HYDRO ONE SAULT STE. MARIE IR #1

INTERROGATORY #1

Reference: Exhibit M1, page 2

On page 2, PEG states: "We have in past years done power transmission benchmarking and productivity studies…"

Please list and provide all power transmission benchmarking and productivity studies conducted by PEG.

Response to Hydro One SSM-1: The following response was provided by PEG.

PEG personnel have previously prepared statistical transmission cost benchmarking studies for two Australian transmission utilities, Powerlink Queensland and Transend. PEG's work for Powerlink Queensland was preliminary, privileged, and confidential, and thus PEG has submitted this report as a confidential attachment. A copy of the Transend report is Attachment PEG-HOSSM-1b. Between 2001 and 2003, PEG advised Hydro One Networks on PBR issues for transmission. This advice included productivity research commissioned but never made public by Hydro One. Copies of PEG's report are not publicly available but may still be in the possession of Hydro One. PEG considered the OM&A productivity of US power transmission utilities in recent research and testimony for the Association Quebecoise de Consommateurs Industriels d'Electricité in Quebec. A copy of PEG's report for AQCIE is Attachment PEG-HOSSM-1c.

INTERROGATORY #2

Reference: Exhibit M1, page 3 & page 39

On page 3 PEG discusses the Energy Policy Act of 2005 and how "reliability standards were established and enforced that raised costs for many utilities."

a. Please provide the basis for this assertion. Have transmission reliability metrics improved for the industry since 2005? If so, please provide the empirical data supporting this assertion.

b. On page 39, PEG notes that NERC established reliability standards called Critical Infrastructure Protection standards. Does PEG have any reason to believe that these standards would cease to apply over the Custom IR term of the PSE study (2019-2022)?

c. Is PEG aware that Hydro One is required by the IESO to comply with these same NERC reliability standards? If PEG's assertion is true that the standards raised costs for many utilities, would the more recent trend studied by PSE not be more reflective of reasonable p roductivity expectations for Hydro One over the Custom IR term (2019-2022)?

Response to Hydro One SSM-2: The following response was provided by PEG.

a. Prior to the implementation of the Energy Policy Act of 2005 reliability standards were voluntary. These standards were not approved by the FERC and did not lead to potential penalties for failures to comply. In the aftermath of the 2003 blackout that affected large swaths of the US and Ontario, the FERC was sufficiently concerned about existing reliability standards that it issued a policy statement in Docket PL04-5 in April 2004 in which it supported legislation to close gaps in reliability compliance. In this section PEG did not assert that reliability improved, but rather that costs increased for many utilities during this period.

   PEG's understanding is that, until recently, transmission reliability data were limited. The North American Electric Reliability Corporation provides some reliability data that includes years prior to and after the Energy Policy Act of 2005. Here are links to some notable web pages on various transmission metrics that show the reliability performance of the transmission industry on a handful of metrics. Performance on these metrics is skewed due to the 2003 Blackout.

   https://www.nerc.com/pa/RAPA/ri/Pages/BPSTransmissionRelatedEvents.aspx https://www.nerc.com/pa/RAPA/ri/Pages/UnderFrequencyLoadShedding.aspx

b. PEG anticipates that reliability standards will continue but has no reason to believe that they will become more stringent. If they did become more stringent, Hydro One might make a Z factor claim to receive supplemental compensation under its proposed IRM.

c. Yes. Please see our answer to part b of this question for an explanation of why Hydro One's conformance with NERC standards does not imply that PSE's short sample period is appropriate. The fact that cost was raised during PSE's sample period does not mean that they would be raised again.

INTERROGATORY #3

Reference: Exhibit M1, page 20 – Table 2

From Table 2 in the PEG report, PEG's U.S. MFP industry sample's output quantity index average annual growth rate for 1995 to 2016 is 0.91%. For the 2005 to 2016 period it slows to 0.72%. The industry's output quantity index slows even more from 2011 to 2016, at an average annual growth rate of 0.43%. The MFP results also get lower as the industry output growth slowed. From 1996 to 2016 the average annual industry MFP on PEG's Table 2 is -0.34%. From 2005 to 2016 it is -1.82%. From 2011 to 2016 it is -2.67%. On Table 3, the Hydro One output quantity has grown considerably slower than the U.S. industry, and the projected growth for 2019 to 2022 is 0.00%.

a. Does PEG believe the rapid industry output growth rates from the 1990s provide applicable information for determining the future productivity trend of a utility with the expected Hydro One output growth rate of near zero for the years 2019 to 2022?

b. Did PEG consider making an adjustment for the fact that PEG is using a sample period with far more rapid output growth than the Hydro One expected output growth will be for the period the X Factor will be applied? If yes, please provide what was considered. If not, please explain why an adjustment is not appropriate.

Response to Hydro One SSM-3: The following response was provided by PEG.

a. PEG agrees that growth in operating scale is a pertinent consideration in the choice of an X factor for Hydro One Transmission. However, scale economies are only one of several drivers of productivity growth and the impact of slowing output growth on productivity growth would not likely be large. The sum of the elasticities of the scale variables in the PSE model is 0.676 + 0.237 = 0.913. This suggests that, at a sample mean level of operating scale, a 100 basis point swing in operating scale growth has only a 8.7 basis point impact on MFP growth in the long run.

b. No consideration was made to making an adjustment for slowing output growth. Please see the answer to part a of this question for an explanation.

INTERROGATORY #4

Reference: Exhibit M1, page 3

PEG mentions a "structural change" in the U.S. transmission industry. PEG correctly mentions that many sampled utilities joined independent transmission system operators (ISOs) or regional transmission organizations (RTOs). PEG also claims that this will have materially impacted reported OM&A expenses. Most of the ISOs and RTOs in the U.S. were created and/or began market operations in the late 1990's and early 2000's. As PEG correctly states on p. 38: *Several ISOs were formed between 1996 and 2000. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the US. The Midwestern ISO (dba today as Midcontinent ISO) and PJM Interconnection were approved for RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004.*

This structural change occurs during PEG's 1996 to 2016 TFP and benchmarking sample and, specifically, prior to 2005.

a. Why, in PEG's opinion, does it enhance the expected Hydro One productivity factor to have such a significant structural change in the industry during the sample period rather than begin the sample period after this structural change?

b. PEG excludes several cost categories from the transmission total cost definition due to this structural change. Could other cost categories not excluded by PEG be impacted during the move to ISOs and RTOs during the late 1990's and early 2000's? Did PEG test cost categories to see how they were affected by the structural change? If so, please provide the details of this analysis.

c. We note that PEG excluded certain cost categories to avoid some of the cost changes from the structural change. Assuming the same transmission cost definition was employed as PSE, would PSE's sample period that begins after most of this structural change had already occurred be less susceptible to the ISO/RTO structural change than PEG's longer sample period? If not, please explain.

d. On p. 3 and p. 4 PEG states: "Exclusion from the calculations of costs that were especially sensitive to this restructuring produces considerably more rapid productivity growth estimates." The additional cost categories excluded by PEG that were not excluded by PSE are the Load Dispatching accounts, Transmission Rents, and Transmission Miscellaneous expenses. Please specify which account(s) this statement pertains to and provide the evidence PEG relied upon to justify the exclusion for each excluded account.

e. Is PEG aware of any changes or incentives that could reasonably expect to incent transmitters to move away from the ISO and RTO operating models in the Custom IR period (2019-2022)?

f. Is PEG aware that Ontario operates under an ISO model where the IESO acts as the ISO and Hydro One owns and operates its portion of the transmission grid? Please explain why the study period of the PSE analysis does not provide a better indicator of productivity expectations in the Custom IR term (2019-2022), given that the ISO structural change noted by PEG in its report primarily occurred prior to PSE's sample period thus providing a similar alignment of the US industry for the entire PSE sample period to what Hydro One will encounter in the Custom IR term.

Response to Hydro One SSM-4: The following response was provided by PEG.

a. PEG does not believe that choosing a period during which structural change in the industry was rapid is an advantage in a productivity study. PEG's choice of a sample period was prompted by other considerations that they believe it to be offsetting. They have tried to minimize the impact by removing the costs most affected by this change.

b. PSE had no grounds for believing that other cost categories were affected by structural change. PEG's decision to exclude two cost categories due to structural change concerns was based on reason, and our experience with transmission cost data in other projects. Please see the response to HOSSM-5(l) for additional evidence that structural changes affected these cost categories.

c. PSE and PEG both used common cost data for their transmission cost benchmarking and productivity research. Even if a shorter sample period helped with the productivity research it would not help with the cost benchmarking research.

d. The FERC accounts that were excluded due to restructuring concerns were those for Load Dispatching, Transmission by Others, and Transmission Miscellaneous Expenses. PSE also excluded Transmission by Others expenses.

e. No. However, this is not an argument favoring PSE's cost definition or sample period.

f. The fact that structural change chiefly occurred prior to PSE's sample period does not offset the fact that, during this period, the Energy Policy Act of 2005 was enacted and many transmission utilities moved to formula rates. These circumstances resulted in an acceleration of cost growth during these years that is unlikely to be repeated and has no counterpart in Ontario.

INTERROGATORY #5

Reference: Exhibit M1, page 13

PEG lists the excluded OM&A accounts as transmission by others (account 565), load dispatching (accounts 561-561.8), miscellaneous transmission expenses (566), and transmission rent expenses (account 567).

a. In examining the working papers, it appears that these same accounts that were subtracted from the U.S. sample were not subtracted for Hydro One. Please confirm these accounts were not subtracted from Hydro One's cost definition.

b. If some cost categories are included in Hydro One's cost definition but excluded in the U.S. sample's cost definition, please explain how PEG considers this to be a consistent cost definition between Hydro One and the U.S. utilities in the benchmarking sample?

c. If PEG did exclude the same costs for Hydro One to be consistent with U.S. sample, please provide the data source or method used to subtract these costs and provide the year-by-year amounts subtracted for Hydro One by each account. Please describe where the subtraction takes place in PEG's benchmarking and Hydro One TFP code.

d. If industry productivity is faster when these costs are excluded for the U.S. sample as PEG states on p. 3 an p. 4, this would seem to imply the costs PEG decided to take out of the U.S. cost definition grew faster than other OM&A cost categories not subtracted. How did the ISO/RTO structural change have the effect of raising costs for these accounts? How is this consistent with PEG's claim on p. 9 that "These agencies performed some of the functions that the utilities had previously undertaken"?

e. Please provide a table showing the industry aggregated amounts for each of these accounts for each year of the sample. Please also include Transmission OM&A and total costs by year for both the industry.

f. Please provide the percentage of OM&A excluded by PEG for all the load dispatching accounts, miscellaneous transmission expenses, and transmission rent expenses to the total OM&A used in the benchmarking study for the industry? Please provide this percentage by year.

g. Please provide a revised Table 2, Table 3, and Table 4 for each of the following changes when adding back in the following three exclusions (in (i) through (iii), only the one mentioned cost is to be added in so we can see the isolated impact of each decision to eliminate the cost category):

i. Transmission rents to PEG's total cost definition,
ii. Miscellaneous transmission expenses to PEG's total cost definition,
iii. All load dispatching accounts to PEG's total cost definition, and
iv. Please provide a revised Table 2, Table 3, and Table 4 if all three exclusions are added back into PEG's cost definition.

h. Please provide a revised Table 1 and Table 4 when restricting the econometric benchmarking sample to the years 2004 to 2016 and leaving all other methodologies and variables the same as conducted by PEG.

i. Please provide a revised Table 1 and Table 4 when restricting the econometric benchmarking sample to the years 2004 to 2016 and adding back all load dispatching accounts, miscellaneous transmission expenses, and transmission rents into the U.S. cost definition.

j. From FERC's website, in the Uniform System of Accounts (USoA) for electric utilities, miscellaneous transmission expenses are defined in the following way.

566 Miscellaneous transmission expenses (Major only).
This account shall include the cost of labor, materials used and expenses incurred in transmission map and record work, transmission office expenses, and other transmission expenses not provided for elsewhere.

Please explain why these costs are not appropriate to include in a transmission total cost benchmarking study or transmission TFP study.

k. In the Uniform System of Accounts (USoA) for electric utilities, transmission rent expenses are defined in the following way.

567 Rents.
This account shall include rents of property of others used, occupied, or operated in connection with the transmission system, including payments to the United States and others for use of public or private lands and

reservations for transmission line rights of way.

i. Please explain why these costs are not appropriate to include in a transmission total cost benchmarking study or transmission TFP study.
ii. Does the USoA definition state the rents paid need to be in connection with the transmission system?

l. Is PEG concerned that their studies may be excluding legitimate transmission costs that should be included in a total cost benchmarking study or total factor productivity study by excluding load dispatching, transmission miscellaneous expenses, and transmission rents?

m. Is PEG concerned that those same types of expenses may still be included in Hydro One's cost definition? If not, please explain.

n. In examining PEG's working papers, it appears PEG also excluded another cost category (Franchise Requirements, account 927) from the cost definition but we did not identify where this was discussed in the report. Please confirm this account was also subtracted from the U.S. utility cost definition. [Where are parts o through t of the question, if you provide the answers below?]

Response to Hydro One SSM-5: The following response was provided by PEG.

a. PEG confirms this statement and notes that they did not have the data required to make an explicit adjustment for Hydro One. For reasons explained in PEG's response to question 5 part l, they believe that the relative cost of miscellaneous transmission expenses will be smaller than that for US companies. Dispatching costs would be similar to those of US utilities that cooperate with ISOs and lower than those of US utilities that do not cooperate with ISOs. PEG invites Hydro One to provide these costs so that PEG's benchmarking study can be updated with these costs removed.

b. PEG acknowledges that the cost definition is not fully consistent, but they believe that inclusion of these costs in the data for US companies would not have improved the accuracy of the benchmarking results.

c. Please see the answer to part a of this question.

d. PEG removed Dispatching costs out of concern that they might be *reduced* for utilities cooperating in ISOs. Miscellaneous Transmission Expenses were, in contrast, removed out of concern that they might be increased by ISO participation. PEG's biggest concern was the inclusion of RTO charges. This is also a concern for Transmission by Others expenses which, in any event, are not pertinent to the benchmarking study.

e. PEG believes that PSE is capable of credibly producing this information without the assistance of PEG.

f. Please see the response to part e of this question.

g. PEG believes that this is an onerous and unreasonable request. Part 4 of the question is provided in response to part i of question 6.

h. Please see Attachment PEG-HOSSM-5h (a) and (b).

i. Please see Attachment PEG-HOSSM-5i (a) and (b).

j. Our main concern with miscellaneous transmission expenses was that utilities would "park" substantial ISO charges in this category. Under normal circumstances, the amounts would be expected for a miscellaneous account. We expect that this should also be the case for Hydro One.

k. Rents are expenses for renting and leasing assets which are paid over time and booked to O&M. In at least one case, this account was used for a rental cost for a significant amount of company-owned capital in a joint venture. The end result was that rents for PEGID 119 exceeded all other O&M expenses. This resulted in an in implausible trend in OM&A expenses and affected the productivity trend for the full sample. In the absence of a good method to move the rents to capital cost and quantity, we decided to exclude them for all companies. Excluding PEGID 119 was another option, but we wanted to keep the PSE sample intact. The USoA instructions do express the expectation that the rents would be transmission-related. We expect this item should be small for Hydro One as it is for most US companies.

l. This is clearly a downside of excluding these expenses. PEG is concerned with getting a reasonable long-term productivity trend corresponding to whatever scope of transmission cost can be well measured. As discussed in these responses, we felt it necessary to reduce the scope of that to owning, operating, and maintaining an electric transmission system. We implicitly assume that market-related activities such as dispatch have the same productivity trend as the core functions of the transmission operator.

The instructions for account 566 Miscellaneous Transmission Expenses call for the reporting of expenses that are not properly accounted for elsewhere. This would imply that the expenses in this category are not normal O&M expenses as described in the other accounts but something different. The nature of the examples given in the account description do not appear to suggest a high level of cost. It is therefore suspicious if we find very high levels of such expenses. PEG did an analysis of the PSE data for sampled companies. In 1995, prior to the establishment of RTOs, this category averaged 9.2% of PSE's definition of net transmission O&M cost (i.e. excludes transmission by others). By 2004, this percentage had doubled to over 20% and remained at over 18% in 2016. PEG's primary concern was not that this percentage had increased, but that for many companies it increased to implausible levels. In 2016, most companies still had miscellaneous transmission expenses that were less than 10% of net transmission O&M. However, the expenses for several had risen dramatically to 61%, 69%, 81% and 94% of net O&M. Four others had risen to a range of 43-45%.

PEG does not believe the fact that this increase happening at about the same time as RTOs were being established is coincidental. PEG has some anecdotal evidence that some of what is observed could be related to billing relationships with the RTOs. When run by an ISO, a transmission provider can also be a customer. This could possibly lead to an accounting situation in which a utility charges the RTO/ISO for the cost it incurs for its part of the regional transmission system. The company could then receive compensation that would be recorded as other operating revenues. For its own use of its transmission system, the company could be billed at tariffed rates. This bill would not cleanly fit into other accounts and could plausibly be placed in the miscellaneous account by some utilities. The "transmission by others" account is for payments for the use of systems owned by others and not company-owned assets. In this case, some of the transmission cost would be double counted, first directly through recording in the normal detailed FERC accounts and a second time though the miscellaneous account. This double counted cost is offset by transmission revenues received by the company.

Revisions to the FERC Form 1 also suggest that the FERC believed accounting for transmission cost needed clarification in the age of RTOs. An entirely new set of accounts for regional market expenses were added. Also added were many more transmission O&M accounts to provide more granularity for load dispatching and other costs associated with regional market activities. The other operating revenues category on page 300 now features an explicit decomposition of account 456 for regional control service revenues and revenue from transmission by others. For the four companies that had greater than 50% of O&M booked to miscellaneous in 2016, other operating revenues grew by 43%, 97%, 105%, and 206%.

PEG's analysis nonetheless supports the idea that there is something unusual happening with this account. It is PEG's opinion that the levels of cost reported in this account are not plausible in many cases and miscellaneous transmission O&M expenses should be excluded to obtain reasonable cost model parameter estimates and productivity trends.

m. PEG acknowledges that this is a valid concern with its cost benchmarking work.

n. PEG confirms that this (typically small or zero) expense was excluded since these expenses are tantamount to a tax.

INTERROGATORY #6

Reference: Exhibit M1, page 4

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

f. We comment below on each of these statements.

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

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

   iii. This statement is confirmed.

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

   v. This statement is confirmed.

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

h.

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

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

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

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

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

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

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

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

INTERROGATORY #7

Reference: Exhibit M1, page 5

On page 5 PEG states regarding the cost benchmarking results: "The short sample period unnecessarily reduced the accuracy of cost model parameter estimates."

a. What was the benchmarking sample period that PEG used in its benchmarking research for Hydro One Distribution in EB-2017-0049?
b. What was the benchmarking sample period that PEG used in its benchmarking research for 4th Generation Incentive Regulation in EB-2010-0379?
c. What was the benchmarking sample period that PEG used in benchmarking Toronto Hydro's total cost performance in EB-2014-0116?
d. PEG added nine historical years (1995 to 2003) to the benchmarking sample compared to PSE. The year 1995 is 27 years prior to the Hydro One cost benchmark for 2022 produced by PEG. These earlier years predated most of the ISO/RTO activity that is now present in the industry. The earlier years also displayed far more rapid output growth than Hydro One is projected to have during the Custom IR period. Does PEG believe that adding these pre-ISO/RTO observations adds to the accuracy of the 2020, 2021, and 2022 total cost benchmarks for Hydro One? If so, please explain.
e. Is the 13 years of data used by PSE sufficient to produce robust parameter estimates for a total cost model? If not, please explain.
f. Which sample period (1995 to 2003, or 2004 to 2016) contains data that is more reflective of the future output growth of the transmission industry for the next three years (2020, 2021, and 2022), in PEG's opinion?
g. Which sample period (1995 to 2003, or 2004 to 2016) contains data that is more reflective of the recent industry move to renewables (wind and solar) and the upward pressure on investment these renewables place on the transmission system, in PEG's opinion?

Response to Hydro One SSM-7: The following response was provided by PEG.

a. The sample period for PSE's benchmarking work for Hydro One was 2002-2015. PEG used the same sample period in this proceeding because it was not authorized by OEB staff to undertake an independent benchmarking study.

b. PEG was not authorized to use US data in its statistical benchmarking work for the OEB in the 4th

GIRM proceeding. Its sample was thus limited to the 2002-2012 period.

c. PEG used the same sample period that PSE used in that proceeding because it was not authorized by OEB staff to undertake an independent study.

d. Yes. A larger sample period increased the accuracy of econometric model parameter estimates and reduced the impact on the trend variable of the Energy Policy Act of 2008 and the increased use of formula rates in FERC transmission regulation. The trend variable in the econometric benchmarking model plays an important role in benchmarking costs that are several years into the future. PSE's estimate of the trend variable parameter using its shorter sample period is 1.29%.

e. PEG believes that it would be preferable to have a longer sample period. A shorter sample period like that which PSE uses would be reasonable only if results for earlier years unavailable and the data were not sensitive to changes to business conditions that are unlikely to occur during the years of cost forecasts.

f. The shorter sample period chosen by PSE is more reflective of future output growth. However, this is only one of several considerations that are important to the choice of a sample period. As we have seen, these considerations include the Energy Policy Act and the adoption by many utilities of formula rate plans.

g. Results for the shorter sample period might be more reflective of the move to renewables but the importance of this move and its pertinence for Hydro One is not well understood.

INTERROGATORY #8

Reference: Exhibit M1, page 9

PEG discusses the ISO/RTO structural change and that many U.S. electric utilities joined ISOs or RTOs in the "last twenty years."

a. Please provide a breakdown for PEG's sample on how many PEG sampled utilities joined an ISO or RTO in each sampled year.

b. How many sampled utilities joined an ISO or RTO prior to 2005?

c. How many sampled utilities joined an ISO or RTO after 2005?

Response to Hydro One SSM-8: The following response was provided by PEG.

a-c Please see Attachment PEG-HOSSM-8 for answers to these questions.

INTERROGATORY #9

Reference: Exhibit M1, page 12

PEG's says that their productivity sample includes 44 U.S. transmitters and 56 transmitters were used in PEG's econometric benchmarking research.

a. Please list any differences from PSE's sample and explain why the utility was either include or excluded.

b. Did PEG exclude utilities due to large transmission/distribution cost transfers similar to what PEG did in its alternative benchmarking research for Hydro One Distribution's last application in EB-2017-0049? If not, please explain.

Response to Hydro One SSM-9: The following response was provided by PEG.

a. There are no differences in the US sample.

b. PEG did not exclude utilities for this reason because larger samples have advantages and PEG's research to date has shown that such exclusions do not have much impact on results.

INTERROGATORY #10

Reference: Exhibit M1, page 13

PEG mentions that some utilities use the transmission rent account to report leases on facilities they jointly own.

a. Please provide the basis for this claim. Does PEG have any data or has PEG conducted any analysis which would indicate such practices would materially impact the outcome of the benchmarking or productivity analysis? If so, please provide.

b. If a lease is jointly owned by the transmission utility and a different entity, should at least a portion of the lease be attributed to the transmission utility's costs?

c. Does this imply that some utilities are not properly allocating facility costs to their transmission operations?

d. Would excluding transmission rents bias the benchmark results against a utility that tends to own its facilities rather than rent?

Response to Hydro One SSM-10: The following response was provided by PEG.

a. Please see the response to question 5k. The inclusion of rents would significantly change the productivity growth of one distributor (PEGID 119) in the PSE sample. PEG chose to remove rents as a category instead of removing the company from the sample.

b. PEG agrees that the cost should be included but prefer that the cost be treated as an asset.

c. PEG has not made this contention.

d. This is a potential concern but the impact would likely be quite small since this is not a large cost category for most utilities. In the case of PEGID 119, PEG made a corresponding reduction to their reported line miles, which included the jointly owned line.

INTERROGATORY #11

Reference: Exhibit M1, page 14

PEG describes the input prices used in the study.

a. Why did PEG escalate the U.S. cost by the employment cost index for the utilities sector, but then use average weekly earnings in Ontario for Hydro One?

b. Is the average weekly earnings measurement used by PEG specific to the utility industry?

c. Is PEG concerned, especially given how far removed a large portion of their older sample is from the input price levelizations, that measuring utility-specific labour inflation for the U.S. sample and a general economy labour inflation measure for Hydro One creates an inconsistency in the benchmark sample?

d. PEG uses the Handy Whitman indexes that are specific to the electric transmission industry for the U.S. sample, but then uses a capital stock deflator for the Canadian utility industry for Hydro One. This capital stock deflator includes the sectors of power generation, electric transmission, electric distribution, gas distribution, water, and sewer utilities. Does PEG believe that electric transmission capital price increases will match the capital price increases of all those other utility sector industries that are included in PEG's capital stock deflator index? If not, does this produce an inconsistency in the benchmarking sample between Hydro One and the rest of the U.S. sample?

e. Has PEG used Handy-Whitman indexes for productivity or benchmarking studies in past research on Canadian utilities? If so, please list and provide the studies.

f. What is PEG's rationale for not using Hydro One's rate of return on capital when calculating the industry productivity trend that will be applied to Hydro One?

Response to Hydro One SSM-11: The following response was provided by PEG.

a. Statistics Canada does not compute Employment Cost Indexes. AWEs are widely used in Canadian inflation research even though they do not have fixed weights.

b. No. Two arguments support PEG's use of the AWE for all Ontario businesses.

- Hydro One, as the largest power transmitter and distributor in the province, might influence on the utility-sector AWE.

- The AWE for the utilities sector of a single province is likely to be more variable than the AWE for all business in the province

- The OEB has elected AWE for all Ontario businesses as a component of the inflation measure for 4th GIRM.

c. PEG believes that this concern is small and is offset by the advantages of using the Ontario-wide AWE.

d. PEG did extensive work in the recent Hydro One Distribution proceeding (EB-2017-0049) on alternative asset price indexes to replace suspended Statistic Canada's electric utility construction price indexes. The index that they chose did a considerably better job of tracking the EUCPIs for power distributor assets than the index that PSE uses (Handy Whitman Index for North Atlantic Power Distribution x US/Canadian Purchasing Power Parity).

e. PEG used EUCPIs in several of its power distribution cost studies for the OEB. PEG did use Handy Whitman indexes in the Ontario Power Generation IRM proceeding and in its 2003 and 2004 benchmarking studies for Enbridge Gas Distribution. The 2003 and 2004 studies for Enbridge Gas Distribution and 2016 study undertaken in the Ontario Power Generation IRM proceeding are Attachments PEG-HOSSM-11e (a) and (b). In these applications we did not believe that the EUCPI would be satisfactory, and were not aware of the existence of alternatives prior to 2007. We first used an implicit price index for utility assets in a 2008 gas study for the OEB at the suggest of Union Gas consultant Dr. Melvyn Fuss, a University of Toronto economics professor. In the recent Hydro One Distribution proceeding PEG took the time to consider the appropriate index to use going forward and determined that the implicit price index for the utility sector would be best for power distribution. We believe that it also makes sense for transmission. Attachment PEG-HOSSM-11e (c) provides an analogous comparison of the tracking power of the implicit price index for utility assets and the PSE index. It can be seen that the implicit price indexes do a better job, particularly during the years before 2000 when the EUCPIs still worked well.

f. To the best of PEG's knowledge, the rate of return on capital for Hydro One Networks' transmission operations was not available for the early years of the sample period.

INTERROGATORY #12

Reference: Exhibit M1, page 16

PEG states: "We expect the first variable to have a positive parameter and the second variable to have a negative parameter".

Please confirm that this is a mistake, since the second variable being referenced is the share of transmission plant to the utility's non-general gross plant value, and this variable has a positive sign in both PEG's and PSE's model.

Response to Hydro One SSM-12: The following response was provided by PEG.

This mistake is confirmed.

INTERROGATORY #13

Reference: Exhibit M1, page 15

On page 15 PEG discusses the ratcheted maximum demand variable.

a. What is the first year of the ratchet for the U.S. sample? In other words, how far back does the U.S. variable look to find the maximum demand for the U.S. utilities?

b. What is the first year of the ratchet for Hydro One's ratcheted maximum demand variable value?

c. Is the racheted maximum demand variable definition consistent between Hydro One and the U.S. sample?

Response to Hydro One SSM-13: The following response was provided by PEG.

a. The first year of the ratchet for the US demand data was 1995.

b. The first year of the ratchet for Hydro One's was 2002.

c. The general approach is consistent but the start dates for Hydro One and the U.S. companies were of necessity different.

INTERROGATORY #14

Reference: Exhibit M1, page 17 - Table 1

It appears that PEG used the same explanatory variables that PSE used in its model, except for: (i) the change in the data source for the ratcheted peak demand, (ii) that substation capacity is now divided by line miles rather than the number of substations and is set to the year 2010, (iii) a percent overhead plant in service variable is used in place of PSE's underground variable based on actual km of line, and (iv) the number of substations per km of line variable is excluded.

a. Are these the only four variable differences in variables relative to the PSE econometric model? If not, please describe any other differences.

b. Why is the substation capacity per line mile variable set to the 2010 value? Why not use PSE's more contemporary values for substation capacity that are calculated to 2016?

c. In examining PEG's working papers, it appears that the percent overhead variable used by PEG is now based on the percentage of overhead gross plant in service rather than on actual km of overhead lines. Please confirm.

d. If PEG's overhead variable is based on gross plant in service how did PEG determine a value for Hydro One for this variable? Please describe and provide an explanation on how this variable is defined in a consistent manner for Hydro One to the rest of the U.S. sample.

e. Why is PEG using a plant in service overhead variable rather than use the percent of actual transmission lines that are overhead?

f. In examining PEG's working papers, there appear to be five benchmarking observations in the 1990's that have a zero value for the percentage of transmission plant that is overhead.

   However, these utilities appear to have overhead lines. Please confirm these observations should equal zero.

g. In examining PEG's working papers, it appears that PEG modified the variable definition of the percent of transmission plant in total plant from what PSE used. Please confirm.

i. Please describe how did PEG make Hydro One's definition consistent with the U.S. sample?
ii. What variable value did PEG apply to Hydro One for this variable?

h. PSE's transmission substations per km of line variable and average voltage of transmission lines were calculated using actual data for the U.S. sample for the years 2013 to 2016. All years prior use the 2013 value. The 2013 variable value is 18 years after PEG's earliest sample year of 1995. At what point does PEG believe observations are too distant from calculated actual values to be meaningful? Is PEG concerned that these variable values could change over a span of 18 years?

i. Did PEG adjust for autocorrelation in the modeling procedure? Please describe the econometric modeling method used.

Response to Hydro One SSM-14: The following response was provided by PEG.

a. PEG confirms the differences listed. The only remaining difference is the transmission scope variable's definition. PEG does not include general plant in "total electric utility plant" in its calculation of percentage of transmission in total electric utility plant.

b. PEG confirms that this statement is true. They customarily calculate overhead and underground variables using plant value data. The variable should be broadly representative of the business condition (substation capacity per line mile) companies face over the entire sample period and hence ideally would be located near the middle of 1995-2016. Note however that PSE's values for substation capacity in years prior to 2013 are the 2013 value. The 2010 value is therefore just a placeholder for the earliest year available, 2013. There is no meaning behind the choice of 2010 in that regard.

c. Confirmed

d. PEG received data on percentage of plant value overhead from the company. The working papers show how this was plugged in.

e. PEG believes there are reporting problems in line characteristics and hence plant in service overhead variable is more accurate than the physical definition

f. These observations have been excluded from the analysis.

g. Confirmed.

h. PEG believes that substations per line km and the average voltage of transmission lines should be reasonably stable over time. That is why they used these ratio variables. Hydro One received a value of 1.

PEG implicitly assumes that this density variable is stable over time just as PSE does when it holds values constant where it did not have data.

i. Following PSE’s assumption that disturbances are heteroskedastic and contemporaneously correlated, PEG estimated the model with ordinary least squares and panel-corrected standard errors. No adjustment was made for serial autocorrelation in the errors.

INTERROGATORY #15

Reference: Exhibit M1, page 18

The report states that the trend variable parameter estimate is 0.29%. However, in Table 1 the trend variable is reported as 0.000 in the econometric model.

Please reconcile and explain which number is the correct one.

Response to Hydro One SSM-15: The following response was provided by PEG.

The correct value from Exhibit M1 is 0.03% in PEG's February report. The updated value as reported in the attachment to 6i (a) is -0.34%.

INTERROGATORY #16

Reference: Exhibit M1, page 19

PEG states that the effects of formula rates were less pronounced over the 1996 to 2016 sample period, relative to the 2005 to 2016 sample period.

a. How many sampled utilities were regulated using formula rates in 1996?
b. How many sampled utilities were regulated using formula rates in 2005?
c. How many sampled utilities were regulated using formula rates in 2016?

Response to Hydro One SSM-16: The following response was provided by PEG.

PEG counted a utility as having a formula rate plan if it was approved by the FERC as part of an open access transmission tariff ("OATT") and addressed the entirety of a transmitter's revenue requirement. As discussed in Appendix B3 to PEG's testimony, prior to the adoption of OATTs transmission services were typically bundled with wholesale generation and the rates for these services often varied between customers (e.g., some customers may have their rates set using formula rates while others did not). To avoid the possibility of counting a formula rate plan which was only approved on an interim basis and then subsequently rejected, PEG relied on the date of the final FERC approval order before counting a utility as being regulated using formula rates. This procedure produced the following results.

a. In 1996, zero sampled utilities were regulated using formula rates.
b. In 2005, 15 sampled utilities were regulated using formula rates.
c. In 2016, 42 sampled utilities were regulated using formula rates.

Thus, the use of formula rates grew markedly during the years of PSE's sample period. This likely affected cost growth and has no counterpart for Hydro One Networks during the years of its proposed IRM.

INTERROGATORY #17

Reference: Exhibit M1, page 19

PEG mentions productivity research commissioned by the Australian Energy Regulator.

a. Please provide the report being referenced.

b. What is the Australian Energy Regulator's finding for the Australian industry transmission MFP trend in the referenced report?

c. What is the sample period used by the Australian Energy Regulator in the referenced report?

Response to Hydro One SSM-17: The following response was provided by PEG.

a. The report is Attachment PEG-HOSSM 17a.

b. The AER's consultant reports a -1.34% average annual growth rate in the MFP of Australian power transmitters. However, its consultant employed a physical asset rather than a monetary approach to measuring capital quantities. This disregards the effect of depreciation on cost growth. The most recently released report by AER's consultant showed a broad-based uptick in productivity with substantial growth in multifactor productivity and both partial factor productivity measures. Output increased by nearly 5% while input declined, resulting in MFP growth between 2016 and 2017 of nearly 6%, while operation expense and capital partial factor productivity trends of between 5.5 and 6%.

   Both the Australian Energy Regulator and Energy Networks Australia, the utilities' trade association, issued press releases about the uptick in productivity, with Energy Networks Association stating that this was the biggest transmission productivity increase in "the measure's recorded history." The press release of the Australian Energy Regulator can be found at this link: https://www.aer.gov.au/news-release/improving-productivity-helps-consumer-hip-pocket, while Energy Networks Australia's press release can be found at this link:

   https://www.energynetworks.com.au/sites/default/files/11302018_productivity_benchmark_final.pdf

   The sample period used in the latest study is 2006-2017.

INTERROGATORY #18

Reference: Exhibit M1, page 20 – Table 2

Regarding Table 2 on page 20 of the PEG report:

a. Please explain how the 2005 to 2016 MFP trend is reported at -1.82%, but all the productivity components of MFP are higher within the table.
b. Please explain how the 1996 to 2016 capital quantity index trend is 1.13%, but the two components of capital (Transmission capital and Allocated General Plant) are each higher.
c. Please explain how the 2005 to 2016 Summary Input Quantity index growth of 2.54% is higher than all the component trends.
d. Please provide PEG's explanation for the U.S. industry's MFP results being negative by more than (in absolute terms) 2% from 2013 to 2016. Please include in your comments if PEG believes the addition of more renewables onto the transmission grid may be contributing to these results.

Response to Hydro One SSM-18: The following response was provided by PEG.

a. TFP growth can thought of as a weighted average of the PFP growth rates. The same can be said for the summary input quantity index and the summary capital quantity index. The relative importance of subindexes such as O&M in determining the input quantity summary index will vary by company. Observations with low weighting but atypical values will have a greater impact on the calculation of the more detailed average than on the calculation of the summary average. In addition, each annual growth rate was calculated as a cost-weighted average of the annual growth rates for individual companies. Changes in company weighting vs. that for other companies over time can also cause the averages to not show the intuitive property.

b. Please see the response to part a.

c. Please see the response to part a.

d. PEG has not examined the reasons for substantially negative productivity growth from 2013 to 2016. Reviewing Table 2 of PEG's report suggests that growth in transmission capital quantities was the main driver of the decline in MFP during this period. The Edison Electric Institute recently issued a policy brief on the need for transmission investment. The policy brief identified replacement investments and the need to connect new renewable generation to the grid as

drivers of increased capex.
http://www.eei.org/issuesandpolicy/transmission/Documents/ROE%20Issues%20Broad%20Infrastructure%20Investment%202-pager.pdf

INTERROGATORY #19

Reference: Exhibit M1, page 21 – Table 3

Regarding Table 3 on page 21 in the PEG report:

a. Please confirm that the industry output quantity index is twice as rapid as that of Hydro One during the 2005 to 2016 period.

b. PEG's 1996 to 2016 industry output quantity index grows by 0.91% per year. Hydro One's projected output quantity index for 2019 to 2022 is 0.00%. Would PEG expect a slower growing utility (slower in terms of the output quantity index) to have slower MFP growth?

c. Please confirm that Hydro One's OM&A cost definition used in calculating Hydro One's productivity is not the same cost definition as used for the U.S. sample.

d. Please confirm that Hydro One's input price inflation assumptions come from different indexes from those used for the U.S. sample.

Response to Hydro One SSM-19: The following response was provided by PEG.

a. PEG confirms that this statement is true.

b. PEG believes that slower output growth will tend to slow MFP growth by diminishing the opportunities for the realization of scale economies. However, scale economies are only one of several productivity growth drivers.

c. PEG confirms that it used different definitions of OM&A expenses for Hydro One and the sampled US utilities.

d. PEG confirms that it used different input price indexes for Hydro One and the sampled U.S. utilities. Its goal in so doing was to increase the accuracy of its study.

INTERROGATORY #20

Reference: Exhibit M1, page 22 – Table 4

a. In comparing PEG Table 2, Table 3, and Table 4, it appears that Hydro One's productivity (MFP) is more rapid than the industry's MFP from 2005 to 2016 by over 0.60%. Yet Hydro One's benchmark score on Table 4 is declining during this same time period. Why does PEG find that Hydro One's productivity is growing more rapidly than the industry's productivity, but its benchmark score is getting worse over the same time period?

b. How did PEG decide to use a sample of 1995 to 2016 in the benchmarking sample?

c. If PEG was only concerned about benchmarking Hydro One's 2020, 2021, and 2022 total costs in the most accurate way possible, would PEG modify the sample period to include only more recent years? Please explain.

d. Is PEG excluding the same costs for Hydro One that it excludes for the U.S. sample for the projected years of 2020, 2021, and 2022? If not, please explain how this inconsistency does not invalidate PEG's results. If so, please provide the data source or method used to exclude those costs for Hydro One.

Response to Hydro One SSM-20: The following response was provided by PEG.

a. In comparison to MFP indexes, the econometric model can account for the effect on cost of changing business conditions and has a more sophisticated translog treatment of the effect on cost of changing output growth. The trend parameter in PEG's econometric model reflects business conditions over the full sample period and not just the 2005-2016 period when, as we have seen, the Energy Policy Act of 2005 was instituted and many utilities commenced operations under formula rate plans. This can result in different trends in cost performance relative to productivity growth.

b. This was the longest period for which all the required data were available electronically from the FERC website.

c. No. The goal in estimating an econometric benchmarking model is to get the best estimates of the parameters. The longer sample period is generally better for this purpose, and there are special advantages to not using a period during which the Energy Policy Act and the adoption of formula rate plans slowed cost growth.

d. No. PEG did not believe the cost associated with these items would have a material impact on the conclusions and did not have the data to do such an adjustment. They invite Hydro One to provide the data and/or adjust the cost levels and results that remove these costs.

INTERROGATORY #21

Reference: Exhibit M1, page 41

PEG describes their incentive power model as "a mathematical optimization model."

a. Could the results be characterized as a hypothetical construct of what would happen if all the model assumptions are met?

b. The model assumes no inflation from year-to-year, correct? Does PEG include input price inflation in its MFP and cost benchmarking research found in the PEG Report?

c. On p. 41 PEG states that "Capital accounts for a little more than half of this cost." Does this match with the capital cost shares found in PEG's U.S. transmission productivity sample?

d. On p. 41 PEG states that: "The annual depreciation rate is 5%, the weighted cost of capital is 7%, and the income tax rate is 30%." Does the depreciation rate of 5% match with what PEG assumed in the transmission productivity research? Does the weighted cost of capital of 7% match with what PEG used in the transmission productivity research? Does the income tax rate of 30% match with the actual experience of the transmission sample and for Hydro One?

Response to Hydro One SSM-21: The following response was provided by PEG.

a. Yes. However, PEG believes that results are suggestive of what would happen under alternative model assumptions. Model assumptions were chosen for their reasonableness. Utilities helped to fund PEG's incentive power model and have benefitted from it insofar as it suggests that modest stretch factors are warranted in typical IRMs. Results of PEG's incentive power model were recently published in a white paper for Lawrence Berkeley National Lab.

b. The model does specify no inflation. This simplified the analysis with little if any diminution in the relevance of the model's results. Consideration of inflation is, on the other hand, unavoidable in the statistical analysis of cost.

c. PEG acknowledges that the capital cost share is typically higher in the transmission industry.

d. These assumptions are modestly at variance with the those that are applicable to contemporary power transmitters. PEG and PSE both excluded taxes from their studies.

INTERROGATORY #22

Reference: Exhibit M1, page 41

PEG states: *The company is assumed to have opportunities to reduce its cost of service through cost reduction effort. Two kinds of cost reduction are available. Projects of the first type lead to temporary (specifically, one year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for sustained reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years, and five years, respectively.*

a. PEG says this hypothetical utility starts with base rate inputs of $500 million. At the 30% inefficiency level, what is the dollar amount for the cost saving opportunities for the first type of temporary cost reductions? At the 30% inefficiency level, what is the dollar amount for the cost saving opportunities for the payback period of one year cost reductions? Three year? Five year? Please break this down for OM&A and capital assumed cost saving opportunities.

b. Given that the size of Hydro One's revenue requirement is considerably larger than the $500 million of the hypothetical utility (let's assume 4 times larger), would it be appropriate to multiply the cost saving opportunities PEG is assuming in the hypothetical utility by four to determine what PEG's assumption is for the cost saving opportunities available to Hydro One?

Response to Hydro One SSM-22: The following response was provided by PEG.

a. The answers to these questions are not readily available, as this study was done several years ago by a colleague who no longer works at PEG. After leaving PEG, Travis Johnson earned a PhD at the Stanford University business school and is now a professor at the University of Texas business school.

b. PEG does not believe that the smaller size of the assumed utility reduces the pertinence of the results for Hydro One since the focus of the study is on the productivity effects of different regulatory systems.

INTERROGATORY #23

Reference: Exhibit M1, page. 42

PEG mentions "employee distress" costs of undertaking cost containment projects. These are assumed to occur up front. However, when taking a net present value calculation, this will amplify the costs of undertaking an action relative to the costs being incurred when the cost savings are assumed to occur.

a. Please re-run the incentive power model that spreads these "employee distress" costs to when the costs are being reduced. How does this impact the results?

b. On what basis does PEG assume that the "employee distress" costs equal about one quarter of the size of the accountable upfront costs?

c. Why would reducing future capital spending create employee distress at such a high level?

Response to Hydro One SSM-23: The following response was provided by PEG.

a. This run is not possible given the time and budget available. The individual who developed this model no longer works for PEG.

b. PEG believes that this is a reasonable assumption based on its years of experience in the field Distress costs are one reason why the weaker performance incentives of utilities weaken their performance.

c. Reducing future capital spending can place pressure on work crews to build facilities more efficiently and pressure management to develop innovative means to avoid capex. It can also risk the alienation of vendors and trigger undiscoverable declines in the quality of work.

INTERROGATORY #24

Reference: Exhibit M1, page 42

PEG states: *The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings in a given year, less the distress costs of performance improvement, given the regulatory system, the income tax rate, and the available cost reduction opportunities.*

a. Does the incentive power model account for the fact there is a degree of regulatory oversight in costs being prudent and reasonable in the US?

b. Does the incentive power model assume there is no concern for ratepayers by utility management in determining if cost containment investments should be made?

c. Does the incentive power model assume there is no concern by utility management that its regulators may determine it is an inefficient utility and negatively impact its financial performance?

d. Does the incentive power model assume the utility will never undergo a Management Audit or have its expenses scrutinized by the regulator through another manner?

Response to Hydro One SSM-24: The following response was provided by PEG.

a. No. However, PEG believes that commission oversight of everyday cost management for utilities is largely ineffective. Cost disallowances are generally rare except for high profile problems.

b. Yes. But many years of consulting assignments in the utility industry does not suggest to PEG that the welfare of customers is a major consideration of utility employees in managing costs. They are concerned about service quality and safety, and these concerns raise cost.

c. Please see the response to part a of this question.

d. Yes.

INTERROGATORY #25

Reference: Exhibit M1, pages 46, 47, 48 – Tables B1, B2, B3

Does PEG equate formula rate plans with what PEG terms "cost plus" regulation in PEG's incentive power model and Tables B1, B2, and B3?

Please explain any differences between the two. Please address in the response if the transmission formula rates typically are based on costs in the prior year or if the rate adjustments and the costs associated with those adjustments are in the same time period.

Response to Hydro One SSM-25: The following response was provided by PEG.

Yes, for FERC-approved formula rate plans. An alternative approach would be to take the 0.33% average of the incentive power productivity trends for cost plus regulation and two-year plans. This would not greatly change the results of PEG's analysis.

Formula rate plans do provide a limited opportunity for interested parties to review cost. For example, the formula rate protocols for Northern States Power specify that the Company is required to present its projected revenue requirement by September 1st. Parties then have until December 1st to file information requests on the Company's proposals. These information requests allow parties an opportunity to review the accuracy and appropriateness of the proposed revenue requirement, including prudence and the impact of accounting changes. The parties then have another 60 days to inform Northern States Power of any specific informal challenges to the revenue requirements and until April 15th to file formal challenges to the proposed revenue requirement. Unless a party makes a formal challenge, the FERC is generally not involved in the formula rate process and only if a formal challenge is made does Northern States Power bear the burden of proof that its filing is appropriate. The approved revenue requirement is subsequently trued up with interest once actual data become available. PEG understands that some formula rate plans set rates on the basis of historical costs.

INTERROGATORY #26

Reference: Exhibit M1, page 45

PEG states: "*Inspecting the results for the reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under true cost plus regulation.*"

Does PEG believe that all utilities under formula rate plans have never undertaken cost reduction initiatives while on a formula based plan?

Response to Hydro One SSM-26: The following response was provided by PEG.

No. However, the incentive power model does shed light on the reduced cost efficiency incentives generated by formula rates.

INTERROGATORY #27

Reference: Exhibit M1, page 46 – Table B1

On PEG's Table B1, the NPV of cost reductions if the plan term equals six years is $1.428 billion.

Is it the proper interpretation of this figure that a utility with $500 million in revenue requirement would be able to identify and then make cost savings of $1.428 billion in NPV terms? If this is not the proper interpretation, please explain what the proper interpretation is.

Response to Hydro One SSM-27: The following response was provided by PEG.

The incentive power model calculates savings over an 85-year time frame. The idea is that the NPV of cost reductions in a *lengthy sequence* of plans of this type could be quite substantial.

INTERROGATORY #28

Reference: Exhibit M1, page 49

PEG states: "*The explicit stretch factor for a utility of average efficiency should thus lie in the [0.50 – 1.01] range if the U.S. MFP trend from 2005-16 provides the basis for the base productivity trend in Hydro One's SSM's revenue cap index.*"

a. This [0.50 – 1.01] stretch factor estimate assumes that formula rates are equivalent to cost plus regulation, transmission OM&A is close to 50% of costs, and that cost containment initiatives would never be undertaken by utilities under formula rates. Is this correct? If not, please explain.

    i. What is the average cost share of OM&A for the industry in PEG's productivity study?

b. Is it PEG's contention that if a utility proposes a regulatory structure with higher incentive properties that its stretch factor should be increased? If so, explain how this would impact the incentives to put forth plans that have strong incentives.

Response to Hydro One SSM-28: The following response was provided by PEG.

a. PEG acknowledges that the OM&A cost share of transmission utilities is typically well below 50%. However, it is not clear why this assumption materially compromises the incentive power research results.

b. Yes. This is a key part of the rationale for stretch factors in IRMs and is part of the reason why a higher stretch factor makes sense for utilities that are operating under the Annual IR Index. A higher stretch factor can weaken the incentives for utilities to put forth plans with stronger incentives but need not eliminate the incentives if the stretch factor is reasonable. In any event, IRM initiatives are often spearheaded by regulators and other policymakers rather than utilities.