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BY COURIER

February 26, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

EB-2018-0218 – Hydro One Sault Ste Marie ("HOSSM") – Written Interrogatory Questions Regarding Expert Evidence Filed by OEB Staff

In accordance with Procedural Order No. 4, please find attached Hydro One Sault Ste Marie's ("HOSSM") interrogatories regarding the expert evidence filed by OEB staff with respect to HOSSM's application for its 2019 transmission revenue requirement.

An electronic copy of these questions has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JEFFREY SMITH

Jeffrey Smith

<u>Hydro One Sault Ste. Marie Interrogatories</u>

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.

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 productivity expectations for Hydro One over the Custom IR term (2019-2022)?

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.

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.

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.

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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.

<u>INTERROGATORY #6</u>

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.

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?

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?

INTERROGATORY #9

Reference: Exhibit M1, page 12

PEG 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.

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?

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?

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.

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?

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.

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.

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?

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?

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.

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.

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.

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?

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?

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?

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?

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.

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?

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.

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.