further modification onto the capital price definition.
iii. Please confirm PEG's capital gains procedure will have a meaningful impact on the OM&A and capital cost shares found in the study.
iv. Please confirm that since asset prices typically increase over time, PEG's capital gains procedure will tend to lower the measured capital costs of the sample.
v. Please confirm PEG's capital gains procedure will tend to give a higher cost share weight to OM&A.

g. In examining the benchmarking working papers and the older capital data used by PEG in the file "bmdattx1.sav" to produce a benchmarking year of 1964 there appeared to be several suspicious data points in the older capital data used by PEG. Without naming the utilities there appear to be zero transmission plant additions for two utilities from 1965 to 1967 (PEGID = 92 and PEGID = 183). Please confirm these utilities had zero transmission plant additions for three consecutive years. If confirmed, is this data plausible in PEG's opinion?

h. In examining the PEG benchmarking working papers and the older capital data used by PEG in the fie "bmdattx1.sav" to produce a benchmarking year of 1964 there appeared to be several suspicious data points in the older data used by PEG. Without naming the utilities, several additional utilities had what appears to be implausibly low plant additions during the 1960's and 1970's for the benchmarking data used by PEG. We provide two examples but several other suspicious data beyond these appear to be present in the older data used by PEG. In one example in PEG's dataset, one large sampled utility (PEGID = 143) averaged plant additions of 0.094% per year relative to the 1964 transmission net plant value for a ten-year period (1965 to 1974). During that 10-year period transmission plant additions never exceeded 0.38% of the 1964 net plant value. Additions then increased by a multiple of 40 to more normal levels starting immediately in 1975. The percentage never got below 5.44% in all 42 years after 1974.

In a second example in PEG's older capital dataset, a large utility (PEGID = 47) about the size of Hydro One Networks in terms of reported transmission peak demand and having over 10,000 km of transmission lines, has transmission plant additions less than $1 million for 24 straight years from 1965 to 1988. This averages 0.31% of the 1964 transmission net plant value for that 24-year period. However, in 1989 the data again rises steeply to more normal values (the utility spent over $45 million in 1989) and never comes close to the prior numbers in that 24-year period of the older data. From 1989 to 2016 the reported plant additions never falls below 24.01%.

i. Please confirm these examples and, if confirmed, does PEG find these examples to be suspicious? If not, please explain how transmission plant additions can be so low for an extended 10-year or a 24-year period.
ii. Does PEG have the source data for all the observations in PEG's 1964 to 1987 capital dataset. If so, please provide PDFs on a confidential basis so we can verify these observations.

i. In examining the working papers there appears to be large differences for several observations in the underlying older transmission plant addition data PEG used for the benchmarking study and for the TFP study. It is our understanding that in the TFP study the file "txdata16.sav" is bringing in the transmission plant additions, whereas in the benchmarking sample "bmdattx1.sav" is bringing in the capital data. In the benchmarking file, the examples cited in part (e) and part (f) of this interrogatory appear plus many other discrepancies between the capital data PEG is using for the TFP study and for the benchmarking study. For the TFP study the data is different and seems far more plausible when examining the older capital additions data.

i. Please confirm the underlying capital data is different for numerous observations in PEG's TFP and benchmarking studies and, if so, please discuss why.
ii. The benchmarking capital plant additions for the U.S. sample appear to be considerably lower than the TFP capital additions data used by PEG for most of the observed differences. Please confirm.

j. Leaving all other PEG methods and procedures the same as those employed in the PEG report, please provide the results of changing the benchmark year to 1989 for the U.S. sample. Please provide a revised Table 2 and Table 4 when making this change.

k. Leaving all other PEG methods and procedures the same as those employed in the PEG report, please provide the results calculating capital cost without netting capital gains. Please provide a revised Table 2 and Table 4 when making this change.

Response to Hydro One SSM-6: The following response was provided by PEG.

a. In the 4th GIRM proceeding the OEB decided to base the X factor and total cost benchmarking for provincial power distributors on Ontario data, and PEG was asked to calculate the productivity trends of these distributors. PEG used the earliest benchmark year that was practical for these calculations. PEG has noted in some recent reports for the OEB that the benchmark years available for Ontario distributors do not facilitate accurate total cost benchmarking or productivity measurement. PEG believes that a a 1989 benchmark year is good enough to warrant statistical total cost benchmarking, but should not be used if, as in this case, a considerably earlier benchmark year is practical. The impact of improved accuracy is something to be demonstrated. PEG found a modest improvement as a result.

b. The accuracy of the Ontario capital cost data should improve over the years as the benchmark year recedes into the past.

c. The term “unnecessarily inaccurate” in PEG’s commentary was intended to apply more to the use of a more recent benchmark year than the capital gains. However, the subtraction of capital gains is consistent with the theory behind geometric decay service prices. A low real rate of return should encourage capital expenditures. PEG found that using the simplified method that excluded capital gains would have raised the TFP trend by about 10 basis points. This is because it affects the weight given to capital and not the quantity of capital. Dr. Lowry was not supervising the IRM-4 work in which the simplified method was used. Other PEG staff recall that the one of the reasons for adopting a simplified treatment is that the audience for this work was all Ontario distributors and PEG and OEB staff wanted to present methods that were easier to understand while still reasonably accurate. In the context of a single application by a company with the size and resources of Hydro One Transmission, to which the PSE study directly pertains, PEG feels that it is better to use the more complex method that is more consistent with the theory.

d. No. PEG used the same benchmark year as PSE in that proceeding. The reason is that PEG was not authorized by OEB Staff in this proceeding to undertake its own benchmarking study.

e. PEG acknowledges that traditional ratemaking does not consider capital gains when fashioning revenue requirements. However, it also values assets in historical dollars. When capital cost is calculated using geometric decay without capital gains, it is overstated. There are other methods available for calculating capital cost if consistency with ratemaking is a priority. The service price approach using geometric decay is not intended to mimic ratemaking to allow for the recovery of company-owned capital. The service price approach abstracts from self-ownership of assets by setting capital service price as level that would hypothetically be faced is a company had to rent the assets it actually owns in a competitive market for capital assets. In this context, capital gains are relevant.

f. We comment below on each of these statements.

i. This statement is confirmed. However, the fluctuations in capital cost are due to fluctuations in the capital price.

ii. This statement is confirmed. PEG believes that the smoothing it undertakes may better reflect the expected escalation of the real rate of return.

iii. This statement is confirmed.

iv. This statement is confirmed, and this is desirable since assets are valued in current dollars.

v. This statement is confirmed.

g. Please see the response to part i. The values for PEGID 92 are present in the TFP version of the database. The missing values for PEGID 183 were due to combined T&D reporting in those years. As noted in the working papers, PEG discovered this issue after our report was filed. An imputation was provided to separate the values such that other parties could make this correction if they wished. This change is incorporated in PEG's revised results reported in part i of this question.

h.

i. PEG acknowledges that the examples cited by PSE were reflected in our research. PEG agrees that these observations are suspicious. Please see the response to part I of this question. PEGIDs 47 and 143 each had uncorrected mergers in the benchmarking data that caused the low values. These changes are incorporated in PEG's revised results reported in part i.

ii. Yes. PEG believes that this is an onerous request and that this data is available at the University of Wisconsin-Madison and many large universities across the U.S.

i. PEG confirms both statements. The benchmarking and TFP studies were done separately and the benchmarking plant additions data were unintentionally inconsistent with those used in the productivity work. This was due to an error in which the older plant additions data were not corrected for mergers by aggregating the historical data for predecessor companies. This led to flawed data in the benchmarking calculations and explains most of the observations in other questions. The resolution of consistency issues between the studies led to a non-negligible change in PEG's benchmarking work that improved the cost performance of Hydro One. The productivity trends were not significantly affected by these revisions. Revised productivity and benchmarking results are Attachments PEG-HOSSM 6-i (a) through (d).

Revised results presented below also reflect more minor issues raised here and by other parties. Revised productivity results are also provided which reflect the changed weighting of outputs as a result of the revised econometric work and correction of a few missing data points noted by other parties.

Also included in PEG's response is a table with variations on the MFP trend results that show the impact of various changes to the PSE methodology made by PEG. The working papers provided contained code that allowed choices for different methodologies used by PEG vs. PSE. PEG grouped them in several broad areas. The first set of changes excluded HON from the calculations, separated transmission and general capital stocks and used PEG data with the exception of using PSE 1989 data for net plant, peak demand and miles of line. These changes collectively moved the 2005-2016 trend from -1.86% to -1.90%. The second set of changes focused on the scale index and introduced PEG elasticity weights, PEG data on miles and peak, and used a PEG rate of return that allowed for the use of a longer time period. These changes collectively changed the shorter PSE trend from -1.90% to -1.87% and produced a 1996-2016 trend of -1.36%. The third set of changes focused on O&M and included changes to scope of O&M cost considered, a different allocator for A&G expenses, and a regionalized price for labor inputs. Collectively these changes moved the trend for the shorter PSE term from -1.87% to -2.15% and for the longer PEG trend from -1.36% to -0.66%. The last set of changes made were capital-related. These changes included the earlier 1964 benchmark year and capital gains treatment. Collectively, these changes move the TFP trend from -2.15% to -1.88% for the PSE time period and from -0.66% to -0.36% for the longer PEG time period.

The foregoing analysis was not burdensome to complete because it is what PEG used for its internal reconciliation process and was already coded and provided as part of the working papers. PEG believes it addresses many of the requested alternative versions of the productivity work.

j. The impact on TFP is included in the response to part i. Due to the significant number of requests for alternate versions, and the schedule established by the OEB in Procedural Order No. 5, issued March 14, 2019, for submissions in the case, PEG cannot undertake all of this work.

k. PEG found an increase in TFP of about 10 basis points as a result. The impact on TFP is included in the response to part i. Due to the significant number of requests for alternate versions, and schedule established by the OEB in Procedural Order No. 5, issued March 14, 2019, for submissions in the case, PEG cannot undertake all of this work.

Attachment PEG-HOSSM-6i(b)

Hydro One's Total Transmission Cost Performance Using PEG's Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-41.20%
2005	-44.20%
2006	-43.30%
2007	-38.50%
2008	-41.00%
2009	-34.70%
2010	-32.40%
2011	-31.80%
2012	-27.90%
2013	-25.30%
2014	-25.00%
2015	-21.60%
2016	-22.00%
2017	-20.50%
2018	-18.70%
2019	-16.40%
2020	-13.70%
2021	-11.00%
2022	-8.30%
Average 2004-2016	**-32.99%**
Average 2014-2016	**-22.87%**
Average 2019-2022	**-12.35%**

[1] Formula for benchmark comparison is $\ln(Cost^{HOSSM}/Cost^{Bench})$.

TAB 3

Ontario Energy Board

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

Commission de l'énergie de l'Ontario

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

Ontario

BY EMAIL

January 8, 2019

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Hydro One Sault Ste. Marie LP
2019 Electricity Transmission Rate Application
OEB Staff Letter Regarding Expert Evidence, 2019 – 2026 Revenue Cap Plan
OEB File No. EB-2018-0218

In accordance with the Decision on Confidentiality and Procedural Order No. 3 issued by the Ontario Energy Board (OEB) on December 14, 2018, please find below a summary of the expert evidence that OEB staff plans to file in this proceeding.

OEB staff has retained Pacific Economics Group Research LLC (PEG) to provide one or more reports presenting PEG's review of the evidence prepared by Power Systems Engineering Inc. (PSE) for Hydro One Sault Ste. Marie LP (Hydro One SSM) with respect to the total cost performance and total factor productivity trends of Hydro One Networks Inc. transmission (Hydro One Transmission) relative to a comparator sample of U.S. electricity transmitters. OEB staff notes that it is this evidence of PSE on which Hydro One SSM has based the productivity and stretch factors of its proposed revenue cap plan.

PEG's analyses will include a detailed review of PSE's report and working papers, and may include new analyses of the cost performance and productivity trends of Hydro One Transmission and the comparator U.S. peer group. PEG's report may also touch on some of the more detailed cost benchmarking work included in Hydro One SSM's application. PEG will assess key aspects of Hydro One SSM's proposed revenue cap plan and provide commentary in the report, discussing salient alternatives, and precedents from other jurisdictions, where relevant.

In addition, PEG staff will prepare responses to interrogatories related to its evidence; assist in the drafting of OEB staff submissions; and attend any technical conference or oral hearing as necessary.

While a team of staff at PEG will work on this engagement, the principal whom OEB staff intends to offer as an expert witness is Dr. Mark Lowry, president of PEG. Dr. Lowry is leading the team at PEG and is an economist who has testified on matters of economic analysis, total and partial factor productivity analysis, cost benchmarking, and incentive regulation, in Ontario, Alberta, Québec, in U.S. jurisdictions and internationally. Dr. Lowry and PEG have been involved in policy consultative processes and applications in Ontario for over 10 years. Of particular relevance is Dr. Lowry's evidence and testimony on similar total factor productivity and cost benchmarking analysis in the following three recent applications to the OEB for approval of rate setting plans for electricity and natural gas distribution and for Ontario Power Generation Inc.'s prescribed hydroelectric generation assets:

- EB-2016-0152: Ontario Power Generation Inc.'s 2017-2021 rate setting plan for prescribed nuclear and hydroelectric generation payment amounts
- EB-2017-0049: Hydro One Networks Inc.'s 2018-2022 Custom Incentive Rate-setting plan for distribution rates
- EB-2017-0306/EB-2017-0307: Amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited and Rate-Setting Mechanism.

The estimated budget for PEG's work in preparing its evidence in this proceeding is approximately $210,000. There will be additional costs for matters such as interrogatory responses, drafting of submissions, and hearing attendance that are not included in the evidence preparation costs above.

Yours truly,

Original signed by

Fiona O'Connell
Project Advisor, Major Applications

cc: Hydro One Sault Ste. Marie LP
All registered parties to EB-2018-0218

TAB 4

Ontario Energy Board

Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET
Ontario

EB-2014-0219

Report of the Board

New Policy Options for the Funding of Capital Investments: The Advanced Capital Module

September 18, 2014

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1 Introduction

On July 18, 2014, the Board released Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications (for applications filed under cost of service). In that document the Board continued its promotion of a change to the way electricity distributors think about the future. The Filing Requirements noted that the *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") "emphasized the importance of good distribution system planning, including optimizing, prioritizing and pacing distributor's capital expenditures to control costs and promote rate predictability."

The Board also noted that it will "review the single test year application not just in the context of the projects and programs that are requested for the test year, but from the perspective of the distributor's plans for the subsequent four years until the next scheduled rebasing application. It is the Board's expectation that at a minimum, cost of service proceedings will consider the entire five year distribution system plan as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the Distribution System Plan."

In this *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the "ACM Report"), the Board continues its progress towards incenting electricity distributors to develop and justify a long-term strategy for delivering distribution services that their customers value and that reflect manageable rate impacts over the long term. Accordingly, this ACM Report establishes a new mechanism to assist electricity distributors in these efforts.

This ACM Report is the culmination of the first phase of a brief consultation initiated by the Board on June 20, 2014. The consultation was on *New Policy Options for the Funding of Capital Investments* (EB-2014-0219). In the letter initiating the consultation, the Board indicated that Board staff had developed two new policies on which it will be seeking comments before bringing the new policy options to the Board for consideration:

- The elimination of the effect of the half year rule on test year capital additions for the intervening years between rebasing applications; and

- The introduction of a new funding mechanism that would enable review during a cost of service application for the need and prudence of any incremental capital module funding requests for discrete projects that are part of a distributor's

Distribution System Plan, and that are planned to come into service during the IRM period (the Advanced Capital Module or "ACM").

It was the Board's intention that these policy options, if approved, would be available to distributors under the Price Cap IR option. They would not apply to distributors under the Annual Index option. Distributors that have specific needs for capital funding that cannot be accommodated under Price Cap IR, should consider whether their specific circumstances would be best addressed through an application for a 5-year Custom IR plan.

A working group consisting of several representatives from electricity distributors who had adopted the Price Cap IR option for 2015 rates, as well as other stakeholders, was convened on June 25, 2014. Based on the feedback provided by the working group, the Board has decided to establish the Advanced Capital Module mechanism.

The purpose of this ACM Report is to articulate the Board policy on the ACM, and how the current policy regarding the Incremental Capital Module ("ICM") mechanism is changing.

The Board does not intend to proceed with the elimination of the effect of the half year rule on test year capital additions for the IRM years at this time. The Board will continue to review this matter and may proceed with a further consultation at some point in the future.

2 Background

In July and September of 2008 the Board established its framework for 3rd Generation Incentive Regulation with the release of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "July 2008 Report of the Board")*, and the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - EB-2007-0673)* (the "Supplemental Report"), respectively. As part of that framework, the Board introduced the approach for the ICM as a means by which a distributor could apply for and receive funding for significant capital projects that would be undertaken in years between cost of service applications.

The ICM was intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The materiality threshold represented a distributor's financial capacities underpinned by existing rates, including growth. The requested amount for an ICM claim had to satisfy the eligibility criteria of materiality, need and prudence as set out in section 2.5 of the July 14, 2008 Report of the Board. Notably, the “need” criterion involved a demonstration that the amounts should be directly related to the claimed driver, which must be clearly non-discretionary.

The ICM was in essence a funding mechanism for significant capital projects for which a utility required rate recovery in advance of its next regularly scheduled cost of service application. Distributors were required to make specific requests for ICM funding as part of their incentive regulation mechanism (“IRM”) applications. Applications were required to be accompanied by comprehensive evidence to support the claimed need as well as the proposed rate riders to establish the funding for the IRM period. Approved projects would then flow into the distributor’s rate base at their remaining net book value, at the time of the next cost of service application.

Since 2008, the Board has reviewed 13 applications for ICM funding. Appendix C to this Report is a listing of these applications.

While the three key criteria of materiality, need and prudence have underpinned the review of all applications filed to date, the Board has evolved its approach to the ICM over the years, specifically with respect to its scope.

2.1 The Evolution of the Scope of the ICM

Preceding this ACM Report, the Board did not issue an updated policy paper on the ICM. The Board’s policy and specifically, the criteria underpinning that policy have evolved and been refined in the Board’s decisions which have in turn been incorporated into the Board’s Filing Requirements over the years.

In the first application before the Board for an ICM, Hydro One Networks Inc.[1] identified its capital budget for the 2009 rate year and requested approval for ICM funding for the entire difference between the capital budget and the materiality threshold. In its decision, the Board noted that:

> *In considering Hydro One's application in this case it is apparent that Hydro One has conflated the calculation of the threshold and the eligibility criteria. While the relationship between depreciation expense and capital spending establishes the base materiality threshold, the relationship itself is not the determinative factor in assessing the appropriateness of the use of the incremental capital*

[1] *EB-2008-0187*

> *module. Hydro One has substantially predicated its application on the gap between its depreciation expense and its capital spending plan. In fact what the Board requires in considering an application under the incremental capital module is a demonstration that the distributor is facing extraordinary and unanticipated capital spending requirements; i.e. something other than the normal course of business. (Emphasis added)*

While the Board's September 2008 Supplemental Report specifically refers to unusual circumstances in giving rise to eligibility under the module, the Board noted that Hydro One's claim that the gap between its depreciation expense and its capital spending could not be considered unusual circumstances given that Hydro One had been operating since 2002 with a similar gap. While the Board afforded some relief to Hydro One, it did not consider Hydro One's application under the Incremental Capital Module. The Board thus evolved the ICM policy through this decision by clarifying that projects were not only required to be part of a capital budget that is incremental to the materiality threshold, but must also be driven by capital spending requirements that are extraordinary and unanticipated.

No ICM applications were filed for the 2010 rate year. For the 2011 rate year, two distributors filed requests for ICM funding in relation to new municipal transformer stations. In its decisions for Oakville Hydro Electricity Distribution Inc. and Guelph Hydro Electric Systems Inc.,[2] the Board approved ICM funding for both applications noting that the projects were non-discretionary expenditures that were clearly outside of the base upon which rates were derived.

These two decisions clarified two significant principles. First, they clarified that ICM requests must first establish the amount of eligible capital available to distributors by subtracting the materiality threshold result from the total non-discretionary capital budget for the subject year. This clarification was consistent with the Board's decision on Hydro One's 2009 application which noted that the mere existence of a gap between the threshold and the capital budget is not determinative for ICM funding.

Second, in approving ICM funding for transformer stations, which have longer lead times for design and construction as compared to most other distribution-related capital projects, the Board had in essence set aside the criteria of extraordinary and

[2] *EB-2010-0104 and EB-2010-0130 respectively*

unanticipated. This was reflected in the Board's 2013 Filing Requirements[3] in which these criteria were removed.

To date, nine out of the 13 ICM applications filed have included transformer-related assets as the focal point of the funding request.

The one remaining notable application for ICM funding was that of Toronto Hydro-Electric System Ltd.'s[4] three year application for 2012 to 2014 inclusive. While Toronto Hydro proposed a number of unique approaches to the Board's ICM policy in effect at the time, the two most notable that were approved were the multi-year approach and the request for multiple projects encompassing most of the eligible incremental capital available to the company in each of the three years.[5]

In its decision, the Board determined that both proposed approaches for incremental funding were approved in light of Toronto Hydro's unique circumstances.[6] While the Board approved funding for both the 2013 and 2014 rate years, it stated its expectation that future IRM filings will only be for one year, unless there are appropriate circumstances that justify a multi-year approach to IRM.

Following are a number of excerpts from the Board's decision:

> *The Board finds that on a case by case basis, some projects that might be characterized as "business as usual" may be eligible for ICM. The criteria in the Reports do not require that capital expenditures are on an "emergency or urgency basis" but rather, that the work must be undertaken and that the existing capital in the rebasing year is insufficient to do so. The Board rejects the notion that projects that might be "routine" or "business as usual," are ineligible categorically for an incremental capital module […]*[7]
>
> *The Board's Supplemental report (p. 31) does refer to unusual circumstances but does not refer to unanticipated circumstances. The Board finds that the aging infrastructure and the associated capital needs of the magnitude faced by*

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[3] Chapter 3 of the Filing Requirements for Transmission and Distribution Applications (Incentive Regulation Mechanism)
[4] EB-2012-0064: This proceeding took place in two phases with Phase 1 reviewing 2012 and 2013, and Phase 2 reviewing 2014.
[5] It should be noted that for the 2012 rate year, no eligible capital was available once the Board established that Toronto Hydro's non-discretionary capital budget for the 2012 calendar year did not exceed the materiality threshold for that year. Therefore, no ICM recovery was approved for that year.
[6] In its Part 1 decision for the 2013 test year, the Board disallowed ICM treatment for certain planned capital projects, although the majority of capital projects and costs were approved. (Partial Decision and Order, April 2, 2013). The 2014 capital program was subject to a Settlement Agreement subsequently approved by the Board (Transcript, Vol. 11, December 19, 2013, pg. 5, ll. 3-8).
[7] EB-2012-0064, Partial Decision and Order, April 2, 2013, pg. 18

THESL can be considered "unusual" in the broader context of Ontario utilities […][8]

The Board notes that most previous ICM applications approved by the Board have been for one or a few discrete large projects. While the Board will not adopt the suggestion of some parties that each project put forward by THESL should meet the overall materiality threshold, the Board does not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget.[9]

In summary, as of the end of the 2014 rate year, the scope of the Board's ICM policy, as implemented in its decisions (aside from the unique circumstances of Hydro One and Toronto Hydro), have involved discrete non-discretionary capital projects that have a significant influence on the operations of a distributor, that are not limited to extraordinary or unanticipated investments, and whose allowable cost is limited to the difference between the non-discretionary capital budget and the materiality threshold.

The above experiences, along with the outcomes of the June 25 Working Group session, and the impact of the adoption of the Renewed Regulatory Framework with its emphasis on planning, have informed the content of this ACM Report; specifically, why requests for incremental capital funding should be proposed much earlier in a distributor's planning horizon, and what criteria (both new and existing), should be established, revised or maintained given this shift.

The next section discusses the impact of the adoption of the Renewed Regulatory Framework.

[8] *Ibid., pg. 18*
[9] *Ibid., pp. 18-19*

3 The Need for a Revised Incremental Capital Module Mechanism

The Board's RRFE Report represented a significant evolution of the approaches for rate regulation of the sector. In the RRFE Report, the Board established three rate-setting options for electricity distributors:

- Price Cap Incentive Rate-Setting ("Price Cap IR"), under which rates are rebased through a cost of service application followed by four years of rate adjustments through an annual formulaic price cap adjustment;

- Annual Incentive Rate-setting ("Annual IR"), whereby the distributor files for annual rate adjustments under the price cap formula, without rebasing, but subject to rates being adjusted by the highest stretch factor; and

- Custom Incentive Rate-setting ("Custom IR"), whereby the distributor proposes a plan to be effective for rate setting for five years, and with an approach that the distributor feels would reflect its capital and operating needs more appropriately than would the other approaches.

The subsequent *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379)* ("the Price Cap IR Report"), issued November 21, 2013 and updated December 4, 2013, provided further details on these three rate-setting mechanisms.

A risk for any form of regulation is the emergence of unintended consequences as a result of regulated entities responding to incentives that emerge inadvertently from the regulatory framework within which they operate. One such tension that has been observed is the regular pacing of capital projects at certain points within the rate-setting cycle. There appears to be a tendency for capital projects, particularly major ones, to be clustered around the test year when the distributor rebases its rates through a cost of service application. In subsequent years, capital expenditures and additions may be substantially less than the levels in the bridge and test year(s), possibly as a means of managing capital and operating expenses relative to the often smaller changes in revenues in those years where a price cap formula is used to adjust rates.

The concern is that this volatility (i.e. the "roller coaster" effect) of capital investments to fit the rate-regulation schedule does not necessarily align with when the investments should be made under prudent asset management practice. While a significant portion of capital investment may be "routine" (i.e., fairly predictable and levelized), some volatility and lumpiness is not uncommon. The nature of major capital projects, such as transformer station builds or replacement, is one reason that some "bumps" in capital spending may be unavoidable. However, while timing these around when the rate base is "reset" in a cost of service application provides greater assurance of recovery of the investments (if approved), such clustering of projects is often not optimal from an asset management perspective, nor desirable from a rate impact perspective.

As the Board has identified in the RRFE Report and other documents[10], the Board is of the view that the industry would be better served by a more disciplined approach to capital planning. In recent years, the Board established expectations that distributors conduct and file Asset Management Plans as part of cost of service applications. This has evolved into the current Distribution System Plan ("DSP") requirement. Under the RRFE, distributors are also expected to provide documentation on their efforts to engage customers on the necessary capital and operating costs and on the associated cost consequences that will be ultimately impacting customers.

Incenting distributors to adopt a longer term planning horizon for capital and operating projects should enable the distributor to optimize its resource requirements (financial, human and equipment) so as to be able to efficiently and effectively serve existing customers while planning for and making investments to serve future needs in a timely manner.

Accordingly, the Board has decided to advance the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IRM term) to the preceding cost of service application in which a distributor is required to file a five year Distribution System Plan encompassing the cost of service test year and the four subsequent incentive rate-setting[11] ("IR") years.

As will be explained further in section 5 of this ACM Report, the opportunity for requests for review and approvals of incremental capital during the IR term will be maintained for projects that were unanticipated at the time of the development of the Distribution System Plan, or for projects anticipated but for which sufficient rationale was not available at the time of the DSP to establish need and prudence.

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[10] e.g., *Filing Requirements for Distribution Rate Applications – Chapter 5 - Consolidated Distribution System Plan Filing Requirements*.
[11] *This Report uses Incentive Regulation Mechanism ("IRM") and Incentive Rate-setting ("IR") interchangeably.*

4 The Revised Capital Module Policy

In light of the Board's expectations, as signalled in the RRFE Report and associated documents, the Board is establishing the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module (or "ACM").

The review and approval process of the rate riders intended to implement cost recovery of approved ACM projects, will be maintained as part of the IR application process.

This approach adapts and adds to the ICM mechanism**.** Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.

When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should reduce incentives for clustering capital projects around the rebasing year. Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle. While some lumpiness of capital projects may be unavoidable (particularly for distributors with smaller rate bases, where a single project such as a transformer station build or replacement would be a major fraction of any annual capital budget), the Board expects that the volatility that has been observed in some cost of service applications in recent years will be reduced.

The ACM approach will also assist in large part to preserve the regulatory efficiency of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides greater assurance of recovery for prudent and appropriately prioritized capital projects regardless of when the investments might be made.

The Board would also expect improved performance with respect to capital forecasting both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.

Following any approvals in a cost of service application, the distributor would still have to file information in the applicable IR application to confirm that the ACM is on schedule to be completed as planned, that the costs of the projects have not significantly changed from the original forecast, and to determine the appropriate rate riders for approval.

In general, the details and need for a project that has received ACM approval in a previous cost of service application should not need to be re-examined in an IR application; however, if the forecasted costs (or timing) are significantly different than what was in the DSP, the onus is on the distributor to support the changes.

In particular, if costs are 30% (or more) above what was documented in the DSP, the distributor has the option of seeking approval for the incremental costs but would typically treat the project as a new ICM and re-file the business cases and other relevant material in the applicable IR year. It is expected that the Board will include this condition as part of the ACM approval. This would provide the applicant and parties an opportunity to argue for a different (higher or lower) percentage depending on the nature of the project.

If costs are less than 30% above what was documented in the DSP, the distributor should still explain the need for the increased costs, whether and how re-prioritizing of capital projects has been considered, how impacts on the rates and bills of the distributor's ratepayers have been taken into account and finally, whether the project is still the best option. Any changes in project scope must be clearly explained and justified.

If the in-service date has been delayed to the following rate year (or beyond), distributors should identify this fact in the earliest possible IR application and confirm in which IR application the distributor expects to seek to commence funding for the project. Funding shall not commence for any projects that are not forecasted to be in service during the subject IR year.

Following a cost of service application, per the current ICM policy (which is now extended to ACMs), the actual costs and the recoveries would be reviewed for any material discrepancies. If there are significant variances between the revenue requirement based on actuals and the revenues collected through the ACM rate riders, the Board may decide to true up any differences. The following sections provide further discussion and details on ACM and ICM approvals during the IR period.

The Board will retain an incremental capital module (or "ICM") for the IR years for projects not included in the DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence. Further information on the scope of the revised ICM are outlined in section 5 below.

4.1 New and Revised Criteria

The Board considers that the current ICM approach has been tested and, most importantly, is serving the purpose for which it is intended. The ACM concepts build on this experience and takes advantage of the information available in the DSP that is filed as part of a cost of service application.

Applications for requests for determination of the need and prudence for proposed projects to be included in ACMs as identified and documented in the DSP will use similar criteria as is required currently for an ICM project as part of an IR application. However, in this regard there have been some revisions to the current ICM criteria, as well as the adoption of new criteria, that will apply to both ACMs and ICMs. These are set out below. Criteria that will continue to apply unchanged to both an ACM and ICM are outlined in section 4.2.

4.1.1 The Adoption of the "Discrete" Project Criterion

The Board is of the view that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs. This would apply to both ACMs and ICMs going forward.

The Board will make a determination on whether projects are discrete on a case by case basis. However, there must be a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year), and the Custom IR method. The use of an ACM is most appropriate for a distributor that:

- does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
- is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or
- is not proposing to use the entire eligible incremental capital envelope available for a particular year.

4.1.2 The Adoption of a Preliminary Materiality Threshold Calculation

The Board will not require distributors to forecast final details of the ICM formula (i.e. the materiality threshold) for each of the IR years at the time of the cost of service application. Instead, any approvals sought at the time of the cost of service application will be based on need and prudence. The final assessment on whether or not the quantum of the approved project fits within the maximum allowable capital amount (i.e., the total eligible incremental capital amount) will take place at the time of the applicable Price Cap IR application. If the costs of the project(s) exceed the total available envelope for the subject year, the amount allowed for recovery will be limited to the maximum allowable capital amount.

However, **as part of the cost of service application, distributors must provide a preliminary estimate of the materiality threshold value (and consequently, the total eligible incremental capital amount) for the subject year in which the proposed project is planned to enter service in order to provide the Board with a degree of certainty that the distributor will meet the threshold criteria**. As noted above, the quantum of the threshold and the maximum allowable capital amount for the applicable year will be confirmed at the time of the IR application.

The Board has outlined in section 6 of this ACM Report a preliminary threshold calculation to be used for each IR year at the time of the COS application based on the current ICM formula. The Board is not making any substantive changes to the main ICM formula at this time. Some minor adjustments to the description of certain variables have been made to accommodate the timing of the preliminary threshold calculation. The Board intends to continue to review the formula and will determine a course of action, if any, in the future.

4.1.3 The Elimination of the Non-Discretionary Criterion

The Board is of the view that the availability of incremental capital funding during the IR term should no longer be limited to non-discretionary projects. **Any discrete project (discretionary or otherwise) adequately supported in the DSP is eligible for ACM funding subject to capital funding availability flowing from the formula results. The same approach shall apply going forward to new projects proposed as ICMs during the Price Cap IR term.**

With the establishment of a requirement to file a five year DSP, distributors will be expected to develop well-paced plans to maximize the efficiency and effectiveness of their distribution systems in serving customers, and smooth rate impacts where possible. The current approach of limiting incremental funding to non-discretionary projects could inappropriately incent a distributor to time certain projects in their DSP so that funding is available. By expanding the incremental funding to both discretionary and non-discretionary projects, distributors will have the opportunity to develop their most robust plans without limiting their opportunity for incremental funding.

Distributors are required to identify the total annual capital budget for each of the five years as part of their DSP, at the time of the cost of service application. This amount will now be used in the calculation of the total eligible incremental capital amount for any given year (as opposed to the current policy that requires the non-discretionary component to be used as the starting point in the calculation). The same approach shall apply going forward for new projects proposed as ICMs during the IR term.

4.1.4 The Adoption of a Means Test

The Board is of the view that establishing a means test would be prudent in qualifying distributors for incremental capital funding. Any distributor approved for an ACM in its most recent cost of service application must file its most recent calculation of its regulated return (RRR 2.1.5.6) at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. **If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.** Therefore, any approvals provided for an ACM in a cost of service application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The same means test shall also apply going forward for new projects proposed as ICMs during the Price Cap IR term.

While a means test that doesn't allow incremental funding if a distributor is earning more than its Board-approved ROE may be a barrier to a distributor seeking efficiency improvements during the IR term, a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective. Distributors will have the option of explaining any overearnings.

4.1.5 Revisions to the Eligibility Criteria

The eligibility criteria to recover amounts that are incremental to capital investment needs were first set out in section 2.5 of the July 14, 2008 Report of the Board.

The following are the current definitions of Materiality, Need and Prudence as they apply to ICMs.

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (no necessarily least initial cost) for ratepayers.

In order to reflect the new and revised criteria discussed above and to further clarify the purpose of the materiality threshold calculation, the Board has made revisions to the formal eligibility criteria applicable to both ACMs and ICMs.

Most notable of the changes is the Board's decision to revise the reference to amounts (i.e. referring to projects) "exceeding" the Board-defined materiality threshold. While this language has been used in the Board's past reports and in decisions, it has caused much confusion as to its meaning. Specifically, approved amounts do not "exceed" the materiality threshold, rather they must fit within the total eligible incremental capital, which is the difference between the total capital budget for the subject year and the result flowing from the materiality threshold calculation.

Any reference to "exceeding" the Board-defined materiality threshold is therefore in reference to the total capital budget, the starting point to the calculation of the total eligible incremental capital amount. Therefore, the materiality test would be met if there is a positive variance between a distributor's capital budget (typically the budget included in the previous cost of service application) and the Board-defined materiality threshold. The distributor would therefore be eligible to identify projects for ACM or ICM treatment if its capital budget for the subject year exceeds the Board-defined materiality threshold. The materiality threshold is in effect a capital expenditure threshold which serves to demonstrate the level of capital expenditures that a distributor should be able to manage with its current rates.

In addition, the Board has adopted a project-specific materiality threshold, as identified in the Toronto Hydro decision.[12]

Distributors proposing amounts for recovery by way of an ACM or ICM must meet all three of the following criteria, and their sub-parts.

Criteria	Description
Materiality	A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	The distributor must pass the Means Test (as defined in this ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

[12] *EB-2012-0064, op.cit. pp. 18-19. Specific projects were not approved on the basis that they were minor expenditures in comparison to the overall capital budget.*

4.2 Current Criteria That Continue to Apply Unchanged

Distributors must file, at the time of the cost of service application, a description of the actions the distributor would take in the event that the Board does not approve the ACM proposal. Similarly, distributors must file comparable information for any ICM requests at the time of the IR application.

Distributors must also include a discussion on any offsets associated with each incremental project for which ACM or ICM treatment is proposed due to revenue to be generated through other means (e.g. customer contributions in aid of construction), at the time of the cost of service application, along with an estimate of the revenue requirement impact associated with those offsets. The final offset amounts, if any, would be confirmed at the time of the IR application.

The ACM and ICM are only available to electricity distributors opting for Price Cap IR. The ACM/ICM approach is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold defined below, while allowing the distributor to obtain necessary recovery of capital investments on a planned and prioritized basis over the whole IR period. Applicants should note that custom approaches to rate-setting should be addressed through selecting the Custom IR option, not by customizing an ACM or ICM proposal. The ACM/ICM approach is not available to distributors filing under the Annual IR plan.

Finally, the Board notes that ACM and ICM mechanisms are intended to provide utilities with an opportunity to establish reasonable rate impacts for customers. In fact, with the longer-term planning horizon of the DSP and of engaging customers on their needs, expectations and willingness to pay, the Board continues to expect that distributors will exhibit greater discipline on the pacing and prioritization and hence on consistency in the levels of capital expenditures over time. At the same time, these options increase the assurance of recovery from when the investments are made and go into service, and the Board expects that distributors will take this into consideration in planning and managing their capital programs.

5 The Scope of the Incremental Capital Module

While the Board has advanced the opportunity for distributors to apply for early identification of projects during the cost of service application to be included for ACM treatment during the subsequent Price Cap IR terms, **the Board will retain the availability of new ICM requests in each of the IR years, with the same scope as exists with the current approach.** ICM projects will not be limited to those that are unanticipated, but will be subject to the revised criteria discussed in this paper such as the elimination of the non-discretionary requirement and the means test. The Board may revisit the criteria for the ICM in the future as experience is gained with the use of the ACM.

As one example of a situation that could trigger a capital project which may be identified in the DSP, but may not contain sufficient detail to address need and/or prudence at the time of the cost of service application, would be where a distributor is required to make a significant investment during its Price Cap IR term based on the outcome of a Regional Plan. The Regional Plan investment might not have been detailed sufficiently at the time of the DSP and cost of service application, but could become a significant capital project in which the distributor may have to invest during the later period of the IR term. ICM treatment would allow for recovery of costs beginning when the investment is made and goes into service, rather than awaiting the next cost of service application to rebase rates.

ICM proposals as part of Price Cap IR applications will result in a more involved Price Cap IR application. Since the nature and need for the ICM-qualifying project has not been pre-identified or pre-tested, all such information would need to be detailed in the Price Cap IR application.

For distributors currently under incentive rate-setting, the current scope, criteria and definitions of the ICM shall continue to apply, subject to the revisions noted in this paper. For example, the elimination of the non-discretionary criterion will apply not just to ACMs going forward, but also to all ICMs that may be filed by distributors currently on incentive rate-setting.

6 Materiality Threshold Calculation

The ICM materiality threshold is discussed in section 2.3 of the Supplemental Report. The Board determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1 + g)\right)\right] + 20\%$$

This formula will continue to apply for IR years. The application of the formula for the final calculation to be provided at the time of approval of ACM rate riders, and ICM projects and associated rate riders in Price Cap IR applications remains unchanged.

This formula will also be used for the preliminary materiality threshold calculation to be provided at the time of an ACM request in a cost of service proceeding. The Board has made minor revisions to the definitions of the variables for the preliminary calculation to address the advanced timing of an ACM request, but does not expect that these changes will significantly alter the results from the previous formula. Appendix B of this ACM Report summarizes the definitions for both the preliminary and final calculations.

As noted earlier in this ACM Report, the Board intends to continue to review the components and applicability of the formula and will determine a course of action, if any, in the future.

Definitions of the terms are as follows:

RB is the rate base in the distributor's most recent cost of service application. This will be the Board-approved rate base in the most recent cost of service application for new ICM requests and for ACM rate rider approvals in a Price Cap IR application. For the preliminary materiality threshold calculation for a distributor is applying for an ACM in a cost of service application, the distributor should use its proposed rate base.

d is the depreciation expense approved in the distributor's most recent cost of service application. This will be the Board-approved depreciation expense in the most recent cost of service application for ICM requests and for ACM rate rider approvals in a Price Cap IR application. For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its proposed depreciation expense.

The value for g is the percentage difference in distribution revenues between the most recent complete year and the approved base year, for ICM requests and for ACM rate rider approvals in a Price Cap IR application. In the first or second IR years following rebasing, a distributor may not have a complete year of data following the cost of service base year. Therefore, for these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year.

For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its forecast distribution revenues as the base year and compare those with the most recent complete year.

Some concerns with respect to the current definition of the growth rate g have been identified previously, as it is derived comparing weather normalized (i.e., last Board-approved) to non-weather-normalized (i.e. actuals). This matter may be reviewed as part of any broader formula review in the future. For now, the Board does not view this discrepancy as materially affecting the formula results.

PCI is the price cap index, calculated as $PCI = IPI - X - stretch\_factor$ as defined in the Price Cap IR Report. Under the Price Cap IR, $X = 0$. For ICM requests and ACM rate rider approvals in a Price Cap IR application, distributors should use the most recently approved IPI and stretch factor as placeholders in their initial filings, and then update that information during the course of the proceeding once the Board establishes updated parameters for the subject year. For the preliminary materiality threshold calculation for a distributor applying for an ACM in a cost of service application, the distributor should use its most recently approved stretch factor and the most current version of the IPI.

The following is a numerical example of a preliminary calculation of a materiality threshold value for an IR year, but calculated at the time of the cost of service application.

Assumptions	Proposed Rate Base	RB	\$100 million
	Proposed Depreciation Expense	d	\$5 million
	Growth (forecasted dx revenues compared to dx revenues from most recent complete year)	g	(0.01275)
	Current IPI at the time of the application	IPI	1.7%
	Most recently approved Stretch Factor at the time of the application	$stretch\_factor$	0.4%
	Price Cap Index	$PCI = IPI - stretch\_factor$	1.7% - 0.4% = 1.3%
Calculation	$1 + \left(\frac{100{,}000{,}000}{5{,}000{,}000}\right) \times \left(0.01275 + 0.013 \times (1 + 0.01275)\right) + 0.20 = 171.8315\%$		
Result	The materiality threshold (Capex/Depreciation) is 1.718315 or 171.8315%. That is, given the assumptions in this example, the Board would expect the distributor to be able to fund capital expenditures (Capex) up to \$8.591575		

	million ($5 million X 1.718315) during the Price Cap IR adjustment following rebasing before being eligible to apply to recover amounts for incremental capital expenditures for qualifying ACM capital projects.

Following the above calculation, the total incremental capital amount can then be calculated for each IR year by subtracting the threshold result from the proposed capital budget identified in a distributor's DSP for each of the four years.

For ACM requests at the time of a cost of service application, this preliminary threshold result may be used for each of the four IR years as an estimate for purposes of providing the Board some degree of comfort that a distributor has a capital budget that exceeds the materiality threshold. The preliminary calculation will demonstrate that the distributor is likely to be eligible to apply for incremental capital before the Board expends efforts in assessing need and prudence for the project.

6.1 The Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amounts sought for recovery should be capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula set out above, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. Section 4 of this ACM Report clarifies the reference to capital in excess of the materiality threshold.

The determination of the maximum allowable incremental capital amount has not changed from the guidance provided in the Board's recent Filing Requirements other than to remove the reference to non-discretionary. **It is now determined by taking the difference between the forecasted <u>total</u> capital expenditures for a subject year and the materiality threshold for that year.**

If the forecasted total capital expenditures identified in a Price Cap IR application, are higher than what the distributor documented in its DSP in its previous cost of service application, the distributor needs to document the increases and the reasons for these. This approach is unchanged from the current ICM policy.

For clarification, the Board's ICM models refer to a "threshold capex". This refers to the dollar value associated with the materiality threshold result and is subtracted from the total forecasted capital expenditures to determine the maximum amount eligible for recovery, for the applicable year.

7 Filing Requirements

Section 2.5.2 of Chapter 2 of the Filing Requirements contains additional information on filing requirements related to capital expenditures. In addition, Chapter 5 of the Filing Requirements deals with the 5-year Distribution System Plan, which will normally be dealt with as part of a cost of service application. An ACM/ICM is an application for recovery of needed and reasonable expenditures for a capital project, and a distributor making an application for an ACM/ICM should reflect the appropriate documentation as detailed in these sections of the Filing Requirements.

7.1 Revenue Requirement Calculation

Distributors must file the calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each approved ACM or proposed ICM, in the applicable Price Cap IR application. Distributors must also identify any revenue requirement offsets associated with each incremental project due to revenue to be generated through other means (e.g. customer contributions in aid of construction).

When calculating the revenue requirement associated with either an approved ACM or an ICM proposal at the time of the Price Cap IR application, a distributor should use the following parameters and methodologies.

7.1.1 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.[13] The Board adopted this as a clarification to the policy on ICM in the Filing Requirements. This approach is unchanged for the new ACM/ICM policy.

[13] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order*, p. 15. This is appropriate, as the full year of depreciation expense will be explicitly reflected in the determination of the rate base and revenue requirement in the cost of service application for the following test year. Full year treatment of a ICM capital addition in the last year before rebasing would increase the probability of a true-up being required when the actual capital project costs are reviewed and included in rate base to determine rebased rates.

7.1.2 Working Capital Allowance

A distributor shall use the WCA approach approved by the Board in the distributor's most recent cost of service application when calculating the revenue requirement associated with the ACM/ICM.

7.1.3 Cost of Capital

In the December 11, 2009 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084) the Board confirmed the continuation of a deemed 60/40 debt-equity ratio. A distributor filing for ACM or ICM rate riders shall use the cost of capital parameters approved by the Board in the distributor's most recent cost of service application when calculating the revenue requirement associated with the incremental funding.

7.1.4 Taxes / PILs

Since currently known legislated tax changes from the level reflected in the Board-approved base rates for a distributor will be reflected in the rate adjustments for Price Cap IR, a distributor filing for ACM or ICM rate riders should apply the current tax rates for calculating the revenue requirement associated with the incremental funding.

7.1.5 Rate Riders

Distributors must file the calculation supporting the proposed rate riders to recover the incremental revenue from each applicable customer class, and the rationale for the proposed approach.

7.1.6 Bill Impacts

Distributors must also provide bill impacts in a Price Cap IR application and the Board notes that its rate generator model used by most distributors in a Price Cap IR application contains detailed bill impacts for all classes.

7.2 Need and Prudence

A distributor requesting relief for incremental capital (both ACMs and ICMs) must include comprehensive evidence to support the need. If the ACM request is proposed as part of a cost of service application, it is expected that most of the following information would be included as part of the DSP, in any event:

- A preliminary threshold calculation demonstrating that there is a reasonable expectation that the final materiality threshold test at the time of the IR application will be met and that the amounts will have a significant influence on the operation of the distributor;

- A description of the proposed capital projects and expected in-service dates and their costs. In general, this would be satisfied by the filing of a business case and engineering study, as appropriate, for each capital project for which the applicant is seeking ACM or ICM approval;

- Details, by project, for the entire capital spending plan for the subject year. This analysis includes projects that are not being proposed for ACM or ICM treatment.

- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers; and

- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in significant part, included in base rates or being funded by the expansion of service to include new customers and other load growth).

In the Price Cap IR application for the year in which the capital project(s) will go into service and the applicant is seeking to commence recovery through rate riders, the distributor should provide updated, current information with respect to the above for any approved ACMs for any material changes from what was reflected in the DSP.

In the case of an ICM proposal for recovery of an unanticipated capital project, or for a project for which a distributor did not have sufficient information to address need and prudence at the time of the cost of service application, this will be the first time that the distributor is providing such evidence. Therefore full and complete details of the project(s) must be filed, as is the current ICM policy and practice.

7.3 Confirmation of Cost and Timing

If the timing of an approved ACM project is advanced or deferred from when the distributor expected that it would incur the project (in the DSP reviewed in its cost of service application), the distributor must provide an explanation on the reasons for the change in timing, and on how the change in pacing and prioritization may have affected its five-year DSP overall, at the earliest opportunity as part of a Price Cap IR application.

7.4 Reporting Requirements

At the time of the next cost of service or Custom IR application, a distributor will need to file calculations showing the actual ACM/ICM amounts to be incorporated into the test year rate base. At that time, the Board will make a determination on the treatment of any difference between forecasted and actual capital spending under the ACM/ICM, if applicable, and the amounts recovered through ACM/ICM rate riders and what should have been recovered in the historical period during the preceding Price Cap IR plan term. Where there is a material difference between what was collected based on the approved ACM/ICM rate riders and what should have been recovered as the revenue requirement for the approved ACM/ICM project(s), based on actual amounts, the Board may direct that over- or under-collection be refunded or recovered from the distributor's ratepayers.

7.5 Accounting Treatment

The distributor will record eligible ACM/ICM amounts in Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, subject to the assets being used or useful (i.e. in service). For incremental capital assets under construction, the normal accounting treatment will continue as construction work in progress ("CWIP") prior to these assets going into service and hence being eligible for recording in the 1508 sub-account listed below.

In its July 18, 2014 Filing Requirements applicable to 2015 cost of service applications for electricity distributors, the Board provided further guidance on the recording of amounts related to approved ICM projects and revenues received from approved rate riders.[14] Distributors shall record actual amounts in the following sub-accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures;
- Account 1508 – Other Regulatory Assets, Sub-account Depreciation Expense;
- Account 1508 – Other Regulatory Assets, Sub-account Accumulated Depreciation; and
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues.

[14] *Filing Requirements for Distribution Rate Applications – 2014 Edition for 2015 Rate Applications*, July 18, 2014, section 2.5,2.7: Addition of ICM Assets to Rate Base

The distributor shall also record monthly carrying charges in the following sub-accounts. Carrying charge amounts are calculated using simple interest applied to the monthly opening balances:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, Carrying charges.
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges;

The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period as published on the Board's web site. All of these sub-accounts should be used for both approved ACM and ICM projects. If the Board approves the true-up of any variances for ACM/ICM projects at the next cost of service application, the recalculated revenue requirement relating to the actual ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period, plus the carrying charges in the respective sub-accounts. These variances would then be refunded to, or collected from, customers through a rate rider.

7.6 Rate Models

The revised Capital Module work form (applicable to ACMs and ICMs) supporting the IRM Rate Generator model will assist distributors in calculating the distributor's final threshold at the time of the IR application. The distributor will then tabulate the value of its eligible investments and compare this to the threshold result to determine the amount that would be eligible for recovery. The tabulated revenue requirement will then be converted into class specific rate riders.

The work form has also been altered so that it can calculate the preliminary threshold and identify qualifying capital projects from the distributor's DSP for inclusion in the ACM request in the cost of service application.

Appendix A

The Revised Capital Module Policy

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the Board may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Appendix B
Materiality Threshold Calculations

The following table explains the variables used to determine the preliminary materiality threshold, which will be updated in the Price Cap IR application to deal with the implementation of an ACM or ICM project and associated rate riders.

General Formula:		$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1 + g)\right)\right] + 20\%$	
Parameters		**Preliminary Calculation for proposed ACM-qualifying capital projects (as part of a Cost of Service Application)**	**Final Calculation for pre-qualified ACM projects or for proposed ICM projects (as part of a Price Cap IR Application)**
Rate Base	RB	In its application, the utility should use its proposed test year rate base.	The distributor should use the approved rate base from its last cost of service application.
depreciation	d	In its application, the utility should use its proposed depreciation expense for the test year.	The distributor should use the approved depreciation expense from its last cost of service application.
Growth	g	g is always to be expressed as an annual growth rate. Growth should be calculated based on the percentage difference in distribution revenues between the forecast distribution revenues for the test year and the distribution revenues from the most recent complete year.	g is always to be expressed as an annual growth rate. Growth should be calculated based on the percentage difference in distribution revenues between the distribution revenues from the most recent complete year and the distribution revenues from the most recent approved test year. In the first and second IR years following rebasing, a distributor will likely not have a complete year of data following the cost of service base year. For these years, the growth factor may be updated to the difference between the Board approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year.
Price Cap Index	PCI	Distributors should use the Price Cap Index $(IPI - stretch\_factor)$ from its most recent Price Cap IR application.	Distributors should use the Price Cap Index from its most recent Price Cap IR application as a placeholder for the initial application filing. This information should be updated if updated parameters become available during the course of the proceeding.

Appendix C
List of ICM Decisions (to date)
Issued under the Board's previous policy

File Number	Applicant	Decision Date
EB-2008-0187	Hydro One Networks Inc.	May 13, 2009
EB-2008-0205	Oshawa PUC Networks Inc.	June 10, 2009
EB-2010-0104	Oakville Hydro Electricity Distribution Inc.	March 14, 2011
EB-2010-0130	Guelph Hydro Electric Systems Inc.	March 14, 2011
EB-2011-0178	Kingston Hydro Corporation	April 19, 2012
EB-2011-0207	Woodstock Hydro Services Inc.	March 22, 2012
EB-2011-0160	Centre Wellington Hydro Ltd.	March 22, 2012
EB-2011-0173	Hydro Hawkesbury Inc.	May 3, 2012
EB-2012-0064	Toronto Hydro Electric System Limited	April 2, 2012
EB-2012-0124	Festival Hydro Inc.	April 4, 2013
EB-2013-0166	PowerStream Inc.	February 20, 2014
EB-2013-0178	Wellington North Power Inc.	March 13, 2014
EB-2013-0127	Espanola Regional Hydro Distribution Corporation	March 13, 2014

Report of the OEB

EB-2014-0219

New Policy Options for the Funding of Capital Investments: Supplemental Report

January 22, 2016

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1 Executive Summary

This Report outlines the OEB's policy with respect to the matters addressed in a supplemental phase of the consultation on *New Policy Options for the Funding of Capital Investments* (EB-2014-0219).

The OEB engaged KPMG and formed a working group composed of utility and stakeholder representatives. The OEB has considered the work of KPMG and OEB staff, and the feedback provided by working group participants. In this Supplemental Report the OEB has determined that:

- No changes will be made to the manner in which the OEB applies the half-year rule in a test year and its persistence over the incentive rate-setting (IR) term.

- The materiality threshold formula will be modified as follows:
    - A multi-year formula
    - An annualized growth factor
    - A dead band of 10% (down from the previous 20%)
    - Use of the stretch factor assigned to the middle cohort (currently 0.3%) for every distributor for the determination of the materiality threshold, irrespective of the actual stretch factor at any one point in time

This Supplemental Report augments the policies adopted in the September 2014 ACM Report, and must be read in conjunction with that report. The changes adopted herein will be reflected in the Filing Requirements applicable to cost of service and IR applications when the Filing Requirements are next updated by the OEB. The ACM excel model used by the OEB has been updated to reflect the changes adopted in this Supplemental Report.

2 Background

The OEB initiated this policy review in 2014. The review considered two aspects on the OEB's approach to funding capital additions:

- The effect of the half-year rule on test year capital additions for the intervening years between rebasing applications

- The introduction of a new funding mechanism that would enable review during a cost of service application for the need and prudence of any incremental capital module (ICM) funding requests for discrete projects that are part of a distributor's Distribution System Plan, and that are planned to come into service during the IR period (i.e., the Advanced Capital Module (ACM))

On September 18, 2014, following work by OEB staff and a consultation with a working group of utility and stakeholder representatives, the OEB issued its *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the ACM Report).

In the ACM Report, the OEB established the Advanced Capital Module. This is a new mechanism to assist electricity distributors in their progress towards developing and justifying a long-term strategy for delivering distribution services that their customers value and that reflect manageable rate impacts over the long term. The ACM advances the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IR term) to the preceding cost of service application in which a distributor is required to file a five year Distribution System Plan (DSP) encompassing the cost of service test year and the four subsequent incentive rate-setting years.

The OEB retained an incremental capital module (the ICM) for the IR years for projects not included in a DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence.

The ACM Report also revised certain of the existing criteria and established new criteria to assist with the testing of incremental capital requests (under both an ACM and ICM).

In the ACM Report, the OEB did not make a determination with respect to the elimination of the effect of the half-year rule on test year capital additions for the IR years. There were other matters on the ACM/ICM approach which were considered during the initial work, particularly related to the materiality threshold formula, which remained unresolved as well. The OEB indicated that it would continue to review these matters. This Supplemental Report provides the result of that additional review.

KPMG was retained to assist OEB staff and a new working group was established for this latest policy review. In addition to continuing the assessment of the impact of the half-year rule, the working group and KPMG reviewed specific components of the ICM materiality threshold formula.

KPMG was specifically tasked with reviewing two rate making issues:

- The half-year rule
    - A jurisdictional review of the treatment of new capital additions in rate base and revenue requirement (i.e., the use of the half-year rule or other approaches)
    - The adequacy of price-cap adjustments for funding capital investments under the OEB's Price Cap IR regime in which the half-year rule persists during the term
- The materiality threshold formula
    - A review of the appropriateness of the current definition of the growth (g) factor
    - A review of the appropriateness of the current definition of the dead band due to any impacts arising from the adoption of the following on the suitability of the materiality threshold formula and its parameters
        - Total Factor Productivity (TFP) versus the use of the previous Partial Factor Productivity (i.e. OM&A benchmarking) for deriving the productivity adjustment under IR
        - International Financial Reporting Standards (IFRS)

- Related to another project, a jurisdictional review of how the Working Capital Allowance (WCA) is established for rate regulation.

The research on the WCA is related to the *Policy Review of Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance: A Review of Cash Working Capital Funding (EB-2014-0198),* and was considered in the consultation of that project. It has no further impact on this project.

The working capital portion of the KPMG report was issued in draft form on June 3, 2015 along with the OEB's letter setting out the new default WCA. That excerpt has now been finalized with no changes and is included for completeness in KPMG's final report,

New Policy Options for the Funding of Capital Investments: EB-2014-0219, supporting this supplemental phase of the consultation and can be found on the OEB's website, at *http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0219/KPMG_Report_EB-2014-0219_20150626.pdf*.

3 The Half-Year Rule

The application of the half-year rule has been the subject of much discussion since it was first adopted by the OEB in the context of an incentive rate-setting mechanism. Distributors have been generally concerned that the persistence of the half-year rule into an IR period deprives them of half of the depreciation and return on their test year investments during the IR term and that this effect has been exacerbated by the extension of the IR term from four to five years under the Renewed Regulatory Framework for Electricity (the RRFE).

This section reviews and assesses the current OEB policy. For the reasons set out below, the OEB has determined that no changes will be made to the manner in which the OEB applies the half-year rule in a test year and its persistence over the IR term.

3.1 Test Years

The current OEB policy, established in the OEB Report on the *2006 Electricity Distribution Rate Handbook*, allows for recovery of a half-year depreciation and a half-year of the return on capital for the year that capital assets enter service, while the full year's depreciation and cost of capital is recovered on assets already in service.[1] This policy was adopted as most new capital additions only come into service part-way through the year. Since ratepayers only receive the benefit of the capital additions once the assets enter into service, earning a full year's depreciation and return would over-compensate the utility relative to the benefit that ratepayers receive during that first year.

Specifically, the half-year of the return on capital is accomplished through the calculation of the average net book value of in-service assets during the year, calculated as the average of opening (January 1) and closing (December 31) balances. For depreciation expense, one-half of the annual straight-line depreciation expense is allowed in the year that assets enter service. In subsequent test years, the full annual depreciation expense for the assets is reflected in the revenue requirement and recoverable in rates, until the last year of that asset class' expected useful life, when the final half-year of depreciation expense is recovered.[2]

For electricity distributors, the OEB has employed this default approach as a means of ensuring that the full year's depreciation and return on capital are not included in rates

[1] *Report of the Board: 2006 Electricity Distribution Rate Handbook (RP-2004-0188)*, May 11, 2005, p. 15 (regarding the ½ year treatment for new in-service additions).
[2] *Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – Chapter 2: Cost of Service*, July 16, 2015, p. 41

in the absence of more detailed information as to the specific in-service dates of projects. This is commonly referred to as the "half-year" rule. For non-rebasing years subsequent to a test year, assets that went into service in the preceding test year would continue to attract only a half year of return of and return on capital, until the next rebasing application.

The half-year rule is an approximation of when, during a test year, assets enter service. In the absence of more detailed forecasts, the half-year rule assumes that all new assets enter service on July 1 (half way through the test year) for ratemaking purposes. In some cases, more refined in-service date forecasts are available which result in "partial-year" treatment, as appropriate, as opposed to exactly "half-year" treatment.

KPMG identified alternative methods that have been used in other jurisdictions that provide more refined calculations based on when assets enter service. These include the following:[3]

- Average of quarter-end balances. The average net book value is the average of the four quarterly balances, and depreciation expense is comparably calculated. This provides a slightly more accurate representation than the half-year of the average net book value, but with additional accounting and slightly more complex calculations for rate-setting.

- 12-month average of month-end balances. This is a more refined and accurate representation of when assets actually enter service, but which requires additional accounting and more complex calculations for rate-setting. Ontario natural gas distributors and some electricity distributors employ this approach as they generally forecast monthly in service dates for their new assets.

- 13-month average of month-end balances. Some U.S. jurisdictions use 13-months, calculated as the values for December 31 of the prior year, plus the twelve month-end values in the test year. This provides an average from the opening test year to closing test year balances but provides a more accurate average NBV of assets during the year than does the half-year rule as it reflects more accurately when assets enter service. Like other approaches, it requires more accounting of data and more complexity in rate-setting calculations.

KPMG's review found that the half-year rule or a more detailed quarterly or monthly approach is used for rate-setting purposes in Canadian and U.S. jurisdictions

[3] KPMG's Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219* – Summary, pp. 3-6

surveyed.[4] Ofgem in the United Kingdom provides for no depreciation expense to be recovered in the year that assets enter service, but provides for full year recovery in subsequent years. No jurisdiction surveyed allows the full amount of depreciation and return in the test year for assets that enter service in that year.

3.2 Incentive Rate-setting Years

In the traditional environment of annual cost of service rate applications, the use of the half-year rule or a more detailed variation does not pose an issue for subsequent years following the inclusion of an asset into rate base for the first time. The rate base and the revenue requirement are updated every year; assets that receive half-year (or partial-year) treatment in the year that they enter service receive full-year treatment in subsequent years.

The nature of economic regulation, particularly rate-setting, has evolved. Since the 1980s, performance-based regulation (PBR)/incentive regulation mechanisms (IRM) have evolved as an alternative to more traditional cost of service regulation. PBR/IRM can provide for any form of regulatory oversight that may be a better representation of the market forces that discipline the performance of firms in competitive markets.

With the OEB's performance based incentive rate-setting methodology, rates are no longer established on an annual cost of service approach. As a result, the half-year rule, or similar treatment, continues during the IR years. During the IR years, 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. On that theoretical basis, a utility can invest in future capital with no adverse impact on financial metrics. However, the theoretical approach does not consider inflation or growth in electricity demand and growth in number of customers.

KPMG undertook various analyses to assess the impact of the half-year rule under the OEB rate setting approach of a cost of service review followed by four years of IR adjustments. KPMG compared the OEB approach against annual cost of service applications, where the utility was held whole through the annual update of the rate base and revenue requirement, and also against the scenario of cost of service and IR with full-year depreciation.

[4] However, in most cases, it appears to the OEB that the approach adopted has been so long institutionalized that the justification for the approach is long forgotten. Nor does there appear to be questions of the appropriateness of the approach persisting during non-rebasing periods and whether it raises concerns of sufficiency or deficiency of recoveries.

While the analyses were hypothetical, KPMG used data that would be representative of a "typical" utility. Various assumptions of growth, capital additions-to-depreciation, and other parameters were modelled. The analyses demonstrate how sensitive the results can be to assumptions about the parameters. Nonetheless, the OEB considers that the analyses were informative.

KPMG concluded that the half-year rule creates a notional deficiency assuming no customer growth when capital expenditures are greater than or equal to the amount of capital expenditures notionally reflected in base rates. However, KPMG also noted that, with revenue growth above 1.1%, a revenue sufficiency could result.[5] KPMG notes that results can vary as they are sensitive to the operational circumstances and parameters of individual distributors.

The jurisdictional review by KPMG does not reveal any general concerns with the use of the half-year rule or a similar mechanism persisting into non-rebasing years. KMPG recommended that "IR rates not be normalized for the effect of the half year rule in the rebasing year on a pro forma basis for all distributors due to the potential for normalized IR rates to be greater than those associated with an annual cost of service rates scenario". KPMG noted that whether any revenue deficiency was material was dependent on the circumstances of each utility.[6] While there was no consensus in the working group on whether IR rates should be normalized for the effect of the half year rule, there was general agreement that the level of any deficiency would be dependent on the circumstances of each utility.

The OEB recognizes that, due to inflation, the replacement value of many assets will be higher than the original price of that asset. However, there are many other factors to consider, such as contributed capital policies, customer growth, changes in technology and the age demographic of assets (and when they become fully depreciated) that can vary from distributor to distributor. Setting rates through the IR mechanism inherently disconnects the rates from the underlying costs of the utility in order to incent efficiency improvements. The very nature of the mechanism recognizes that there can be many different factors that can influence both positively and negatively on a utility's return. The half-year rule is just one of these factors.

The OEB will not alter its policy of allowing the half-year rule (or analogous approaches) to persist through the Price Cap IR period. It is not appropriate to adjust for one factor, such as any shortfall due to the use of the half year rule, without considering all other factors that arise through an IR period. The OEB has already included several options

[5] KPMG's Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219*, p. 12
[6] *Ibid*., p. 44

that distributors can leverage to address their unique circumstances. In 2012, the OEB established rate-setting options for distributors, including the Custom IR method. With Custom IR, a five-year forecast of a distributor's costs is considered. Distributors opting for the Price Cap IR option have access to a capital module (either the ACM or ICM) to fund material capital costs.[7] As part of this Supplemental Report, the OEB is reducing the dead band in the materiality threshold calculation for both the ACM and ICM, making these mechanisms more accessible to distributors. In addition, distributors experiencing extraordinary events can file an application for a Z-factor to recover costs of material events that are beyond their control.

[7] The ICM option has been available since its introduction in late 2008 for 3rd Generation IR, and continued under the RRFE options. The ACM Report, issued in September 2014, introduced the ACM concept as an evolution of the ICM and modifying some of the policies applicable to both ACM and ICM requests.

4 The ACM/ICM Materiality Threshold Formula

In the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673), (the 3rd Gen IR Supplemental Report) the OEB introduced the Incremental Capital Module. The ICM included a materiality threshold to determine qualifying capital projects and the associated incremental capital amounts that would be recoverable during the IR period, until the distributor's next cost of service application. The ICM materiality threshold is discussed in section 2.3 of the 3rd Gen IR Supplemental Report.

The OEB established the following formula to be used by a distributor to calculate the materiality threshold that will apply to it:[8]

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right] + 20\%$$

This formula has been used since that time.

In September of 2014, the OEB issued the ACM Report. The ACM Report retained the same materiality formula while providing further guidance and clarity on its application on ICM and the new ACM options for funding eligible incremental capital. At that time, the OEB noted that it intended to further review certain components of the formula in light of the experiences with ICM applications to date and in consideration of the evolution of the ACM/ICM concept in support of the OEB's RRFE rate-setting approach.

KPMG examined the growth factor g and the dead band, currently at 20%. OEB staff also considered how to adapt the formula, which was single-year in nature, to be applicable to the multi-year Price Cap IR term currently in place. A further consideration was whether the use of the actual distributor-specific stretch factor is reasonable given the purpose of the formula is to derive an incremental amount of capital that may be eligible for funding during the IR term.

The following concepts of the materiality threshold formula are discussed below.

- The Multi-Year Formula
- The Growth Factor
- The Dead Band
- The Stretch Factor

[8] Definitions of the terms are provided in Appendix B.

4.1 The Multi-Year Formula

The original materiality threshold formula for an ICM was structured to support a single year-over-year change (i.e., from the cost of service rebasing to the first IRM rate adjustment application in the following year). However, a distributor could apply for an ICM as part of its annual IRM rate adjustment for any year subsequent to its cost of service application. The single year-over-year formula does not take into account the passage of time over the subsequent IRM period (i.e., the cumulative impacts of cost, inflation, productivity and changes in customers and demand). In addition to the lack of multi-year impacts, as originally conceived and applied, the formula would give the same value regardless of which IR year past rebasing the application was addressing.[9]

Under 3rd Generation IR, there were originally three annual price rate adjustments between rebasing applications. Now there are routinely four under the Price Cap IR regime instituted as part of the RRFE. Further, in conjunction with the OEB's recent policy relating to deferring rebasing pursuant to executed mergers, acquisitions, amalgamations and divestitures, the period between rebasing applications could be considerably longer.[10]

Having reviewed more than a dozen ICM applications since adopting the ICM, the OEB is of the view that the materiality threshold should change over time during the IR term. The amount of capital that is funded each year should change relative to what was funded in rebased rates to reflect the current price cap adjustment and growth in demand.

This concept may not have been as important when the ICM was first introduced because at that time the normal cycle was four years (cost of service to rebase rates followed by three years of IR adjustments). With the adoption of a five year cycle (rebasing followed by four years of Price Cap IR) and the introduction of the ACM review for projects in conjunction with the 5-year DSP, the cumulative temporal impact is more significant.

In the recent working group, OEB staff proposed a variation on the formula to address this matter, noting that it would be the multiplicative and cumulative impact of both the price cap adjustment and growth that increases the amount effectively funded through

[9] This is true for an ACM application where the variables in the formula are not affected by which year of the IR period the ACM is being requested. However, for an ICM, the PCI will change from year to year during the IR period and this will change slightly the corresponding threshold amount.
[10] *Report of the Board: Rate-Making Associated with Distributor Consolidation (EB-2014-0138)* March 26, 2015, section C

rates in each subsequent price cap year. OEB staff prepared a modified formula to be used for ACM and ICM applications. No concerns were raised by the working group.

The OEB adopts the multi-year formula to be used for ACM and ICM applications. This applies both with respect to ACM proposals reviewed in cost of service applications, and to ACM/ICM applications for rate riders to fund qualifying ACM/ICM capital projects coming into service during the Price Cap IR term.

4.2 The Growth Factor

In the OEB's view, a reasonable growth estimate should also be accounted for in the materiality threshold calculation. Capital additions are often, at least in part, to connect and serve new customers. However, new customers and demand also mean new revenues that help to recover the costs to serve the new demand. This is in addition to increased revenue due to the $I - X$ (i.e., price cap index or PCI) price cap adjustment to base rates each year.

As originally formulated and implemented in the 3rd Gen IR Supplemental Report, growth is represented by the change in (economic) demand[11] between two time periods. Economic demand is composed of three elements for electricity distribution:

- Number of customers
- kilowatt hours (kWh) of electricity consumption
- kilowatts (kW) of energy demand, for demand-billed customers

Growth is estimated as the weighted average of the change in each of these demand components between two time periods, where the weights correspond to the revenue weights. For this calculation, prices are held fixed between the two periods, as the impact of changes in prices due to price cap adjustments is captured by the PCI variable in the formula.

4.2.1 Weather Normalized vs. Weather Actual Data

The original growth calculation established by the OEB compares the weather-normalized load forecast from the most recent cost of service application to recent weather-actual demand. Variability in weather (and in other factors, notably economic activity) can influence the period-over-period change in demand. Comparing weather-normal against weather actual demand introduces variability into the results.

[11] The use of the term "economic demand" is used to distinguish it from "electricity demand" (i.e. peak demand in *kW).*

However, KPMG determined that this is largely unavoidable given the methodology. It also noted that there is no tangible quantitative evidence that the present calculation is resulting in a systematic bias in the materiality threshold formula, resulting in a misspecification of the amount of capital that is reflected in rates.[12]

The OEB observes that any error introduced is reduced by the proportion of revenues that are from non-weather-sensitive charges – the monthly fixed service charge, variable charges for non-weather-sensitive customer classes, and due to the fact that there is base load consumption even for weather-sensitive customers. The rate design initiative implemented following the completion of the KPMG Report, for the Residential customer class, will also reduce the distribution revenues subject to weather variability, so that any weather-sensitive errors will be further minimized.

Accordingly, the OEB will not revise this component of the approach to the calculation of the growth factor.

4.2.2 Annualized Growth Factor

Consideration of the previous issue, and of potential options, revealed another matter related to the operationalization of the ACM/ICM policy. As originally derived (and discussed above), the materiality threshold is a single year-over-year change.

The ICM spreadsheet, and now the new ACM module, compare the most recent actuals (excluding the cost of service year) against the cost of service test year forecast. A review by OEB staff revealed that with the previous formula, a two-year growth is calculated for ICM applications that are filed in year three of the IR period. This is because it is dependent on the year of the most recent actuals relative to the test year, as documented in Appendix C of this Supplemental Report. The analysis indicated that this was unlikely to have been an issue when the ICM was introduced in 3rd Generation IR, when there were normally only three years of price cap adjustment applications between cost of service applications to rebase rates. A review of ICM applications to date has indicated that no ICM applications with two-year growth rates have been considered.

With the extended term for Price Cap IR, whereby there are now normally four years between rebasing applications, there is an increased possibility that a two-year growth factor will occur for an ACM/ICM application. Also, where an ACM is filed as part of a cost of service application there is, almost without exception, a two-year difference between the most recent historical actuals and the test year forecast.

[12] KPMG's Report, *New Policy Options for the Funding of Capital Investments: EB-2014-0219*, p. 35

With the adoption of a multi-year formula, it is appropriate that the growth factor g, like the approach to the current PCI, be annualized. Where the module calculates a two-year growth rate (i.e. for the ACM in a cost of service application or in the fourth Price Cap IR application), a proxy for the annual growth rate is realized by dividing the growth rate calculation by two.[13,14] The proposed revision to the growth factor was discussed and no concerns were raised by the working group.

The ACM materiality threshold formula will be modified to incorporate an annualized growth factor.

4.3 The Dead Band

As enunciated by the OEB in the 3rd Gen IR Supplemental Report:

> Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.[15]

In the end, the choice of the level of the dead band is not founded on any theoretical basis, but is a practical decision to balance identification of legitimate proposals for necessary incremental capital funding versus numerous marginal applications.

The KPMG analysis, and in particular its modelling of various scenarios, examined the influence of the dead band and the impacts of the adoption of TFP and IFRS on the dead band variable. In its report, KPMG concluded that the adoption of TFP as the basis for the productivity factor for Price Cap IR and the adoption of IFRS have no

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[13] While a more exact calculation is possible, this proxy is simpler. Further, as growth in demand is typically less than 2%, any error is likely immaterial.
[14] Under the recent report on rate setting under distributor consolidation (see footnote 5), three-year, four-year or longer period growth rates in the ACM spreadsheet could result under extended deferral periods. Dividing by 3, 4, etc., as appropriate, would give a suitable annualized growth rate. These will be exceptions dealt with on a case-by-case basis.
[15] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors EB-2007-0673*, September 17, 2008, p. 33

material or sustained impacts on the materiality threshold formula as it was first derived in 2008.[16]

However, KPMG recommended that the dead band could be reduced, even to zero, in order to balance what it viewed as competing objectives such as encouraging effective distributor planning, including the development of appropriate asset management plans, while reflecting the static nature of the materiality threshold formula and protecting rate payers from paying for incremental capital expenditures that are already notionally reflected in base rates. KPMG noted that the determination of the dead band is ultimately a discretionary matter for the OEB, using its expert judgment to balance competing objectives. KPMG also provided an analytical example that if the dead band is maintained at the 20% level, the materiality threshold formula would generate a dollar value of capital in rates which is larger than the notional capital reflected in rates throughout the IR period.

For the reasons set out in the 3rd Gen IR Supplemental Report, the OEB is of the view that the dead band should remain above zero. The dead band being set at zero means that any qualifying incremental capital above what is factored into rates, and adjusted by the Price Cap Index and growth, would be fundable through an ACM/ICM rate rider. However, the OEB recognizes the imprecision in the Price Cap IR formula, and in the estimates and data used in the formula and in rate-setting generally.

Further, a utility's management is expected to control or influence what it needs to do from both a capital project perspective and ongoing operations to distribute electricity to customers in a safe, reliable and high quality manner. Regulatory approaches such as IR, and augmented by the OEB's RRFE approach, provide flexibility for the utility's management to do so.

With this in mind, the OEB considers that a dead band remains an appropriate means to allow for appropriate funding for qualifying ACM/ICM projects, while discouraging numerous applications for marginal amounts that the utility would be expected to manage under the RRFE and Price Cap IR framework. However, maintaining the dead band at 20% may not be responsive to the OEB's RRFE objectives of enhanced distributor planning and effective access to available regulatory tools to facilitate pacing and prioritizing needed capital investments.

Furthermore, with the adoption of the multi-year formula discussed in 4.1 above, the OEB concurs that the dead band should decrease. The materiality threshold has been

[16] KPMG's Report, New Policy Options for the Funding of Capital Investments: EB-2014-0219, p. 38 and pp. 40-41

used in its original formulation regardless of which year in the IR term the ICM application was proposed. The multi-year formula now explicitly and appropriately factors in the cumulative, multiplicative impact of both growth and the price cap index over the years since the utility's last cost of service rebasing application. In part, this may have been captured implicitly (and imperfectly) through the earlier dead band.

The OEB has determined that a dead band of 10% is more appropriate in light of the changes being made to the materiality threshold formula, and balancing the need for appropriately funding necessary incremental capital investments while avoiding numerous marginal applications and providing some protection that amounts are not already funded through rates.

In the OEB's view the redefined materiality threshold formula and the redefined growth and dead band variables should provide better information on when incremental capital projects qualify and on the quanta of qualifying capital investment dollars that should be funded in advance of the next cost of service application.

4.4 The Stretch Factor

Currently, as an input to the materiality threshold formula, a utility uses the most recent stretch factor applicable to it, as derived from the annual benchmarking analysis commissioned by the OEB. The stretch factors are primarily used for calculating the price cap adjustment for IR applications. Under the current IR framework, the stretch factors range from 0% to 0.6%, with more efficient utilities, as determined through the econometric analysis, assigned a lower stretch factor. However, most utilities will be grouped into the middle cohort and have a 0.3% stretch factor. The stretch factors are updated annually, and can change over time, although movements are typically gradual.

As part of the working group's discussions, OEB staff noted that, with the multi-year formula, the stretch factor could change from year to year. In addition, the stretch factor has an impact on the materiality threshold calculation, as it is included in the PCI variable. OEB staff observed that the impact of the stretch factor on the materiality threshold is counter to the incentive that underpins the price cap adjustment: a more efficient utility would have a lower stretch factor and a higher PCI and, consequently, a higher materiality threshold result than would a less efficient utility. This means that a more efficient utility would have less available capital for incremental funding than would a less efficient utility, all else being equal.

OEB staff recommended that the middle stretch factor of 0.3% be used as a default, instead of updating with the distributor's most recently published stretch factor. This would eliminate any counter-intuitive impacts as mentioned above and put utilities on an equal footing regardless of their efficiency ranking with respect to access to qualifying incremental capital. Use of the 0.3% would also simplify calculations.

There was no consensus on this proposal, as one view suggested that this was a change in the methodology that needed to be considered from the start, or as part of a review of the entire materiality threshold formula. The change would disadvantage utilities with less efficient rankings.

The OEB considers that the proposal to use the 0.3% stretch factor as the default is reasonable in that it neutralizes the threshold test in terms of being impacted by performance. An analysis conducted by the OEB staff using filed ICM models from previous applications indicates that the impact of using a 0.3% stretch factor instead of 0.6% is approximately 4% on the resulting capital expenditure threshold, even with the adoption of the multi-year formula. While the difference in available capital is not insignificant, on an annual revenue requirement basis it is likely below a distributor's materiality threshold as outlined in the OEB's Filing Requirements[17] . Since a 0.3% stretch factor would apply to most utilities, and in most years, any bias would be minimal.

The OEB has determined that the stretch-factor assigned to the middle cohort (currently 0.3%) be used in the materiality threshold calculation for any ACM/ICM application.

4.5 The New ACM/ICM Materiality Threshold Formula

As a result of the work of KPMG and OEB staff, and considering the feedback from the working group members, the OEB will alter the materiality threshold formula by adding the highlighted portion as follows:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where n is the number of years since the cost of service rebasing. Other parameters are as defined in the original formula, except for the following changes:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

[17] *Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, Chapter 2*, pp. 13-14

Appendix B provides further details on the updated formula and parameters.

The right-hand side of the equation has been altered to reflect the cumulative and multiplicative impact of both growth and the price cap adjustment over time during the Price Cap IR term.

5 Filing Requirements

Section 5 of the ACM Report provided information on the filing requirements related to ACM and ICM applications as part of cost of service or Price Cap IR applications. The nature of the information required for an ACM or ICM application is unchanged by the policies adopted by the OEB in this Supplemental Report.

The OEB-issued model for the ACM/ICM has been updated to reflect the changes in the materiality threshold formula and associated parameters adopted in this Supplemental Report. The updated ACM/ICM model is posted on the OEB's website, and applicants should use that version in cost of service or Price Cap IR applications, as necessary.

The changes to the materiality threshold formula adopted herein and the determinations made by the OEB on the half-year rule will be reflected in the Filing Requirements applicable to cost of service and Price Cap IR applications for electricity distributors when the Filing Requirements are next updated.

Appendix A

The Capital Module Policy [Unchanged from the ACM Report]

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Appendix B

Materiality Threshold Calculations [Updated]

The following table explains the variables used to determine the preliminary materiality threshold for ACM/ICM proposals in both cost of service applications and as part of Price Cap IR applications for rate riders to recover qualifying ACM/ICM incremental capital investments.

General Formula:		$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + 10\%$	
Parameters		**Preliminary Calculation for proposed ACM-qualifying capital projects, as part of a Cost of Service Application**	**Final Calculation for pre-qualified ACM projects or for proposed ICM projects, as part of a Price Cap IR Application**
Rate Base	RB	In its application, the utility should use its proposed test year rate base.	The distributor should use the approved rate base from its last cost of service application.
Depreciation	d	In its application, the utility should use its proposed depreciation expense for the test year.	The distributor should use the approved depreciation expense from its last cost of service application.
Growth	g	g is always to be expressed as an annual growth rate. Growth is calculated based on the percentage difference in distribution revenues between the forecast distribution revenues for the test year and the distribution revenues from the most recent complete year. There is normally a two-year gap between the most recent actuals and the test year forecast in the cost of service application, so the growth factor is annualized by dividing by two.	g is always to be expressed as an annual growth rate. Growth is calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application. In the first and second Price Cap IR years following rebasing, a distributor will not have a complete year of data following the cost of service base year. For these years, the growth factor reflects the difference between the OEB-approved distribution revenues from the last cost of service application and the most recent complete year prior to the rebasing year. By the fourth year of Price Cap IR following rebasing, there will be a two year gap between the most recent actuals and the approved cost of service test year forecast; the growth factor is annualized in this situation by dividing by two.[18]
Price Cap Index (IPI – stretch_factor)	PCI	Distributors should use the IPI from its most recent Price Cap IR application and the stretch factor assigned to the middle cohort.	Distributors should use the IPI from its most recent Price Cap IR application as a placeholder for the initial application filing. This information is updated if new information becomes available during the proceeding. Distributors must use the stretch factor assigned to the middle cohort as the default stretch factor.
Years Since Rebasing	n	n is the number of years after rebasing	n is the number of years since the last rebasing.

[18] *See Appendix C for a more detailed breakdown*

Appendix C
Growth Factor Calculation for Final ACM/ICM Materiality Threshold

2016 Test Year Example

Price Cap IR Year (past rebasing in 2016)	Year	Growth Factor Revenues		Is Growth one-year or multi-year?
		Numerator	Denominator	
1	2017	OEB-approved 2016 test year	2015 historical actuals	One-year
2	2018	OEB-approved 2016 test year	2015 historical actuals	One-year
3	2019	2017 historical actuals	OEB-approved 2016 test year	One-year
4	2020	2018 historical actuals	OEB-approved 2016 test year	Two years (will be annualized)
5[19]	2021	2019 historical actuals	OEB-approved 2016 test year	Three years (will be annualized)
etc.				

[19] *If longer than four years on Price Cap IR (e.g. due to a merger or amalgamation, or approved deferred rebasing)*

Table 1: Rate-Setting Overview - Elements of Three Methods

		4th Generation IR	Custom IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Productivity factor		
		Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

2.2.1 Productivity Factor

In its RRF Report, the Board determined that the productivity factor will be based on Ontario electricity distribution industry TFP ("industry TFP") trends and should be derived from objective, data-based analysis that is transparent and replicable. Furthermore, the **Board determined that the productivity factor determination under the new Price Cap IR will continue to rely on the index-based approach**. The Board also stated its intention to update the productivity factor every five years (e.g., the update after 2014 would be in 2019).

The indexing method to estimating Industry TFP continues to be the most common basis for setting a productivity factor in rate setting formulas. In addition, the Board concludes that the approach is simpler than the alternative "econometric" approach proposed by Prof. Yatchew and therefore may be better understood by stakeholders and consumers.

The Board invited written comment on its intention to update TFP next in 2019.[14] Some stakeholders expressed concern over how this may impact distributors, particularly if it is applied to all distributors regardless of where they are in their IR term. The Board's approach is intended to provide greater certainty as to the time to achieve or surpass the external benchmark and retain any achieved savings. For distributors to benefit from that certainty, the industry benchmark needs to be in place for a reasonable period of time. The period of time generally used coincides with the IR plan term, and is a common feature of many IR plans. The Board is concerned that allowing for a change in the productivity factor midway through an IR term will erode the incentive benefits of providing stability and predictability in the achievable industry external benchmark. As such**, the Board has determined that the productivity factor will remain in effect until a distributor's next rebasing**. The stretch factor however will change annually,

[14] Ontario Energy Board. Letter to Stakeholders re: Update on Timeline for Expert Reports and Written Comments. May 30, 2013.

TAB 5

3.2.3 Capital Factor (Issue 9)

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

Hydro One has proposed a capital factor to provide incremental funding for new capital investments during the term. The capital factor was modelled based on a similar factor approved for Toronto Hydro in its 2015 Custom IR rate proceeding.[57] The capital factor calculates a percentage change in the revenue requirement attributable to new capital investment that is not being funded through the inflation less expected productivity (I - X) adjustment. The calculation includes depreciation, return on equity, return on debt and taxes attributable to new capital investment placed in-service for 2019 to 2022 of the Custom IR term.

For Hydro One's proposed capital factor the revenue requirement would increase by the following percentages each year to provide funding for incremental capital,[58] in addition to the inflation less expected productivity (I – X) adjustment:

Table 3
Hydro One Proposed Capital Factor

	2019	2020	2021	2022
Capital Factor	2.32%	2.21%	3.14%	1.69%

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

PWU supported Hydro One's proposed capital factor.[59]

AMPCO did not oppose the proposed capital factor, but submitted that if there is an application update for 2021, the capital factor should be reviewed and updated. The update would be based on the variance between actual versus forecasted capital spending during the first three years of the plan (i.e., 2018-2020).[60] Similarly, CCC

[57] EB-2014-0116.
[58] Letter filed by Hydro One on the Hydro One Accountability Act, October 26, 2018, page 6.
[59] PWU, *op. cit*., p. 10.
[60] AMPCO, *op. cit*., pp. 5-6.

submitted that the OEB should approve a capital factor for the 2018-2020 period, with Hydro One reporting on the achieved results to set the capital factor for 2021 and 2022.[61]

VECC was opposed to the capital factor, submitting that it is “not consistent with the principles of incentive rate making and does not follow the intent of the RRFE framework.”[62] BOMA also expressed concerns regarding the capital factor, submitting that it lessened the incentive to impose discipline on capital spending, and was more permissive than the OEB’s IRM and incremental capital module (ICM) framework.[63]

CME submitted that the working capital portion should be removed from the rate base calculation used for determining the capital factor. CME argued that the return on debt, return on equity and income taxes associated with the working capital allowance component of rate base have nothing to do with the capital expenditures and additions that result from the DSP.[64]

Hydro One submitted that its large capital requirements on an on-going basis preclude it from the OEB’s traditional Price Cap IR mechanism, referring to the Rate Handbook, the RRFE Report and related OEB documents on capital funding mechanisms.[65]

Hydro One disagreed with CME that working capital should not be included in the calculation of the capital factor because the inclusion of working capital:

- is consistent with prior decisions[66]
- represents a prudently incurred cost
- allows for the integration of the additional working capital requirements of the Acquired Utilities

Findings

The OEB approves the approach to the capital factor as proposed by Hydro One, but imposes an additional 0.15% stretch factor to be subtracted from the calculated capital factor. This is in addition to the 0.45% stretch factor applied to the revenue requirement

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[61] CCC, *op. cit*., pp. 8-9.
[62] VECC, *op. cit*., p. 8.
[63] BOMA, *op. cit*., pp. 6-8.
[64] CME, *op. cit*., pp. 8-9.
[65] Hydro One, Reply Argument, *op. cit*., pp. 30-32.
[66] Toronto Hydro-Electric System Limited, Decision and Order EB-2014-0116, December 29, 2015.

and the reductions to the capital program discussed under Issue 30. Hydro One is directed to recalculate the capital factor to reflect the OEB's findings on its capital program and to include the incremental stretch factor.

Hydro One has argued that the 0.45% stretch factor inherent in the (I – X) adjustment is applied to the revenue requirement, and therefore applies to both OM&A and capital. The difference between the treatment of OM&A and capital with Hydro One's proposal is that funding for OM&A is not based on a forecast of OM&A costs. For OM&A, Hydro One is expected to manage within an increase of less than inflation (I – X) each year, regardless of its forecast costs. This is to incent the company to find productivity improvements. For capital, however, Hydro One has forecast capital expenditures for each year of the term, and is seeking funding for any incremental capital not funded by the (I – X) adjustment. The rate base from these forecast capital expenditures is increasing by more than inflation.

Hydro One has said that it has developed productivity initiatives and embedded these in its business plan for both OM&A and capital, with respective managers accountable for delivering the expected savings.[67] Hydro One provided a governance document[68] that explains the process for tracking and reporting on these productivity initiatives. For capital, the initiatives included Move to Mobile, Procurement and Telematics for a total of $184.7 million of expected savings from 2018 to 2022, which is only 5.2% of the total proposed capital expenditures of $3,571.3 million.[69]

The OEB agrees that this process of defining, executing and reporting on productivity initiatives is an enhancement to Hydro One's planning. The OEB expects Hydro One to stretch itself more to find additional initiatives and to consider new approaches to its business. The OEB is therefore imposing an additional stretch factor for the capital factor of 0.15% to incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront.

In imposing this stretch factor, the OEB also recognizes the argument made by intervenors that for the last rate framework term, Hydro One overspent on in-service capital by $122.5 million, approximately 6.2% more than approved.[70] The OEB is approving the inclusion of this capital in the 2018 rate base because it is appropriate for a distributor to reprioritize work to meet changing circumstances. However, in

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[67] Exhibit B1-1-1, DSP Section 1.5, page 2 and Exhibit B1-1-1 DSP Section 1.1, page 10.
[68] Exhibit B1-1-1 Section 1.4 Attachment.
[69] Letter from Hydro One, re: Hydro One Accountability Act, October 26, 2018, page 5.
[70] Tr. Volume 6 page 134.

reprioritizing work, Hydro One should make every effort to stay within its approved spending envelope.

The OEB finds that the calculation of the capital factor will not include a component for working capital in rate base. The capital factor provides funding for capital expenditures not funded through the (I – X) adjustment, and the OEB has determined that providing additional funding for working capital is inappropriate in this context. The OEB notes that the Rate Handbook expressly identifies the working capital allowance as an element the OEB expects will not be explicitly updated as part of annual update applications.[71] Furthermore, the working capital allowance is already implicitly increased annually through the (I – X) adjustment.

PEG expressed concerns that with the capital factor the "Company is perversely incented to spend excessive amounts on capital to contain OM&A expenses".[72] PEG recommended that a "materiality threshold and dead zone" be added to the capital factor. The OEB has adopted a materiality threshold and 10% dead zone for the incremental capital module (ICM) available to distributors on the Price Cap IR option. An ICM is a different mechanism than the proposed capital factor, and there is no detailed evidence on how a materiality threshold and dead zone would be incorporated into a capital factor. The OEB will therefore not adopt this specific approach. However, the OEB has taken this recommendation into consideration in the adoption of the incremental stretch factor that will apply to the capital factor.

3.2.4 Program-Based Cost, Productivity and Benchmarking Studies (Issues 10, 11 and 12)

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

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

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

[71] Rate Handbook, *op. cit*., page 26.

[72] Exhibit M1, page 6.

TAB 6

These results provide strong evidence that PSE's total cost benchmarking results for Toronto Hydro are not robust.

Alternative Reliability Models

PEG developed alternative econometric reliability models using the data provided by PSE in its working papers. We modelled CAIDI and SAIFI using business condition variables obtained from PSE and an additional weather variable that are pertinent to power distributor reliability performance. The sampled companies were the same. We extended the sample period to include 2017.

Results of our reliability research can be found in Tables 1 and 2. Our SAIFI model indicates that SAIFI was higher the greater is the share of distribution assets overhead. The SAIFI impact of overheading was magnified by forestation. Our research also shows that SAIFI was greater

- the lower is the share of the service territory that was urban
- the greater were extreme temperatures in the service territory.
- the more extensive was forestation when more distribution plant is overhead
- the greater was precipitation
- the greater was the standard deviation of elevation
- when the IEEE major event day standard was used.

The parameter estimate for the trend variable suggests that the SAIFI of sampled utilities trended downward by 1.85% annually for reasons not explained by the model's business condition variables. The adjusted R-squared of the model was 0.30%. While this is much lower than in our cost models, it should be remembered that the SAIFI metric already controls for the number of customers served.

Our model for CAIDI indicates that CAIDI was higher

- the greater was the share of service territory area that was urban.
- the more extensive was forestation
- the greater was the area of the service territory per customer
- the greater was precipitation
- the greater was the standard deviation of elevation in the service territory.