HYDRO OTTAWA INTERROGATORIES

M-HOL-1

Reference: Exhibit M

Preamble:

In several instances in the report entitled *Custom Incentive Rate Mechanism Design for Hydro Ottawa* ("the Report"), Pacific Economics Group Research LLC ("PEG") makes statements regarding the prospect of a utility seeking to avail itself of the Custom IR method for successive rate plans.

For example, page 10 of the Report states the following:

> *It seems desirable to consider how to make Custom IR more streamlined, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors. Utilities should be encouraged to not stay on Custom IR indefinitely.[9] Regulators in other jurisdictions (e.g., Alberta and Britain) who championed IR but found themselves saddled with a system that retained too many cost of service features have reconsidered and reformed IR at the end of each round of plans.*
>
> [9] See EB-2018-0165, Decision and Order, December 19, 2019. While approving Toronto Hydro's Custom IR plan for 2020-2024, the OEB stated:
>
> *Toronto Hydro indicated that intervenors are asking the OEB panel to either make changes to generic policy through a particular utility's rate application or to fetter the discretion of a future panel. Toronto Hydro also submitted that its proposed ratemaking formula is structurally the same as the one approved in its 2015-2019 Custom IR proceeding. The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework.* (p. 24)

Similarly, on page 71 of the Report, PEG declares that "[t]he OEB has evinced mounting frustration with the cumbersome Custom IR option that most large Ontario utilities now request...Custom IR should be streamlined and/or used less frequently."

During its discussion on the C Factor and S Factor treatments for capital, PEG offers the following comment on page 74: "A higher markdown could, over time, materially reduce the number of capex plans eligible for Custom IR. It could particularly discourage continuation of Custom IR when utilities are approaching the end of a period of high capex."

And page 83 includes a final remark on this topic: "Accumulating experience with Custom IR in Ontario (and analogous mechanisms elsewhere) suggests that it would be desirable to limit its usage. In addition to making its terms less favorable to utilities, the OEB should consider limiting the frequency with which utilities can use Custom IR."

Questions:

a. Please identify any provisions or statements in the OEB's 2012 report *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* the OEB's 2016 *Handbook for Utility Rate Applications*, or any other relevant OEB reports or policies that corroborate and/or comport with the aforementioned assertions.

b. Please cite specific examples of the "mounting frustration" evinced by the OEB with respect to the review of Custom IR rate applications. Please identify the corresponding utility rate case proceedings.

c. Please explain how the excerpt from the OEB Decision and Order that is quoted in footnote 9 on page 10 of the Report can be interpreted as providing support for the assertion that "[u]tilities should be encouraged to not stay on Custom IR indefinitely." Please explain why footnote 9 should not be interpreted as the OEB signaling to Toronto Hydro that the utility's *current* Custom IR framework may not be acceptable to future OEB panels, and should instead be interpreted as the OEB signaling that *any* Custom IR plan put forward by Toronto Hydro may not be acceptable to future panels.

<u>Response to M-HOL-1:</u>

a. It is Dr. Lowry's view that the RRF report and the *Rate Handbook* emphasized flexibility in funding capex surges over concerns about regulatory cost, performance incentives, or overcompensation. Concerns about these other problems have evidently mounted as most of the larger Ontario utilities have requested Custom IR plans, some repeatedly. The OEB has not followed the path of regulators in Alberta, Australia, or Great Britain by launching a generic proceeding to reconsider the RRF as the first round of plans formulated under its guidelines expire. The OEB's frustration has been evinced chiefly in its decisions in recent proceedings which have considered specific proposals. Two Custom IR proposals have been rejected.[1] The OEB's dissatisfaction with Custom IR was particularly clear in its recent Toronto Hydro decision, which involved a second-generation plan.

It is also notable that the OEB's RRFE policy was not portrayed as a retreat from PBR. The decision includes the following statement.

> The Board's rate-setting policy in this Report represents a further development of the approach adopted by the Board when it first established performance based regulation ("PBR") for electricity distributors in its January 18, 2000 Decision with Reasons:
>
> > … PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board."
>
> Going into PBR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and

[1] The distributors with rejected Custom IR proposals were Hydro One Networks (EB-2013-0416/EB-2014-0247) and PowerStream (EB-2015-0003).

potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for ratebase to be re-calibrated annually.[2]

In its original RRFE report in 2012, the OEB stated "The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels."[3] It is by no means clear that the OEB expected such circumstances to continue for many utilities indefinitely.

b. Several specific examples of the OEB's mounting frustration with Custom IR were cited in Section 2 of Dr. Lowry's report.

c. Dr. Lowry was asked by OEB staff to explore for this proceeding alternatives to the ratemaking treatments of capital that have been approved to date in Custom IR plans. He concluded from his analysis that limitations on the use of Custom IR should be considered along with better approaches to Custom IR. In PEG's view, the OEB's cited remark about Custom IR could be interpreted as a suggestion for a utility to improve a future Custom IR plan relative to its current approved plan, but such improvements could include a substantially higher material materiality threshold that makes it unlikely that companies would operate continually under Custom IR. As another example, ten years of operation under a C factor approach could be coupled with a commitment to operate for at least five years under Price Cap IR or an Annual IR index.

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[2] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 10-11.
[3] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 19.

<u>M-HOL-2</u>
Reference: Exhibit M, p. 86
Preamble:
In its discussion on alternative ratemaking treatments of capital in Alberta and California, the Report states the following on page 86: "Some OEB Custom IR guidelines are violated since the capital revenue requirement is unaffected by the industry productivity trend or stretch factor."

Questions:

a. Please specify which OEB guidelines are purportedly being violated under the approach in question.

<u>Response to M-HOL-2:</u>

PEG believes that Hydro Ottawa's capital cost proposal violates several of the OEB's guidelines outlined on pages 25-26 of the *Handbook for Utility Rate Applications* and quoted on pages 11-12 of Exhibit 1, Tab 1, Schedule 10. In particular, Hydro Ottawa's proposed capital revenue requirement appears to be based entirely on a multiyear cost of service. This is inconsistent with the OEB's guidance that the forecast should "inform the derivation of the custom index, not solely to set rates on the basis of a multi-year cost of service". This design also seems to preclude an annual rate adjustment that is based on a custom index. Finally, Hydro Ottawa's proposed ratemaking treatment of capital cost excludes a stretch factor. This contravenes the OEB's guidance that "Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors."[4] According to Table 8 of the Exhibit 1/Tab 1/Schedule 8 of the Company's application, distribution OM&A expenses are expected to comprise about 42% of Hydro Ottawa's total cost. On a total cost basis, Hydro Ottawa is therefore effectively requesting approval of a stretch factor equal to about 0.15% X 0.42 = 0.063%. This is substantially lower than the stretch factor of all but the top performing power distributors in Ontario, which have stretch factors of 0%. This finding is not supported by the cost benchmarking evidence presented by Clearspring.

PEG also believes that the following discussion from the OEB's decision for Hydro One Networks in EB-2017-0049 is enlightening in considering Hydro Ottawa's proposed capital cost treatment:

[4] Rate Handbook, p. 26

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 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. Hydro One provided a governance document 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.

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**.[5] [Emphasis added]

[5] Ontario Energy Board, *Decision and Order EB-2017-0049 Hydro One Networks Inc.*, March 7, 2019, pp. 32-33.

M-HOL-3

Reference: Exhibit M, pp. 20-21

Preamble:

In footnote 36 on pages 20-21 of the Report, PEG quotes concerns expressed by OEB Staff regarding aspects of Hydro Ottawa's 2016-2020 Custom IR.

However, PEG makes no mention of the Decision and Rate Order ultimately issued by the OEB panel in the proceeding involving the utility's 2016-2020 Custom IR application. In that Decision and Rate Order, the OEB disagreed with the concerns expressed by OEB Staff and ruled thus: "The OEB finds that Hydro Ottawa's application and the settlement proposal prepared by the parties meet the expectations of the RRFE for a Custom IR. The OEB accepts the settlement proposal and approves the rates and charges that arise from it."[6]

Questions:

a. Please confirm whether PEG agrees with the aforementioned finding from the OEB that Hydro Ottawa's 2016-2020 Custom IR plan was consistent with RRFE expectations.

Response to M-HOL-3:

a. PEG acknowledges that the OEB made this statement on page 1 of the cited Decision and Rate Order. However, this order was issued before the OEB issued its Rate Handbook. On page 25 of the Rate Handbook, the Board stated "The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended." In PEG's view, Hydro Ottawa's proposal is inconsistent with Rate Handbook standards as well as with subsequent OEB decisions on specific Custom IR plans.

[6] Ontario Energy Board, *Decision and Rate Order*, EB-2015-0004, December 22, 2015.

M-HOL-4

Reference: Exhibit M, p. 8

Preamble:

PEG recommends that Hydro Ottawa's Custom Price Escalation Formula ("CPEF") be modified such that it includes a 0.27% base OM&A productivity trend. This figure is derived using U.S. distributor OM&A productivity trend data from 2007-2017.

Questions:

a. Please explain how the use of U.S. distributor data is informed and justified by the discussion of the pros and cons of Ontario and U.S. data, which is included in the Appendix to the Report.

Response to M-HOL-4:

a. The Appendix discussion was chiefly intended to explain why a statistical cost benchmarking study for Hydro Ottawa should rely chiefly on U.S data, as the Clearspring and PEG studies do. However, some of the pros and cons mentioned in this Appendix are also germane to the choice of data for an OM&A productivity trend study. Most notable in this regard is the transition of most Ontario power distributors to MIFRS accounting around 2012, which abruptly raised the OM&A expenses of many LDCs. Here are some other examples.

   - Data are not readily available for Ontario distributors on the share of labor costs in the applicable OM&A expenses. It is therefore not practical to deflate OM&A expenses with an OM&A input price index that has company-specific and time-varying cost shares.

   - Pension and benefit expenses are not itemized for easy removal if these expenses are slated for variance account treatment.

   - It is also pertinent that data are available in the United States for numerous electric utilities serving medium-sized metropolitan areas and experiencing brisk customer growth like Hydro Ottawa.

M-HOL-5

Reference: Exhibit M, p. 8

Preamble:

PEG recommends that the OEB not support the use of a fixed CPEF for purposes of Hydro Ottawa's Custom IR rate plan, particularly in light of the uncertainty surrounding the impacts of the COVID-19 pandemic.

Questions:

a. Please confirm whether it is PEG's view that a variable CPEF requiring annual updates from Hydro Ottawa is consistent with the OEB's policy, as stated in the *Handbook for Utility Rate Applications*, to minimize the number of annual updates required under a utility's Custom IR plan.

Response to M-HOL-5:

a. PEG acknowledges that, in its Rate Handbook, the OEB's standards for reviewing Custom IR applications include a limited use of updates during the plan term. On pages 26-27 of the Rate Handbook the OEB states the following:

> After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.
>
> The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.
>
> A Custom IR application can include a five-year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its

> needs within the five-year term or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances. The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.
>
> An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.
>
> Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

PEG believes that these provisions do not preclude updates for inflation and customer growth. Updates for inflation and customer growth would be mechanical, easy to review by the OEB, OEB staff, and other stakeholders, and involve little incremental cost if updates were already being filed regularly to operate deferral and variance accounts or for other reasons. The OEB has approved Custom IR plans for Toronto Hydro, and Hydro One Networks distribution and transmission since the issuance of the Rate Handbook which have allowed for an updating of the inflation measure in the indexing formula. Updates for inflation and customer growth reduce operating risk and forecast controversy without utility weakening performance incentives, and these benefits have been heightened by the economic uncertainty triggered by the coronavirus pandemic.

M-HOL-6

Reference: Exhibit M, p. 79

Preamble:

Page 79 of the Report states the following: “The capital variance account is the single leading cause of the weak capex containment incentives in Hydro Ottawa’s proposed plan.”

Questions

a. In light of this statement, please confirm whether PEG would still recommend application of the CPEF formula to capital revenue for rate adjustment purposes, if Hydro Ottawa were to correct the perceived deficiencies with the capital variance account.

Response to M-HOL-6:

a. PEG believes that a more incentivized capital variance account (or its suspension) would reduce concerns about weak capex containment incentives. However, the extent of incentivization would have to be much greater than in the Hydro One distribution and transmission plans to have much impact. Furthermore, concerns about overcompensation, high regulatory cost, windfall gains and losses, and Hydro Ottawa’s incentive to exaggerate its capex requirements and bunch capex would not be addressed by these means. Thus, an incentivized capital variance account should be a package that may also include a comprehensive CPEF.

<u>M-HOL-7</u>
Reference: Exhibit M, pp. 71-89
Preamble:
On pages 71-89 of the Report, PEG examines a range of alternative ratemaking treatments for capital.

Questions:

a. Please clarify whether it is PEG's view that these alternative ratemaking treatments for capital are compatible with existing OEB ratemaking policies, and as such, can be readily applied by the OEB in this and other proceedings.

b. Please clarify whether PEG believes that these alternative proposals do not require further analysis and/or stakeholdering by the OEB in a generic context (e.g. by way of a generic hearing or other suitable policy consultation) prior to their implementation.

<u>Response to M-HOL-7:</u>

a. PEG believes that many of the alternative ratemaking treatments of capital detailed in Section 6.2 of its June report are compatible with existing OEB ratemaking policies. These would obviously include alternative C factor and S factor treatments, and incentivized variance accounts since the Board has already approved such provisions. Custom IR is by nature customized. The plans already approved have varied considerably, and an approach approved for Hydro Ottawa need not be mandatory for subsequent applicants. Plans that result from settlements should merit serious consideration by the OEB even if they are innovative. This proceeding provides a great opportunity for Hydro Ottawa and other parties to explore innovations.

b. It is PEG's view that a generic hearing or other suitable policy consultation would be useful for considering some of the reforms discussed in Section 6.2 of PEG's June report and for gathering ideas from all Ontario utilities and from other stakeholders.

M-HOL-8

Reference: Exhibit M, p. 7

Preamble:

PEG states that one of its four larger concerns with Clearspring's research is that Clearspring included Ontario data from pre-MIFRS years in the sample. However, page 48 of the Report states that pre-MIFRS years were used in PEG's capital cost benchmarking model. Clearspring understands that PEG's rationale for not using pre-MIFRS years is that the accounting methodology for many Ontario distributors underwent modifications by 2013, and these modifications may have impacted classification between capital and OM&A.

Questions:

a. Please explain why PEG did not include the pre-MIFRS years for the Ontario data in the total cost and OM&A models, but did include those years in the capital model.

b. Does PEG believe that the accounting change impacted the reported capital data?

c. Will the capital costs for the Ontario observations after 2013 be constructed from data from two different accounting standards?

d. In light of Hydro Ottawa's response to interrogatory OEB-30, which showed that the shift to MIFRS had a minimal impact on Hydro Ottawa's cost data, what external evidence can PEG provide to explain why excluding a large portion of the Ontario distribution utility data is justified?

e. Please reproduce Table 6 and 7 found on pages 55 and 57 of the Report, respectively, by simply including the pre-MIFRS Ontario observations starting in 2006 to be consistent with the capital cost model.

f. Please reproduce Table 8 found on page 59 of the Report by excluding the pre-MIFRS Ontario observations to be consistent with the total cost and OM&A models.

g. Please reconcile the number of observations for the total cost model and the OM&A model. The OM&A model appears to have three more observations than the total cost model.

h. Please explain why PEG excluded Hydro One Networks data prior to 2013 from the sample, despite the company not shifting to MIFRS.

i. Please reproduce Table 6 and 7 by simply including the pre-2013 data for Hydro One Networks into the dataset.

Response to M-HOL-8:

a. PEG was principally concerned with the impact of MIFRS on reported OM&A expenses. Capital expenditures have also been affected, but the impact of MIFRS on annual capital cost has been less pronounced than on OM&A expenses. Total cost is chiefly driven by older capex. Assuming a 40-year service life, each dollar of overhead cost is spread over 40 years if capitalized. Therefore, the change in capital cost is only 2.5 cents versus one dollar if expensed. This makes it at least 40 times more important for OM&A than for capital. Since, additionally, a longer sample period has several advantages, we decided to use a longer sample period to estimate the capital cost model.

b. Please see the response to part a) of this interrogatory.

c. In this study, yes.

d. It was not clear how Hydro Ottawa's response to 1-OEB-30 demonstrated the asserted minimal impact. Hydro Ottawa's evidence in EB-2011-0054 had some tables showing the magnitude of the MIFRS and capitalization policy which are presented below. The impact was on the order of 10 million dollars or 16% of the Hydro Ottawa's OM&A expenses. Inclusion of earlier data would particularly complicate benchmarking of OM&A expenses and the calculation of an OM&A productivity trend. The transition to MIFRS had an even larger impact on the OM&A expenses of some of the other sampled Ontario utilities. Note also that neither PEG nor Clearspring use Hydro Ottawa's reported depreciation expenses in their cost calculations.

Table 1 – MIFRS Impact to Rate Base

Rate Base	CGAAP $000		MIFRS $000	
2011 Net Fixed Assets	$550,361		$549,935	
2012 Net Fixed Assets	592,707		592,002	
Average Net Fixed Assets		$571,534		$570,968
Cost of Power	680,576		680,576	
OM&A	65,698		75,988	
Working Capital Requirement @ 14.2%		105,971		107,432
Rate Base		$677,505		$678,400
Increase in Rate Base				$895

Table 2– MIFRS Impact to Revenue Requirement

Revenue Requirement	CGAAP $000	MIFRS $000	Difference $000
OM&A	$65,698	$75,988	$10,290
Depreciation	47,320	39,346	(7,974)
Return on Capital @ 6.95%	47,078	47,141	63
PILs	5,951	3,723	(2,228)
Service Revenue Requirement	166,047	166,198	151
Revenue Offsets	(9,026)	(9,026)	0

Hydro Ottawa performed an analysis of the cost allocations to determine which amounts will continue to be capitalized versus the amounts that are not considered directly attributable and therefore do not meet the criteria for capitalization under IFRS. The majority of the administrative burden was determined to be disallowable except for some costs pertaining to the supply chain function. The engineering and supervision allocations were also analyzed to determine which amounts could no longer be capitalized. Much of the disallowable portion related to training, health and safety costs, geographic information system and control room costs, future planning activities, and manager and supervisory costs that could not be linked to a specific asset. Table 5 summarizes that the increase in OM&A as a result of the above-mentioned disallowable costs is $10.5M.

Table 5 –CGAAP and MIFRS Capital Allocation for 2012 Test Year

Type of allocation	CGAAP 2012 Test Budget $M	MIFRS 2012 Test Budget $M	Difference $M
Labour and Fleet	$20.9	$20.9	$0
Administrative	7.0	1.2	5.8
Engineering	4.4	1.8	2.6
Supervision	4.0	1.9	2.1
TOTAL	$36.3	$25.8	$10.5

e. The following tables reproduce Table 6 and 7 found on pages 55 and 57 of the Report, respectively, by reestimating the original models including the pre-MIFRS Ontario observations starting in 2006 in order to match the sample for the capital cost model.

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2006	-18.1%
2007	-17.3%
2008	-14.6%
2009	-16.3%
2010	-16.7%
2011	-13.1%
2012	-13.9%
2013	-11.7%
2014	-7.8%
2015	-4.7%
2016	-4.4%
2017	-4.5%
2018	-1.3%
2019	*4.2%*
2020	*3.0%*
2021	*5.5%*
2022	*6.4%*
2023	*5.5%*
2024	*4.7%*
2025	*5.3%*
Annual Averages	
2006-2018	**-11.1%**
2016-2018	**-3.4%**
2021-2025	**5.5%**

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

Note: Italicized numbers are projections/proposals.

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2006	-41.4%
2007	-45.2%
2008	-31.5%
2009	-29.7%
2010	-27.0%
2011	-5.4%
2012	-17.5%
2013	-17.0%
2014	-10.1%
2015	-4.7%
2016	-6.0%
2017	-8.0%
2018	0.7%
2019	*1.2%*
2020	*-0.6%*
2021	*0.1%*
2022	*0.2%*
2023	*0.3%*
2024	*0.5%*
2025	*0.7%*
Annual Averages	
2006-2018	**-18.7%**
2016-2018	**-4.4%**
2021-2025	**0.4%**

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

Note: Italicized numbers are projections/proposals.

f. The following table reproduces Table 8 found on page 59 of the PEG's Report by *excluding* the pre-MIFRS Ontario observations to match the total cost and OM&A models.

Year by Year Capital Cost Benchmarking Results

Year	Percent Difference[1]
2013	-7.3%
2014	-4.6%
2015	-1.4%
2016	-0.7%
2017	0.7%
2018	2.4%
2019	*9.9%*
2020	*8.9%*
2021	*11.7%*
2022	*12.8%*
2023	*11.3%*
2024	*10.1%*
2025	*10.6%*
Annual Averages	
2013-2018	**-1.8%**
2016-2018	**0.8%**
2021-2025	**11.3%**

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

Note: Italicized numbers are projections/proposals.

g. The three-observation difference in the models was due to missing 2002-2004 gas customer data for Delmarva that were needed to calculate the percent electric customer variable. The YNG.dbf file we constructed to upgrade the gas customer data was missing these observations. When these data are added we get the econometric results for the total cost model and capital cost model. These results are provided in the response to HOL-14 part g). As one may expect, there is little change in results. The cost performance scores presented on Tables 6 and 8 of the June report are within 0.1% of the revised values. Because this issue does not materially change any of the results, we will note this for the record but not make changes to the report. Should additional changes be made to the model at a later date, these additional gas data will be included.

h. The most impactful change of MIFRS for PEG's research is in the area of capitalization policy. With few exceptions, the OEB required a capitalization policy consistent with MIFRS by 2013 regardless of when MIFRS was fully adopted. Hydro One was permitted to use US GAAP but had previously used Canadian GAAP so a change in its capitalization policy may have occurred during our sample period. In lieu of examining every LDC to determine the exact date changes to capitalization policy were made and the magnitude of the impact, PEG chose to restrict data to the post-2012 period for all sampled Ontario distributors.

   The tables below reproduce Tables 6 and 7 from the June report when the total and OM&A cost models were reestimated using enlarged datasets that included Hydro One's pre-2013 data. The pre-2013 data for the other Ontario companies are not included, thereby matching the samples for the original models.

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2013	-13.4%
2014	-9.4%
2015	-6.1%
2016	-5.7%
2017	-5.7%
2018	-2.4%
2019	*3.2%*
2020	*2.1%*
2021	*4.7%*
2022	*5.6%*
2023	*4.8%*
2024	*4.2%*
2025	*4.8%*
Annual Averages	
2013-2018	**-7.1%**
2016-2018	**-4.6%**
2021-2025	**4.8%**

Note: Italicized numbers are projections/proposals.

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

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2013	-18.3%
2014	-11.3%
2015	-5.9%
2016	-7.2%
2017	-9.0%
2018	-0.4%
2019	*0.2%*
2020	*-1.6%*
2021	*-0.8%*
2022	*-0.7%*
2023	*-0.4%*
2024	*-0.2%*
2025	*0.1%*
Annual Averages	
2003-2018	**-8.7%**
2016-2018	**-5.5%**
2021-2025	**-0.4%**

Note: Italicized numbers are projections/proposals.

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

<u>M-HOL-9</u>

Reference: Exhibit M, p. 7; working papers

Preamble:

PEG states that one of its four larger concerns is that the calculation of capital costs for the utilities in Clearspring's econometric study sample is inaccurate. Clearspring uses 2002 as the capital benchmark year for the Ontario distributors. PEG uses 1989 as the capital benchmark year for Hydro Ottawa, but stated that it did not have time or budget to modify the benchmark year for the other Ontario distributors.

Questions:

a. Please verify that PEG used the 2002 capital benchmark year for the other Ontario distributors.

b. Please verify that, in using the 1989 capital benchmark year for Hydro Ottawa, PEG had to estimate the capital data throughout those years by assuming a retirement rate that was applied to all years between 1989 and 2002 and interpolating some of the gross plant data that was not available.

c. What retirement rate for plant from 1989 to 2002 did PEG assume to estimate the capital data for Hydro Ottawa? Please provide evidence that Hydro Ottawa's retirement rate was at this assumed level between 1989 and 2002.

d. Please verify that, if Hydro Ottawa's retirement rate is not actually at the PEG assumed rate, this would negatively impact the accuracy of the PEG capital cost estimations for Hydro Ottawa.

e. Please provide a table comparing Hydro Ottawa's capital costs from 2013-2025 using the 1989 benchmark year and the 2002 benchmark year.

f. Please provide a table comparing the annual values for the implicit capital stock deflator, the power distribution Handy Whitman Index for the North Atlantic region, and the final index used by PEG that was applied to the Ontario distributors.

g. Please verify that PEG in its calculations for Hydro Ottawa assumed plant additions for the utility were exactly the same in all years from 1989-1997, and then exactly the same again from 1997-2002. Please explain why PEG believes that this is a realistic assumption.

Response to M-HOL-9:

a. This statement is verified. Converting several of the other Ontario LDCs involved a correction for mergers in the IRM4 data. Since an earlier benchmark year would have had only a small impact on model parameter estimates and the budget for empirical work was particularly restricted, PEG did not undertake this task. It was, in contrast, a priority to use the preferable benchmark year for Hydro Ottawa because it was the subject of the study.

b. This statement is confirmed.

c. PEG estimated the value of retirements as 0.5% of the gross value of the beginning of year plant. This estimate was used because publicly-available data for the retirements of Hydro Ottawa for this period are not known to exist. Evidence of retirement (i.e. disposal) rates can be seen on more recent capital continuity schedules. In EB-2011-0054, the company provided capital continuity schedules for the years 2006-2012. The ratio of total disposals to opening balance averaged 1.87% over this period which is higher than the 0.5% assumed. This included three years with higher values (2008-2010) and four years of low values (2006-2007 and 2011-2012) Had 1.87% been used as the retirement rate assumption, estimated plant additions would have been higher and the Company's cost performance would have been worse. PEG does not claim that the higher value would be appropriate for the earlier period, but rather just notes that the assumed 0.5% value lies in the middle of subsequently observed values for the company.

Hydro Ottawa Retirement Rate 2006-2012

	Disposals	Opening Balance	Retirement Rate
2006	$ 506	$ 791,162	0.06%
2007	$ 318	$ 861,379	0.04%
2008	$ 26,295	$ 929,757	2.83%
2009	$ 69,275	$ 971,622	7.13%
2010	$ 26,726	$ 954,856	2.80%
2011	$ 1,099	$ 995,214	0.11%
2012	$ 1,174	$ 1,072,657	0.11%
Average			1.87%

source: EB-2011-0054 Exhit B2 Tab 1 Schedule 1 Attachment S

d. This statement is confirmed. The estimated plant additions will be inaccurate to the extent that actual retirements differ from the estimates. However, low estimates in some years will tend to be offset by high estimates in other years. Furthermore, since retirements are valued in historical dollars, they tend to play a sufficiently small role in the growth of gross plant additions that some inaccuracy is tolerable. It is also important to note that there is a lower bound to the plant additions implied by differences in gross plant because estimated retirements are added to net additions to get gross additions and the retirement rate cannot be negative. In the extreme case of a zero-retirement rate, the imputed plant additions for Hydro Ottawa would only be about 5% lower than those used in the study. To the extent that the retirement rate is higher than assumed, Hydro Ottawa estimated plant additions will be higher and cost performance worse.

e. Please see Attachment M-HOL-9 (e) for the requested data.

f. Please see Attachment M-HOL-9 (f) for the requested data.

g. This statement is confirmed. PEG notes that in Clearspring's 2002 benchmark year adjustment the same assumption of equal plant additions is implicitly made for a period of years equal to the average service life (e.g., 40 years) of the assets. Since the gross plant value of Hydro Ottawa is available in 1989 and 2007, PEG believes that accuracy is served by using this information to upgrade the estimates of gross plant additions between 1989 and 2002, and to reserve the assumption of equal additions over forty years to 1989 when it will have less impact on benchmarking results.

   Using our approach, Hydro Ottawa's gross plant additions were larger between 1989 and 2002 than they were using Clearspring's approach. Our estimate of the capital quantity index and capital costs in subsequent years was therefore higher than Clearspring's.

   PEG used a similar approach to early plant additions in their RRF work. They believed that an additional 13 years of better albeit imperfect data were preferable to a 2002 benchmark year adjustment that used even cruder assumptions about the previous 13 years. In other words, the 1989 to 2002 additions needed to be imputed and the only issue was how it should be done.

M-HOL-10
Reference: Exhibit M, p. 7
Preamble:
PEG states that one of its four larger concerns is that Clearspring's benchmarking model does not properly address the complex issue of density.

Questions:

a. In light of the fact that the Clearspring model included a density variable and density squared variable, please explain how Clearspring's approach did not properly address the issue of density.

b. Please verify that PEG essentially added two interaction terms to address density (A*N and A*D) relative to the approach undertaken by Clearspring.

c. Please verify that the A*N variable is statistically insignificant.

d. On page 38 of the Report, PEG states that Clearspring addressed PEG's prior concerns by reducing the number of quadratic and interaction terms. However, in PEG's alternative benchmarking model it adds three interaction variables (A*N, A*D, and PCTOH*PCTFOREST). Please reconcile the addition of three interaction terms, given that PEG had a large concern in the Toronto Hydro research that Mr. Fenrick included too many interaction terms to address urban congestion, based on the theory that adding these variables reduced the degrees of freedom.

e. Can PEG provide the underlying principle that it believes should be followed by the benchmarking researcher regarding the inclusion of interaction and quadratic terms?

f. Please provide the area value used for Hydro One Networks' Distribution in PEG's dataset and explain how PEG determined that value.

g. Did PEG modify any other utility observations besides Hydro One Networks for the area served variable?

h. Is PEG concerned that one of the three outputs in its model is static and cannot grow or change over time?

i. In light of the prior discussions on how to properly measure density in the distribution industry, given the lack of consistent data on line lengths and the identified issues with service territory area, does PEG have any other ideas or suggestions on how to better measure customer density? In PEG's opinion, would some other physical measure be better than the service area (such as the number of distribution substations or some other possible measure of density)?

j. Why is density thought of by PEG as an output rather than a business condition? What distinguishes it from other business conditions such as forestation or advanced metering infrastructure ("AMI") meters?

Response to M-HOL-10:

a. PEG intended the term "density" in the report to encompass all of the cost implications of service territory area and not just how area compared to customers served. If area served is a major dimension of output, its impact is properly measured by including area as an output variable in cost models and adding all of the associated second order terms. PEG's econometric research established that area was a highly significant cost driver in the total cost and capital cost model. The CU variable was nonetheless retained in the model since, despite shortcomings like those that Dr. Lowry discussed on page 40 of his June report, this variable may nonetheless capture a special dimension of area. However, the parameter estimate for CU was markedly lower than that for CU in Clearspring's model.

b. PEG acknowledges that its A*N and A*D variables are density variables but notes that it also included area and area squared variables, and a CU variable.

c. The A*N variable is the only one of the four area-related variables in PEG's total cost model that is statistically insignificant. It is customary in econometric cost modelling to include second-order output terms even if some have insignificant parameter estimates.

d. The additional interaction terms in PEG's model are those that commonly accompany an output variable. These variables reduced the need to include quadratic terms for the CU and density variables. PEG's alternative specification therefore involved only one extra second order term and did so following established research norms. Part of the problem with second-order terms for Z variables is that there are not enough degrees of freedom to include all of them. The lack of commonly accepted rules for including a subset invites strategic behavior and controversy.

e. Second order terms make the functional form of a model more flexible but also reduce the precision of all parameter estimates by diminishing the degrees of freedom. Second order terms for Z variables invite strategic behavior and controversy. It is accordingly desirable to limit use of Z variables with sensible rules. PEG generally avoids second order terms for Z variables. An exception is interaction terms that have statistically significant and plausibly signed parameter estimates. A quadratic term may occasionally be included if there is an especially strong argument for a nonlinear relationship.

f. PEG used the value of 651,974 square kilometers for the service area of Hydro One Networks. This was the sum of the service territories reported in the 2014 Yearbook of Electricity Distributors for Hydro One and the three distributors that Hydro One later acquired: Haldimand County Hydro, Norfolk Power Distribution, and Woodstock Hydro Services. The calculation of Hydro One's service territory is documented in PEG's working papers.

g. No. PEG considered modifying the value for Kansas City Power and Light but, lacking a defensible means for doing so, decided instead to exclude this company's data from the econometric sample.

h. A time-varying value for the area variable would aid econometric estimation of its cost impact and make it more useful for productivity trend indexes. It could also deal with situations where the service territory is fixed but the area that is *intensively* served is expanding. Had good transnational data been available on line miles PEG might accordingly have considered this alternative, since miles data do change over time with the area of a service territory that is intensively served. However, consistent data on line miles were not available for investor-owned US power distributors. Area is a solid alternative and is important enough to merit treatment as an output variable.

i. Please see the response to part h of this interrogatory.

j. PEG considers area to be an output variable because it is a scale-related business condition, unlike variables such as forestation, temperature, overheading, and the standard deviation of elevation. Cost theory focuses on the impact of input prices and output on cost because these are typically the two most important external cost drivers.

M-HOL-11
Reference: Exhibit M, pp. 8, 43, and 61-63; PEG working papers
Preamble:

PEG states that the OM&A productivity trend of the U.S. distributors is 0.27% and that this should form the basis for the productivity growth target for the OM&A revenue for Hydro Ottawa.

In addition, in its discussion of Hydro Ottawa's proposed 0% total factor productivity ("TFP") target, PEG states the following on page 43 of the Report: "We also wish to challenge the notion that a 0% base productivity target is necessarily appropriate for Hydro Ottawa."

However, there is nothing in the ensuing discussion in the Report that addresses the arguments provided by Hydro Ottawa in the utility's response to part (g) of interrogatory OEB-6. In this response, Hydro Ottawa provides reasons in support of the use of the 0% TFP – in particular, the determination by the OEB in a 2013 report that the appropriate industry-wide TFP for Ontario distributors was zero, and the affirmation of the 0% TFP in the context of proceeding EB-2017-0049 (i.e. Hydro One Networks' 2018-2022 Custom IR distribution rate application).

Questions:

a. In examining PEG's working papers, it appears that a different peak demand variable was mistakenly used in the productivity research but was not used by PEG in the total cost benchmarking research. This is an understandable error, seeing as PEG used the variables provided by Clearspring with very similar variable names. In the total cost model, PEG uses the five-year rolling maximum peak demand variable labeled as "maxpk5" in the dataset as the output variable. However, near the end of the code, when PEG is calculating the growth in the output index for the PFP trend, the output variable is switched to the maximum peak demand since 2005, labeled as "maxpk05". Please verify or correct Hydro Ottawa's understanding of this mismatch in output definitions between the benchmarking and productivity studies.

b. Please reproduce Table 9 found on page 62 of the Report using the same peak demand output definition (maxpk5) as PEG used in the three cost benchmarking models.

c. Did PEG take a simple average when calculating the productivity trend for the industry, or conduct an aggregation or weighted average approach, similar to what was conducted for the 4th Generation IRM productivity research? If the simple average approach was used, please explain the deviation from the 4th Generation IRM procedure.

d. Please verify that every other Custom IR electricity distribution application approved by the OEB to date has included a 0.0% productivity factor.

e. Please verify that the Price Cap IR productivity factor of 0.0% was determined on the basis of PEG's research on the Ontario industry productivity trend in the 4th Generation IRM proceeding.

f. Why did PEG believe it was most appropriate to base the productivity factor only on the Ontario industry in the 4th Generation IRM?

g. Why does PEG now believe that it is most appropriate to base the productivity factor for Hydro Ottawa only on the U.S. industry?

h. Please confirm whether PEG's challenging of the 0% TFP target takes into account the arguments provided by Hydro Ottawa in response to part (g) of interrogatory OEB-6.

i. Please confirm whether PEG agrees or disagrees with the OEB's determinations from its 2013 report and its Decision and Order in EB-2017-0049 **in** support of the 0% TFP.

j. Does PEG believe that the issues of MIFRS and the appropriate sample for productivity measurements would be better addressed in a generic proceeding, rather than in this proceeding, on account of the limited time and budget available to conduct thorough research on these important issues?

k. Please include the one Ontario distributor (Hydro One Networks) that did not shift to MIFRS accounting in PEG's productivity research, and report the new OM&A productivity trend for 2007-2017.

l. On what basis did PEG choose the start year of 2007 for the OM&A productivity trend?

m. Does PEG consider this 10-year trend a long-run productivity trend?

n. Please list any account exclusions that PEG made to the OM&A measure in the U.S. productivity trend.

<u>Response to M-HOL-11:</u>

a. PEG confirms that it used maxpk05 in its O&M productivity calculations. This was inconsistent with the maxpk5 variable used in the econometric work from which the output index weights were obtained.

b. The maxpk05 variable is a ratcheted peak variable which cannot decline whereas the maxpk5 variable is a variant that only ratchets over the previous 5 years and can decline. The PFP trend using the maxpk5 variable that is consistent with the econometric work was 0.19%, modestly below the 0.27% trend report on page 61 of the PEG's Report.

c. PEG took a simple average of the productivity trends of the individual distributors in the sample. In most of its recent productivity studies, PEG has decided between average and aggregate results based on the size of the company to which the research applies. The rationale for this approach starts from the premise that economies of scale are an important driver of productivity growth. The scale economies produced by a given rate of output growth can vary with company size. It is then desirable to have productivity results for companies of similar size.

   Aggregation gives more weight to productivity results for companies of large size. This can sometimes make productivity results unduly sensitive to the performance of a few companies. Averaging gives more weight to results for companies of smaller size. The size of Hydro Ottawa is large by Ontario standards but is well below the average for the full sample used in this study. For example, the table on page 46 of PEG's July report showed that in 2017 the number of customers served by Hydro Ottawa was only 34% of the sample mean.

   Regarding PEG's use of the aggregation approach in its RRF research, this approach was the preference of OEB staff and the RRF working group. Exclusion of Hydro One and Toronto Hydro from the TFP trend work made the aggregate results less sensitive to the TFP trends of a few large companies --- which could be poorly managed or face unusually unfavorable circumstances and which would, in any event, likely propose custom IR plans --- and more similar to the average results. With these exclusions the average is much more influenced by medium-sized LDCs. This sets better expectations for medium sized and smaller LDCs.

d. PEG is not able to confirm this statement because Custom IR plans for Hydro Ottawa, Kingston Hydro, and Horizon Utilities were outlined in settlement agreements which did not identify separate stretch and productivity factors. For example, Hydro Ottawa agreed to a 0.3% productivity/stretch factor in its previous Custom IR plan (EB-2015-0004).

e. The Board's determination of a 0.0% productivity factor was based on PEG's total factor productivity study and the Board's expectation of TFP growth going forward. The transition to MIFRS accounting complicated the productivity research and the choice of an appropriate TFP growth target. PEG further notes that it has proposed a 0.0%

productivity growth target in this proceeding should the CPEF apply to Hydro Ottawa's capital cost as well as its O&M revenue. The evidentiary record in this proceeding does not support an alternative TFP growth target.

f. Dr. Larry Kaufmann of PEG did recommend basing the X factor solely on Ontario productivity results in the RRF proceeding, considering the Board's interest in this approach. In the 3GIRM generic proceeding, however, PEG presented productivity results using US as well as Ontario data.

g. PEG believes that Ontario and U.S. data are both pertinent in setting X factors for Ontario power distributors. However, the existing productivity results for Ontario are now quite dated, and the focus of that study was on total factor productivity, not OM&A productivity. OM&A productivity was not discussed or reported. Calculation of a long-term OM&A productivity trend is complicated by the conversion to MIFRS accounting. Itemized data on OM&A salaries and wages are not readily available for all Ontario LDCs which would permit calculation of an OM&A input price index with time-varying cost share weights. Pension and benefit expenses are not itemized for easy removal, and pension expenses could be accorded variance account treatment in a future plan. Termination of Statistics Canada's Electric Utility Construction Price Index will complicate computation of the Ontario total factor productivity trend going forward. The Board has encouraged a higher productivity X factor for Custom IR.

   Taking these considerations into account, PEG supports the averaging of the OM&A productivity trends of sampled U.S. distributors in this proceeding --- using Clearspring's data to reduce controversy --- to set the X factor for Hydro Ottawa's CPEF if it applies only to OM&A revenue.

h. In its response to 1-OEB-6 g), Hydro Ottawa opined that the 4GIRM and the Hydro One Distribution decision (EB-2017-0049) settled the issue of the productivity growth target, and it should not be litigated in this proceeding. PEG did consider this line of reasoning but settled on an alternative view that it details in response to part g) of this interrogatory. The index in the Hydro One Dx decision did not apply only to OM&A revenue.

i. PEG has not been tasked by OEB staff in this proceeding with reconsidering the appropriate total productivity growth target for Ontario power distributors today. In the absence of new contested evidence, a 0% TFP growth target in keeping with recent Ontario precedent is sensible <u>if</u> the CPEF applies to Hydro Ottawa's <u>total</u> revenue requirement.

j. PEG would welcome reconsideration of the X factor and other aspects of the RRF in a generic proceeding. However, in the absence of such a proceeding, the PFP trend it calculates using US data is suitable for Hydro Ottawa if its CPEF applies only to OM&A revenue.

k. PEG did not have company-specific O&M cost share weights for Hydro One and had also previously decided to exclude pre-2013 observations from the benchmarking work for all Ontario distributors, as described in the response to part (h) of question 8. Despite these reservations, PEG has calculated in response to this question the PFP growth of Hydro One using the 70% labor weight used by Clearspring. An average annual growth rate of 0.37% per year for the same 2007-2017 period was calculated. This included the peak demand correction noted in response to part (a) of this question. If the 0.37% trend were included as part of the US sample, it would result in a small increase in the 0.19% trend reported in part (b) of this response.

l. 2006 is the first year for which Clearspring provided all of the data required for the OM&A productivity calculations.

m. PEG considers the eleven years of growth rate data available to be an adequate if not an ideal sample to calculate a PFP growth factor for Hydro Ottawa. A sample period of this length has been used on several occasions in PBR proceedings to establish X factors where longer sample periods were not readily available.

n. The definition of OM&A was consistent with what was used in the PEG benchmarking work as discussed in its July report.

M-HOL-12

Reference: Exhibit M, pp. 8, 32-35, 62

Preamble:

PEG states that cost theory and index logic support use of a scale escalator (G) in a revenue cap index. Hydro Ottawa put forth a G that was substantially reduced from its projected customer growth. Rather than projected customer growth of over 1%, the company is only requesting a G of 0.4%. In Section 3 of the Report, PEG provides the indexing rationale that supports escalating the revenue cap by the growth in customers. PEG also provides Table 1 on page 35 which implies that the markdown in G that the utility proposed would be the largest markdown of the listed approved revenue caps that included a scale escalator.

Questions:

a. Please verify or correct the statement in the preamble above.

b. Absent Hydro Ottawa's proposal of 0.4%, what would PEG's recommended G factor be in this case?

c. In PEG's opinion, would a scale escalator equal to the growth in customers be a reasonable one?

Response to M-HOL-12:

a. This statement is confirmed.

b. Because Hydro Ottawa included a scale escalator in its proposed revenue cap index ("RCI"), PEG discussed the rationale for such an escalator at some length in Section 3.1 of its Report. PEG showed that the inclusion of a scale escalator in the design of an RCI is consistent with cost theory. Inclusion is more important to the extent that the output growth of the subject utility is expected to be brisk during the multiyear rate plan. A G factor can reduce the need for supplemental capital revenue, which frequently involves high regulatory cost and weak performance incentives.

   The escalator can, in principle, be multidimensional in the sense of summarizing the growth in multiple scale variables. Econometric estimates of the cost elasticities of the scale variables can be used to weight variables. In our revised total cost model, for example, there are two time-variant output variables (ratcheted peak demand and the number of customers served) and a time-invariant variable (area). Their respective estimated cost elasticities are 0.280, 0.656, and 0.068. Their respective elasticity weights are 27.9%, 65.3%, and 6.8%.

Scale variables chosen for inclusion in a scale escalator should be important drivers of utility cost. For gas or electric power distributors, the most sensible candidates are line length, ratcheted peak demand, and the number of customers served. The number of customers served has been most widely used as a scale variable in revenue cap indexes approved to date. It is an important driver of distributor OM&A and capital costs and is highly correlated with other scale variables such as peak demand and line length. The precedents for using customers as an RCI scale escalator include a multiyear rate plan for Enbridge Gas Distribution in Ontario.[7]

There are several possible rationales to applying a "scaling factor" to scale variable growth in an RCI.

- If output is multidimensional, the expected growth rate of one or more of the scale variables may be zero during the sample period. For example, ratcheted peak demand might not grow due to a slow economic growth and/or an aggressive CDM program. It may then make sense to mark down the growth in customers rather than going to the bother of developing a multidimensional scale index.
- The regulator may not wish to encourage growth in system use by including a usage variable in the scale index.
- The impact of output growth on cost may be expected to be considerably lower in the short run than in the long run. One possible reason is that load growth is expected to occur only in areas where there is ample capacity (e.g., power lines and substations) to accommodate it.

Consideration of scale economies is generally a *false* rationale for a scaling factor since scale economies are a component of TFP growth.

Hydro Ottawa has historically experienced steady demand growth that is fairly brisk by modern North American standards. The Company is in the process of building a large new MTS to accommodate load growth. It cannot be said that the marginal cost of demand growth is unusually slow. Peak demand growth may, however, be slowed by CDM programs. The proposed scaling factor on customer growth is therefore on the low end

[7] EB-2006-0615.

of the reasonable range considering PEG's estimate of the cost elasticity of customer growth

c. Please see the response to part b) of this interrogatory.

<u>M-HOL-13</u>
Reference: Exhibit M, p. 41
Preamble:
PEG states that Clearspring's estimation procedure did not correct the parameter estimates for autocorrelation and was therefore inefficient.

Questions:

a. Please provide an academic journal article citation which clearly states that the popular Driscoll-Kraay method used by Clearspring is inefficient on unbalanced panel datasets of the sort used in this research in comparison to the estimation method used by PEG.

b. Did PEG use a feasible generalized least squares ("FGLS") estimation approach for each of the three cost models?

c. Did PEG use the same modeling estimation approach that it used in the recent Hydro One Networks Transmission application?

d. Will this be PEG's standard estimation approach for future benchmarking models?

e. Does PEG believe that its parameter estimates are more accurate because of this procedure, relative to those of Clearspring? If so, please provide a citation detailing this assertion.

f. Please provide a step-by-step explanation of PEG's estimation procedure with steps on how to replicate it using STATA.

g. It is noted that the time dimension in the dataset (T) is smaller than the cross-sectional dimension (N). On this matter, Hydro Ottawa and Clearspring wish to draw attention to the following journal article, in which the author states the following:

> *In an early attempt to account for heteroskedasticity as well as for temporal and spatial dependence in the residuals of time-series cross-section models, Parks (1967) proposes a feasible generalized least-squares (FGLS)–based algorithm that Kmenta (1986) made popular. Unfortunately, however, the Parks–Kmenta method, which is implemented in Stata's xtgls command with option panels(correlated), is typically inappropriate for use with medium- and large-scale microeconometric panels for at least two reasons. First, this method is infeasible if the panel's time dimension, T, is smaller than its cross-sectional dimension, N, which is almost always the case for microeconometric panels. Second, Beck and*

> *Katz (1995) show that the Parks–Kmenta method tends to produce unacceptably small standard error estimates.*[8]

Furthermore, in that same section, the author states the following:

> *Therefore, Driscoll and Kraay's approach eliminates the deficiencies of other large-T–consistent covariance matrix estimators such as the Parks–Kmenta and the PCSE approach, which typically become inappropriate when the cross-sectional dimension N of a microeconometric panel gets large.*

PEG appears to use the "PCSE" command in STATA (discussed in the paragraph above) for its estimation approach. In light of these findings, please explain why PEG believes its estimation approach is more appropriate than the Driscoll-Kraay approach taken by Clearspring.

<u>Response to M-HOL-13:</u>

a. PEG is not aware of journal articles that are specific to this question since articles concerning the Driscoll-Kraay method typically compare it to other (and more widely used) estimators of *standard errors* such as Newey-West, White, and Rogers. These are types of "robust" standard errors, referred to as such because they modify the standard errors to be robust to various types of correlation. Those four types of robust standard errors are first discussed in the journal article referenced by Clearspring in the context of a pooled OLS approach to the estimation of model regression coefficients (aka "parameters" or β_j coefficients) rather than a modeling approach, such as feasible generalized least squares ("FGLS") estimation, which exploits the time structure of the data. The article next compares the robust standard error estimators to that resulting from the Parks-Kmenta method of FGLS estimation (which involves panel-specific autocorrelation coefficients) and the Beck-Katz PCSE method of standard error estimation, neither of which are used by PEG.

Comparisons of OLS to FGLS estimators of regression coefficients such as the Prais-Winsten estimator (which involves a *common* autocorrelation coefficient and is proven

[8] Daniel Hoechle, "Robust standard errors for panel regressions with cross-sectional dependence", *The Stata Journal*, Volume 7, Number 3, page 284 (2007).

to be a consistent estimator of the true autocorrelation coefficient - for all panels) are more readily available. For example, in his widely-used textbook, Wooldridge examines OLS vs. Prais-Winsten estimation approaches in chapter 12.[9] He states that

> "[the FGLS estimator] is asymptotically more efficient than the OLS estimator when the AR(1) model for serial correlation holds."

FGLS was developed to make full use of the sequential nature of time series data, and it remains a common econometric procedure. It is particularly popular in econometric forecasting due to its greater precision. Wooldridge's 2012 textbook presents substantial information on serial correlation, FGLS, AR1 processes, and pooled OLS estimation with alternative standard error estimators, but does not present the Driscoll-Kraay approach to standard error estimation.

OLS vs. FGLS is a complicated question for time series data depending on the goals of the modeling exercise, and there is room for professional judgement. There are numerous recent papers comparing OLS and FGLS which conclude that FGLS is preferred for many applications. PEG uses the Prais-Winsten FGLS approach because it takes full advantage of the data's time-series information - resulting in more accurate predictions across the entire sample - and avoids the Parks-Kmenta FGLS issues with unbalanced and short time series data. The Prais-Winsten FGLS approach with heteroskedasticity correction of standard errors is appropriate on both balanced and unbalanced panel data.

b. Yes. PEG used a Prais-Winsten estimation approach in all three models, and additionally corrected the standard errors for heteroskedasticity.

c. PEG used a Prais-Winsten estimation approach with heteroskedasticity-corrected standard errors in the Hydro One Networks Transmission application. However, the Hydro One Tx work was done in R while PEG's work in this proceeding was done in Stata.

d. PEG is likely to continue using a Prais-Winsten estimation approach with heteroskedasticity correction of standard errors but is always open to improving its econometric methods, when justified.

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[9] Wooldridge, Jeffrey M. "Introductory econometrics: a modern approach (upper level economics titles)." *Southwestern College Publishing, Nashville, T ATN* 41 (2012): 673-690.

e. PEG uses the time series structure of the data in its estimation procedure and removed much of the serial correlation from the error term, while Clearspring converted the time-series data into cross-sectional data only, leaving the serial correlation in the error term and adjusting the standard error to reflect this. Discussions of the merits of each approach can be found in the Wooldridge text referenced in part (a) of this question, and in numerous recent articles.

   It should also be noted that PEG's parameter estimates used in prediction produce a substantially lower Root Mean Squared Error ("RMSE") than Clearspring's model. The RMSE is the standard deviation of the variance of the residuals and is a central consideration in forecasting exercises.

f. Please see the working papers which include the Stata do-files for replication.

g. Clearspring and Hydro Ottawa may be misunderstanding the journal article and conflating coefficient estimators and standard error estimators. The first paragraph is irrelevant as it discusses the Parks-Kmenta estimation approach, which PEG did not use. In between the two paragraphs quoted above, the author states:

   "To mitigate the problems of the Parks–Kmenta method, Beck and Katz (1995) suggest relying on OLS coefficient estimates with panel-corrected standard errors (PCSEs). In Stata, pooled OLS regressions with PCSEs can be estimated with the xtpcse command."

   While the Parks-Kmenta specification is an option in the commands PEG uses in Stata and R, PEG does not use it. The author makes it clear he is referring to use of the xtpcse command option for standard errors using a <u>pooled OLS approach</u>. PEG opts to exploit the panel structure of the data with a Prais-Winsten estimator and does not use a pooled OLS estimator. The second paragraph is discussing covariance matrix estimators for the standard errors, not the estimation approach for regression coefficients. This is further confirmed - note the reference to covariance estimators, which are the source of the standard errors - along with an acknowledgment that Driscoll-Kraay standard errors often remain a bit too small (resulting in t-statistics that are too large), on page 2 of the paper Clearspring cites:

   > "Although Driscoll and Kraay standard errors tend also to be slightly optimistic, their small sample properties are significantly better than those of the alternative covariance estimators when cross-sectional dependence is present."

The authors make a case for using Driscoll-Kraay standard errors when estimating models via pooled OLS. These findings say nothing about PEG's actual estimation approach. Serial correlation is a statistically-identified problem in these data. Using an estimator designed for time series panel data and accounting for the serial correlation is a reasonable approach. It is a matter of professional judgement whether to ignore the time structure and pool the data as Clearspring does vs. exploit the time structure of the data in the interest of accurate coefficient estimates as PEG does. Both options (and of course, there are more than these two options) have arguments for and against depending on the goal of the modeling exercise, and both options have econometric theory and clear automated procedures (easily replicated by econometric software) for estimating them. PEG also notes that Clearspring's preferred Stata command for Driscoll-Kraay standard errors can be used with WLS estimation with fixed effects; pooled OLS is not the only available estimation approach.

Some of Clearspring's other claims about Driscoll-Kraay in comparison to PEG's method are not borne out in the literature. In their paper presenting the Driscoll-Kraay method of computing standard errors[10], Driscoll and Kraay state:

> Our results on consistency are based on asymptotic theory which requires the time dimension, T, to tend to infinity. Thus, our results will only be relevant for panel data sets in which the time dimension is reasonably large (our Monte Carlo simulations suggest that a value of T=20 or T=25 is the minimum).

In EB-2019-0261 IRR OEB-29 part g., Clearspring and Hydro Ottawa suggest that Driscoll-Kraay is appropriate even for T=5. The academic paper they provide tests the performance of White, Rogers, Newey-West, and Driscoll-Kraay standard error estimators for pooled OLS estimators with and without fixed effects. The "very small T" tests examine which of those particular standard error estimators works best in those highly unideal conditions. It is not a practical or theoretical defense of the consistency of the Driscoll-Kraay standard error specification in comparison to time-series approaches.

[10] Driscoll, John Christopher, and Aart Kraay. *Spatial correlations in panel data*. No. 1553. World Bank Publications, 1995.

<u>M-HOL-14</u>
Reference: Exhibit M, p. 41-43
Preamble:
PEG provides a list of smaller concerns regarding Clearspring's total cost benchmarking research.

Questions:

a. Did PEG use the same percentage forestation values and variable in its model as Clearspring used? If yes, how does PEG rationalize listing this as a concern, but then using the same variable? Should this also then be a concern with respect to PEG's work? If no, please indicate how the new variable was constructed and explain why PEG believes it is superior to the one used by Clearspring.

b. Did PEG adjust the number of gas customers in the percent electric variable? If yes, please list the changes made to PEG's dataset in comparison to the Clearspring dataset.

c. PEG indicates that including pensions and benefits in the Clearspring cost definition is one of its smaller concerns. Did PEG include the pensions and benefit expenses in its cost definition? If yes, should this also be a concern with respect to PEG's work?

d. PEG mentions that Clearspring's data was incorrectly mean-scaled. Please describe in greater detail what PEG believes was performed incorrectly by Clearspring. Seeing as all of the data is divided by the same denominator, will this have a meaningful impact on the study results?

e. Did PEG use Hydro Ottawa forecasted plant additions that are different than what Clearspring used? If yes, please provide the source and data used by PEG.

f. Did PEG update the Conference Board inflation forecasts to benchmark Hydro Ottawa's forecasted costs? If yes, please provide the annual growth rate percentages used for labour, non-labour, and capital input prices.

g. PEG mentions a concern regarding Clearspring using the U.S. GDPPI and adjusting for the Canadian PPP for the non-labour input price for the Ontario distributors. It is Clearspring's understanding that PEG uses the Canadian GDPIPI for final domestic demand for the Ontario distributors. Please verify or correct that understanding.

h. How is the levelization that accounts for the price and currency differences between the Canadian GDPIPI and U.S. GDPPI conducted by PEG?

Response to M-HOL-14:

a. Yes. PEG used the same forestation variable as Clearspring despite its concerns because it is the best forestation variable available. The concerns that PEG raises about this variable therefore apply to its own work.

b. Yes. PEG added gas customer data where Clearspring had incorrectly reported zeros. The observations that were changed and the data used to replace the zeros are provided in the working papers in the SST code and the YNG.xls file. These files were included in the PEG working papers.

c. Yes. PEG included pensions and benefit expenses in its cost calculations because Hydro Ottawa did not provide the data that would be necessary to exclude these costs. The concerns that PEG raises about this variable therefore apply to its own work.

d. The denominator used by Clearspring included observations that were not part of the final sample. Because the inclusion of the extra data affected the mean-scaled variables differently, the model parameter estimates changed slightly. Please see the SST code for the corrections to make it consistent. PEG does not know the impact of this change in the final model. It was small in PEG's earlier runs.

e. Yes. PEG relied on Hydro Ottawa's proposed/projected plant additions from the fixed asset continuity schedules as filed as Attachments D-J to Exhibit 2/Tab 2/Schedule 1 as updated May 5, 2020. These data were included in the SST code in the PEG Working Papers.

f. Yes. PEG made several changes to the inflation forecast, including the incorporation of the latest Conference Board of Canada forecasts, relying on the OM&A price index weights proposed by Hydro Ottawa, and calculating the inflation factor for the CPEF in the same manner as Hydro Ottawa. These forecasts were used to develop the input prices and PEG's version of the CPEF escalator. For each year, Hydro Ottawa calculated the growth in the inflation factor of the CPEF for each year as the average of the growth between 2017 and 2025. PEG replicated this approach in its work and the value relied upon a value of 2.24% for the inflation factor of the CPEF. To the extent that inflation forecasts were not available for the later years of this period, the values for the final year for which forecasts were available were repeated (e.g., data for 2024 were used for 2025, since the forecast did not extend to 2025). The growth rates for the labor, non-labor, and capital input prices were allowed to vary by year and are hardcoded into the SST code in the PEG Working Papers.

g. When doing this sort of transnational benchmarking work a researcher is faced with the problem of how to best construct consistent prices that accurately reflect both trends and levels. It is difficult to simultaneously do both. Suppose that the GDPPI for each country is the best available summary measure of summary material and service (“M&S”) price inflation. Clearspring chose to apply a currency-adjusted US GDPPI to the Canadian companies in its sample by multiplying the US GDPPI by PPP in each year. One problem PEG has with this method is that the resulting price index no longer reflects the growth in GDPPI for Canada.

The PEG approach is to believe that each trend index accurately reflects the trend for each country and not modify it. Using the Canadian GDP-IPI also controls for some inflationary impacts from currency changes. To the extent that some intermediate goods and services are imported from the US to produce final goods and services in Canada, a devaluation of the Canadian Dollar vs. the US Dollar will increase cost of production and some portion of this will flow through to prices. The PEG approach controls for the differences in levels in a single year and then adjust the values using the trend index. This method is not free of problems, but PEG believes it is better.

However, when preparing this response PEG noticed that it did not implement its method as it planned. The substitution of the GDPIPI for the US GDPPI was done, but the single year levelization was not implemented in the code and the Clearspring method was retained. The corrected code is reported below. Please see Attachment M-HOL-14 for the revised econometric models and cost performance tables and figures. These results also reflect inclusion of the three gas customer observations discussed in PEG’s response to part g) of the response to HOL-8 (Exhibit L/Tab 1/Schedule- 8). The capital cost model is unaffected by the concerns raised in this question, but the results are provided here to show the impact of the issue raised in question 8. As can be seen, the differences in cost performance resulting from these corrections are small.

```
range
range if[snlid<100]
range if[year<2018]
rem ^^^^^^^^ PEG Code Correction 7/5  ^^^^^^^^
rem Levelize Canadian M&S price relative to US by multiplying each observation by
rem a constant equal to (US GDPPI / CAN GDPIPI) x PPP in 2012
rem This adjusts the base year of each index and keeps each trend index intact
rem while accounting for currency differences
rem We chose 2012 as it was in the middle of the historical period considered and the PPP
rem was in the middle of the range of values for period
rem
set wm = gdppi*(1.05215/1.000) * 1.24461
rem ^^^^^ End
```

h. Please see the response to part g) of this interrogatory.

M-HOL-15
Reference: Exhibit M, p. 43
Preamble:
PEG mentions that the Ontario data has limitations for the accurate measurement of productivity trends. These purported limitations include the recent benchmark year for capital cost calculations, the recent transition to MIFRS accounting, and the fact that pension and benefit expenses are not readily excluded from such studies.

Questions:

a. What expense category exclusions to the OM&A cost definition did PEG make in its OM&A productivity research for the U.S. industry?

b. Please verify that the benchmark years for the capital cost calculations for the Ontario industry are approximately seven years older now than when PEG conducted and supported its productivity research for purposes of the 4th Generation IRM.

c. Has PEG reevaluated and changed its opinion regarding the robustness of its research for 4th Generation IRM, due to the issues raised in the current proceeding? Are these same issues relevant for the OEB's annual total cost benchmarking exercise?

d. Does PEG now believe that the productivity target for Price Cap IR should be based on a U.S. only dataset, rather than the Ontario only productivity result produced by PEG in 4th Generation IRM?

Response to M-HOL-15:

a. PEG made the same cost exclusions as in the benchmarking work. This differed from what Clearspring had done by subtracting street lighting maintenance instead of structure maintenance.

b. This statement is confirmed. PEG notes in this regard that it was reasonable at the time of the RRF proceeding to calculate TFP trends using Ontario data even if the benchmarking year was fairly recent. Also, PEG employed a 1989 benchmark year for most companies in this research.

c. PEG has never been asked by the OEB to reconsider the validity of its 4GIRM research or the appropriate TFP growth targets and benchmarking models for Ontario distributors going forward. Having learned many things since that proceeding, and developed increasing concerns about some Canadian data, PEG would doubtless do some things different if asked to redo these studies. Some of the same issues discussed here (e.g. MIFRS) would be confronted in any reconsideration of appropriate productivity and benchmarking methods.

d. Please see the responses to interrogatory Hydro Ottawa-11 (Exhibit L/Tab 1/Schedule 11) for PEG's views on this matter.

M-HOL-16
Reference: Exhibit M, p. 46-47
Preamble:
PEG states that it employed a critical value that is appropriate for a 75% confidence interval.

a. How did PEG determine this critical value?

b. It is Clearspring's understanding that past PEG studies have used a critical value of 90%. Please verify or correct this understanding. Please provide an explanation.

c. Will this be PEG's standard critical value for future benchmarking models?

Response to M-HOL-16:

a. In econometric research, there are several arguments for keeping a variable in a model if its inclusion is supported by economic theory and casual empiricism even if the parameter estimate is statistically insignificant.

   - If the variable is related to other variables in the model and they together test as jointly significant
   - For transparency in eschewing data mining (aka "significance fishing")
   - If it is the best available variable to capture the (theoretically supported) effect in question, including it in the model is reducing bias in the model by removing the associated data from the error term

   On the other hand, a rule that benchmarking models have statistically significant and plausibly signed parameter estimates guards against strategic behavior and the inclusion of too many variables (overfitting the model). PEG has developed the view that a 75% confidence level strikes the right balance between these considerations.

b. PEG has in the past used a 90% confidence level but is now using a 75% confidence level. This will be our decision rule until and unless a better one is developed based on new information and reasoning.

c. Please see the response to part b) of this question.

M-HOL-17
Reference: Exhibit M, p. 49-53
Preamble:
PEG provides its econometric cost models.

Questions:

a. PEG did not include the quadratic variable for percent congested urban that was included in Clearspring's total cost model. PEG did, however, include this quadratic variable in its OM&A model. Why was this variable excluded from PEG's total cost and capital cost model?

b. PEG did not include the extreme weather variable that was included in Clearspring's model and was included in PEG's total cost benchmarking research in the Hydro One Networks Distribution case. Why was this variable excluded from all three of PEG's cost models?

c. The standard deviation of elevation is included in PEG's total cost and OM&A model but not the capital cost model. Why was this variable excluded from the capital cost model?

d. Please describe the process that PEG undertook in developing the OM&A and capital cost models. Please explain why the three models contain different variables, and whether this was a systematic process of elimination starting from the total cost model or some other approach.

Response to M-HOL-17:

a. Since use of the area variable was not strongly supported by the data in the OM&A cost study, degrees of freedom were available for an alternative density specification. There are grounds for believing that the relation of cost to density is non-linear. In the other two models, there was strong support for an area variable and associated second order terms.

b. Using the Prais-Winsten estimator, PEG considered Clearspring's extreme weather variable and decomposed it into its heating degree day ("HDD") and cooling degree day ("CDD") components. They found that the HDD variable had negative (and often insignificant) parameters estimates in the total cost model, which is contrary to expectations. The CDD variable and Clearspring's summary severe weather variable had positive but statistically insignificant estimates. Based on these results, PEG did not include weather variables in any of its cost models.

c. The elevation variable was found to be significant at the 75% confidence level with the revised capital cost data and is included in the revised capital cost model that is presented in attachment M-HOL-14 (g).

d. PEG tried to improve its opex and capital cost models with a limited budget by adhering to sensible rules for model development. We started from the premise that all of the variables that were found to have statistically significant and sensibly-signed parameter estimates in the TC model merited consideration in the other two models even though they could have a different cost impact. Additionally, the OM&A cost model can in principle include variables that measure attributes of the capital quantities (e.g., the pervasiveness of overheading) which might be considered variables in the other two models.

   We found that some of the variables in the total cost model were not supported by the data for the other two models. Some variables were supported by the data but had a different cost impact. For example, in the OM&A cost model customers had a considerably higher cost elasticity and peak demand had a considerably lower elasticity than in the total cost model. We also found support for overheading variables in the OM&A cost model. All three models had high explanatory power.

M-HOL-18

Reference: Exhibit M, p. 64-89

Preamble:

PEG discusses several other issues related to the design of Hydro Ottawa's Custom IR plan.

Questions:

a. Given the combination of the negative TFP found within the Ontario distribution industry by both PEG and Mr. Fenrick, the productivity factor set at 0.0%, and the presence of stretch factors, does PEG believe that Price Cap IR is fully compensatory for the average Ontario distributor?

b. If the productivity factor was allowed to be negative would this, in PEG's view, reduce either the need for Custom IR or the size of the requested additional capital necessary to operate the utility?

c. Has PEG conducted any analysis on Hydro Ottawa's capital plan to determine if the capital projects proposed by the utility are necessary and reasonable?

d. PEG states that there is a risk that Hydro Ottawa will be overcompensated in the future once the capex surge is completed. Does PEG believe that this future risk will be mitigated to some extent by the 0% productivity floor plus the presence of stretch factors based on total cost benchmarking?

e. After a capex surge, the total cost benchmarking results for the utility will likely worsen as more capital costs enter the analysis. Does PEG believe this imposes a future cost on a utility undertaking a capex surge?

f. PEG states the following on page 67 of the Report: "Under Hydro Ottawa's proposal, customers therefore would never receive the full benefit of the industry TFP trend, even in the long run and even when it is achievable." Given the productivity factor has been set above the actual industry TFP and stretch factors are asymmetrically set at or above 0%, can PEG provide the basis for this statement?

g. On page 73 of the Report, PEG mentions the S factor in the Hydro One Networks Transmission case. Please verify that, based on PEG's calculations and responses in that case, with a stretch factor of 0.3%, the S factor that achieved parity with ACM and ICM was at or very close to 0.0%.

h. On page 74 of the Report, PEG mentions the possibility of separating OM&A productivity and Capital productivity, and that this may help alleviate or reduce the need for capital funding above what is provided for in Price Cap IR. Please verify that this statement would only be true in the current context if the capital productivity factor was allowed to go below zero to match the capital productivity trend within the industry.

i. PEG cites the capital variance account treatment as the single leading cause of the weak capital incentives in Hydro Ottawa's plan. What percentage would PEG recommend that Hydro Ottawa be allowed to retain if the utility underspends on capex?

j. PEG mentions on page 87 of the Report a "repex requirement indicator" variable that it has constructed in other research. In PEG's research on the distribution industry, does PEG believe that aging infrastructure is creating the need for relatively large increases in capex for some utilities?

k. Please describe how PEG constructed the "repex requirement indicator" variable. Is this variable similar to a type of capital age variable that estimates the average age of the assets on a system?

l. Did PEG explore calculating this variable for Hydro Ottawa? If not, how would PEG suggest calculating such a variable?

<u>Response to M-HOL-18:</u>

a. PEG has never been asked by OEB staff to consider this complicated question and can provide no definitive answer here but notes the following.

> PEG reconsidered the productivity trend of Ontario power distributors in their report in the recent Hydro One Distribution proceeding.[11] While a full upgrade and update of the 4GIRM productivity work was not undertaken, PEG calculated a 0.05% MFP growth trend for the sampled Ontario distributors over the 2003-15 sample period.
>
> Price Cap IR has an ACM/ICM option and Z factors that can provide supplemental funding for capex surges.

[11] EB-2017-0049 Exhibit M1 pp. 14-17.

High fixed charges for small-volume customers, which are rare in other North American jurisdictions, reduce the risk to Ontario distributors of demand fluctuations and declining average use.

b. Yes, it would. The analysis of productivity drivers in Section 3.1 of PEG's Report suggests that negative productivity growth targets are sometimes reasonable. However, it is not clear whether a negative productivity growth target is reasonable for the typical Ontario LDC.

c. PEG did read some of Hydro Ottawa's capital cost evidence but was not asked by OEB staff to meticulously review and critique this evidence.

d. As suggested in the response to part a) of this interrogatory, PEG does not concede that a 0% TFP growth target is above the target that would result from conscientious new empirical research. Furthermore, there is a considerable likelihood that positive TFP growth would be achievable in the aftermath of a capex surge.

   As for stretch factors, a capex surge can raise a utility's stretch factor for many years and thereby reduce overcompensation. To the extent that there is a repex cycle, however, cost performance can also be unusually good and the stretch factor unusually *low* in the later stages of the cycle. Were a utility to alternate between Custom IR and Price Cap IR, it would then offer customers an alternation over the years between revenue growth that reflects markedly negative productivity growth, productivity growth with a fairly high stretch factor, and productivity growth with an average to low stretch factor. On balance, customers would not expect to enjoy the benefits of productivity growth with an average (e.g., 0.3%) stretch factor.

e. Please see the response to part d) of this interrogatory.

f. Please see the answer to part d) of this interrogatory.

g. This statement is confirmed.

h. This statement is confirmed.

i. PEG supports an incentivized capital cost variance account that would permit the company to keep a sizable share of the cumulative capex cost savings achieved. As a step up from the experimental Hydro One capital variance accounts, a company share of 30% seems reasonable.

j. Yes. This can be true for utilities that have an unusually large quantity of assets requiring replacement.

k. An important focus of PEG's recent research for the Hawaiian Electric companies has been development of an appropriate age variable for use in econometric cost research. To the extent that assets near and then exceed their average service lives ("ASLs"), cost tends to rise due to a greater need for repex (and higher maintenance costs if repex is postponed). If the need for repex increases, intuition suggests that MFP growth will slow.

Standardized data on the age of assets are, unfortunately, not readily available for a large sample of U.S. electric utilities. However, extensive data are available on the value of gross additions to various kinds of electric utility plant in numerous prior years. We have used these data to develop a repex requirement indicator ("RRI") for transmission and distribution ("T&D") assets.[12] This variable indicates how the need for T&D repex varies between utilities and changes over time.

The need for repex is modeled as a 13-year moving sum of the quantity of gross plant additions made ASL years ago, six years further into the past, and five years forward into the future.[13] For each asset j in year t-s let $VKA_{j,t-s}$ $VKA_{j,t-s}$ be the *value* of gross plant additions, $XKA_{j,t-s}$$XKA_{j,t-s}$ be the *quantity* of plant additions, and $WKA_{j,t-s}$ $WKA_{j,t-s}$ be the value of the corresponding regional Handy-Whitman indexes ("HWIs") of electric utility construction costs. The repex requirements index for asset class j in year t $("RRI_{j,t}")$ then has the formula

$$RRI_{j,t} = \sum_{s=ASL-6}^{ASL+6} XKA_{j,t-s}$$

[12] Such an indicator is more problematic to construct for generation because aging generating plants may not be replaced, and replacements that are made may have a markedly different character (e.g., coal-fired capacity might be replaced with a mix of gas-fired and wind-powered capacity).

[13] This particular formulation had the strongest statistical support.

$$= \sum_{s=ASL-6}^{ASL+6} {VKA_{j,t-s}}\Big/{WKA_{j,t-s}} = \sum_{s=ASL-6}^{ASL+6} {VKA_{j,t-s}}\Big/{WKA_{j,t-s}}$$

In work for the Hawaiian Electric companies, we calculated RRIs for transmission and distribution and then calculated the summary RRI for T&D by summing the separate T&D RRIs.

I. $RRI_{TD,t} = RRI_{T,t} + RRI_{D,t}$.

This variable receives strong support in our model of the total cost of vertically integrated electric utilities.

m. Despite the limited budget for empirical research in this project, PEG explored including this variable in its work in this proceeding and asked Hydro Ottawa in Interrogatory 1-OEB-31 to provide detailed data on gross plant value, gross plant additions, and accumulated depreciation for as many years as were available. In response, Hydro Ottawa provided data on these variables only back to 2014. Hydro Ottawa also expressed concerns about the comparability of data prior to 2014 due to its switch in accounting standards. Without the requisite data for Hydro Ottawa, using this variable in the benchmarking models was not feasible.