Board Staff/PEG Responses to
Toronto Hydro-Electric System Limited (“THESL”) Interrogatories
Custom Incentive Rate-Setting Application for 2015 to 2019
Electricity Distribution Rates and Charges
EB-2014-0116
January 16, 2015

Note: All references to “the PEG Report” or “PEG’s Report” in these interrogatories correspond to the December 8, 2014 Report entitled “*Toronto Hydro Electric System Limited Custom IR Application and PSE Report Econometric Benchmarking of Toronto Hydro’s Historical and Projected Total Cost and Reliability Levels*,” as updated by way of the OEB Staff letter of December 17, 2014.

1-THESL-1.

Please confirm that the cost performance scores on page 1 of the PEG Report are calculated by taking the percentage difference between the predicted total costs and the actual total costs.

Confirmed.

1-THESL-2.

(a) Did PEG conduct any other statistical tests that would reveal the causes of THESL's higher or lower total cost performance besides testing the null hypothesis that the utility's costs were different than the benchmark level?

No

(b) If yes, please provide the results of the tests and the underlying calculations.

Not applicable.

1-THESL-3.

Please state whether a 10-year old pole would add more or less to PSE's measure of capital costs compared with a two-year old pole, assuming the original costs for the pole were the same?

> All else equal, a 10-year old pole would "add more" to PSE's measured capital costs over the 10 years that pole has been in service than a two-year old pole would add to PSE's measured capital costs over the two years it has been in service.

1-THESL-4.

Reference: PEG Report, p.7, paragraph 1: "PSE and PEG agree that THESL's SAIFI is far greater than what is expected for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer. Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% may even be appropriate for THESL."

a) Please confirm that THESL's cost performance, as evaluated by PEG, is statistically inferior only for the forecasted time period, but statistically average during the historic 2010-2012 time period.

Confirmed. Like PSE and THESL, PEG's recommended stretch factor is linked to THESL's cost evaluation for the forecast, custom IR period rather than THESL's historic cost evaluation for the 2010-2012 period.

b) Please confirm that PEG's statements regarding THESL's reliability levels are based on the historic period of 2009-2011 only and not on projected data during the Custom IR period.

Confirmed. In response to Undertaking No. J2.11, THESL indicated that its SAIFI and SAIDI projections "do not rely on a specific mathematical model" but are instead based on "an in-depth analysis" of: 1) the existing state of Toronto Hydro assets; 2) the historical reliability performance of the system; and 3) the expected effects of the planned programs on the future state of the system.

PEG does not believe that THESL's purported "in-depth analysis" is sufficient for generating objective SAIFI and SAIDI projections. PEG believes the bases for the specific values of THESL's projected SAIFI and SAIDI must be explicitly articulated, well-understood, and tested to ensure that they are objective and replicable before they are given any weight by the Board. If THESL's SAIFI and SAIDI projections are not objective and verifiable, the Company's projected SAIFI and SAIDI *performance* will also not be objective. SAIFI and SAIDI projections must be derived objectively, or THESL will be able to "choose" whatever projected reliability performance it likes by selecting arbitrary and/or subjective values for future SAIFI and SAIDI. To the best of PEG's knowledge, the bases of THESL's SAIFI and SAIDI projections have not been subject to rigorous review by PSE or any other third party.

1-THESL-5.

Reference: PEG Report, p. 12, paragraph 2: "*PSE's conclusion that 'the company's capital was in need of investment' is simply speculation; this conclusion does not follow logically or empirically from the benchmarking studies presented.*"

Please provide a citation from the PSE Report, which includes the entire context of the statement where PSE concluded that "the company's capital was in need of investment".

The entire context for the referenced statement comes from page 33 of the PSE report and is replicated below:

"The following table breaks down the historical and forecast year benchmark and company total costs from 2002 to 2014 and then during the Custom IR period of 2015 to 2019. During the historical period Toronto Hydro has been consistently below its expected benchmark levels. In the second column, the percent below benchmark is illustrated. Notice that prior to 2007 the company was consistently near 30% below benchmark expectations. This is suggestive that the company's capital was in need of investment."

Page 12 of the PEG report says "PSE's conclusion that 'the company's capital was in need of investment' is simply speculation; this conclusion does not follow logically or empirically from the benchmarking studies presented." The Merriam-Webster online dictionary defines "conclusion" as 'a reasoned judgment: inference.' PEG believes the context presented above shows that it is PSE's "reasoned judgment" or "inference" that "the company's capital was in need of investment." Since a conclusion is a reasoned judgment or inference, it follows that "PSE's conclusion (is) that 'the company's capital was in need of investment.'"

1-THESL-6.

Reference: PEG Report, p.3, paragraph 2.

a) Please define how PEG is using the term “cost management”.

   In this paragraph, “cost management” is the management of capital expenditures.

b) Please state whether in PEG’s view, a utility’s cost management, as defined by PEG in part (a), may affect its reliability indexes?

   Yes

   i. If yes, how?

      See Chapter Five of the PEG Report.

   ii. If no, why not?

1-THESL-7.

Please state whether in PEG's view, a lower overall total cost performance can have a negative impact on a company's reliability indexes?

> PEG interprets the reference to "a lower overall total cost performance" as equivalent to "improved cost performance," *i.e.* a larger (negative) gap between a distributor's actual costs and its predicted costs. Provided a utility is not inefficiently deferring necessary capital expenditures, PEG does not believe improved cost performance will have a "negative impact" on a distributor's reliability indexes.

1-THESL-8.

Reference: PEG Report, p. 14, paragraph "…PSE finds THESL's SAIFI to be reasonable because it is declining under Custom IR, even though SAIFI exceeds its benchmark level in every year of the plan."

Please provide a citation from the PSE Report, including the entire context, where PSE states that it "finds THESL's SAIFI to be reasonable because it is declining under Custom IR".

> On page 11 of the PSE Report, the final two sentences of bullet point 5 read as follows:
>
> "The SAIFI projections, assuming full funding, move the company towards the benchmark SAIFI value, reducing the number of outages experienced by customers. Thus, the company's plan to increase capital spending to address SAIFI is, in our opinion, reasonable from a benchmarking perspective."
>
> In the first sentence, the "SAIFI projections" refer to THESL's projected SAIFI under Custom IR. These projections "move" SAIFI "towards the benchmark SAIFI value" by "reducing the number of outages experienced by customers." A "move" in SAIFI which reduces "the number of outages experienced" is synonymous with a decline in SAIFI. The first sentence therefore says declines in SAIFI are projected under Custom IR, "assuming full funding" of the Company's proposal to increase capital spending under the Custom IR plan.
>
> The second sentence begins with "thus," which is a synonym for "therefore." This sentence thereby establishes an explicit, logical link between the preceding sentence, which said THESL's SAIFI is projected to decline if the company's capital spending plan is fully funded, and the words that follow, which are: "the company's plan to increase capital spending to address SAIFI is, in our opinion, reasonable from a benchmarking perspective."
>
> The PSE Report therefore explicitly links the conclusion that "the company's plan to increase capital spending to address SAIFI is…reasonable" to the declines in SAIFI that are projected to result under Custom IR from THESL's increased capital spending.

1-THESL-9.

Reference: PEG Report, p.17, paragraph 5: "Figure Two illustrates why 'converging towards benchmark expectations' is not a reasonable regulatory objective

Please specify the basis for PEG's conclusion that converging towards THESL's SAIFI benchmark expectation is not a reasonable regulatory objective?

> The preamble refers to the statement in the PSE Report that "spending forecasts will converge the company's SAIFI *and total costs* towards the benchmark expectations" (italics added). Pages 15 through 20 of the PEG Report provide an extensive, and illustrated, discussion of the basis for PEG's conclusion that this is not a reasonable regulatory objective because: 1) if current performance exceeds benchmark expectations, converging to the benchmark implies a degradation in performance; and 2) encouraging continuous performance improvements is a Board objective.

1-THESL-10.

Please state whether the capital costs per Kilometer of undergrounding power lines are constant for all utilities, or whether they would vary based on service territory conditions such as terrain or urbanization?

> The capital costs per km of undergrounding power lines will vary depending on a utility’s business conditions.

1-THESL-11.

a) Please provide a price (or price range) for typical construction costs of one kilometer of direct buried underground cable line in a rural, agricultural area.

b) Please provide a price (or price range) for typical construction costs of one kilometer of underground line using encased concrete conduit in a highly urban area.

c) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a rural, agricultural area.

d) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a suburban area?

e) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a highly urban area?

a) PEG cannot provide a specific price, or price range, for this particular investment, but we can provide general quantitative information on the relationship between the population density of urban areas and construction costs.

PEG examined US Census Bureau data on population and land area (in square miles) for US population centers. These data were drawn from the *Patterns of Metropolitan and Micropolitan Population Change: 2000 to 2010*, CBSA Report Chapter 3 (CBSA=core based statistical area) at **http://www.census.gov/population/metro/data/pop_data.html.**

Using these Census Bureau data, PEG computed population density (*i.e.* area population divided by land area in square miles) for all identified metropolitan areas in the 48 states of the continental US. We determined the top ten and bottom ten metropolitan areas in the continental US in terms of population density.

PEG then obtained RS Means data on electric utility construction cost indices for each utility in the top ten and bottom ten groups, in terms of population density. We computed a population-weighted RS means construction cost index for the top ten US areas in terms of density, and a population-weighted RS Means construction cost index for the bottom ten US areas in terms of density. Comparing these two averages provides a measure of the relative differences in more-urban versus less-urban/more-rural electric utility construction costs in the US. PEG excluded Alaska and Hawaii from this analysis because their distance and isolation from other US population centers makes them special cases with respect to a variety of input and output price comparisons.

This analysis is presented in Exhibit THESL-11. It can be seen that the ten most densely-populated metropolitan areas are: 1) New York City; 2) Los Angeles CA; 3) San Francisco CA; 4) Trenton-Ewing NJ; 5) Bridgeport-Stamford CT; 6) New Haven CT; 7) Chicago IL; 8) Boston MA; 9) Philadelphia PA; and 10) Tampa FL. The ten least densely-populated metropolitan areas (beginning with the least densely populated) are: 1) Flagstaff AZ; 2) Casper WY; 3) Lake Havasu AZ; 4) Rapid City SD; 5) Wenatchee WA; 6) Farmington NM; 7) Prescott AZ; 8) Grand Forks ND; 9) Great Falls MT; and 10) Bismarck, ND.

The populated-weighted average for the most densely populated US areas is 118.9. The populated-weighted average for the least densely populated US areas is 84.8. This indicates that construction costs are, on average, approximately 40.2% higher in the most urbanized parts of the US compared with the least-urbanized areas (*i.e.* 118.9/84.8 = 1.402).

This analysis is indicative only, and it does not control for differences in assets that may be installed to serve the most densely-populated areas compared with less-densely populated territories. Nevertheless, PEG believes this is strong evidence that there is a positive correlation between electric utility construction prices and the degree of urbanization throughout the US.

Moreover, it should be noted that PEG's benchmarking model controls for the higher costs of electric utility construction in urban areas. Construction cost price differences are reflected directly in the capital service price measures PEG developed for each US utility, and for THESL. Each utility's capital service price is included as an independent variable in PEG's cost benchmarking model. PEG's model therefore controls directly for differences in construction costs across service territories – and for relative differences in more-urban versus less-urban construction costs – in our econometric benchmarking model and in the econometric cost evaluations for THESL and the US sample.

b) Please see the response to part a).

c) Please see the response to part a).

d) Please see the response to part a).

e) Please see the response to part a).

1-THESL-12.

Please provide PEG's views on installation/construction cost comparisons for the following asset categories:

a) Which is likely to cost more: installing 1 kilometer of direct buried cable in a rural area, or installing 1 kilometer of the equivalent cable in a highly urban area?

The answer depends on other business conditions in the rural and "highly urban" areas. For example, if the rural area is quite remote and/or characterized by difficult terrain, it can be more expensive to install underground cable in a rural area than in a highly urban area.

b) Please rank the following three asset categories from most to least expensive:

i. installing 1 km of overhead line in a rural area;

ii. installing 1 kilometer of equivalent overhead line in a suburban area; or

iii. installing 1 km of equivalent overhead line in a highly urban area?

The response to part a) of this interrogatory applies to overhead as well as underground assets: the relative costs of installing overhead line in rural versus "highly urban" areas depends on other business conditions in the rural and highly urban territories. It is typically least expensive to install overhead line in suburban areas.

1-THESL-13.

Does PEG believe the costs of undergrounding one Kilometer of line is typically the same as rural areas as it is for highly urban areas? If yes, why? If no, why not?

No. Please see the response to THESL Interrogatory numbers 10, 11, and 12.

1-THESL-14.

a) Please provide all natural gas distribution benchmarking reports prepared by PEG in the last 10 years that contain urban density variables in their analysis.

Please see the attached studies in THESL Exhibit-14. All three of these studies contain urban core variables, not "urban density variables" *per se*. It should be noted that the attached study for San Diego Gas and Electric includes separate econometric cost models for gas distribution and for electricity distribution. Only PEG's gas distribution cost model for SDG&E includes the urban core dummy variable; the electricity distribution cost model does not.

b) Has PEG performed any electric or natural gas distribution benchmarking in the last ten years that includes a variable to distinguish between the costs of rural and urban distribution? If so, please provide copies of the resulting reports.

Yes. Please see the response to part a).

1-THESL-15.

Please provide in Excel format the underlying data and calculations for the variable "MVA of transformer capacity for stations with primary voltage levels at or above 50 kV" used in PEG's Report.

> PEG has provided three files in response to this interrogatory. The first is a comma-separated (CSV) text file containing the station data. Given the size of this file, some of the calculations and data manipulations involved in constructing the MVA transformer capacity variable are unwieldy and difficult in Excel. PEG has therefore provided the requested data in a comma-separated text file.
>
> The second is PEG's map file, which maps utilities' FERC ID numbers to PEG ID numbers. The third file is the script necessary to calculate total MVA capacity for stations with primary voltage levels at or above 50 kV, as well as total MVA capacity. All files are attached as Exhibit THESL-15.

1-THESL-16.

Has PEG included a first-order variable in an econometric total cost model that had a p-value of 0.4 or above in any testimony filed in the past ten years? If yes, please provide the study reports.

Yes. The trend variable in a cost function is a “first order variable,” and Table Three of the PEG Report includes a trend variable with a p-value of 0.4180. PEG also includes variables that are not ‘first order’ variables in econometric models when they have p-values of 0.4 or above if it is important for the model to include those variables. For example, PEG has included quadratic (*i.e.* squared) and interaction terms for input price and output variables with p-values of 0.4 or higher because it is important to include those variables in a translog cost function.

Table Three of the PEG Report also includes a variable measuring each distributor’s MVA of transformer capacity with primary voltage equal to or greater than 50 kV, and it has a p-value of 0.6522. We believe it is critical to include this variable and report this result in Table Three for two reasons: 1) the importance of the high-voltage transformation issue in Ontario benchmarking; and 2) to make “apples to apples” benchmarking comparisons between THESL and US utilities. Please see the response to THESL Interrogatory 17 for additional information.

1-THESL-17.

In light of the changes to the sign, coefficient and p-value of the MVA of Transformer Capacity variable in the updated PEG Report, as communicated by way of the OEB Staff letter from December 17, 2014, does PEG believe that it needs to update its argumentation and/or conclusions as to the appropriateness of using this variable in PEG's model?

No. Controlling for differences in high-voltage transformation assets among distributors was an important part of PEG's cost benchmarking work in 4^{th} Gen IR. Distributors and stakeholders recommended that the costs used to benchmark Ontario distributors not be distorted by differences in the ownership of high-voltage transformer stations. The most straightforward and effective means of minimizing this distortion was removing all RRR capital and operating costs assigned to high voltage assets from the costs subject to benchmarking. Eliminating these costs led to downward adjustments in the costs to be benchmarked for a number of Ontario distributors, including THESL.

Many utilities in PSE's US sample own high-voltage transformation. The costs of high-voltage transformation assets are included in PSE's total cost measures for these utilities. Because the US utilities' costs include the costs of high-voltage transformation while THESL's benchmarked costs do not, there is an inconsistency in the cost measures used to benchmark THESL and the US sample. All else equal, this inconsistency will "improve" THESL's measured cost performance, because the sample used to generate predicted costs for the Company includes cost components that are absent from THESL's actual measured costs. However, this "improvement" in THESL's measured performance results from the fact that many US utilities are effectively providing (and incurring the costs of providing) more services than THESL. Benchmarking analysis should control for differences in distribution services across utilities rather than allowing them to be inappropriately reflected in measured cost performance.

The PSE Report did not acknowledge these adjustments of THESL's costs or take any efforts to control for differences in high-voltage transformation between THESL and the US sample. While it is important to control for these differences, it is not possible to standardize US and THESL costs directly because the US FERC Form One does not separately account for the capital and operating costs of high-voltage transformation assets. PEG therefore could not apply the same cost adjustments to US utilities that we applied to THESL and the Ontario distributors.

The next-best solution is adding an independent variable to the cost model that reflects the extent of high-voltage transformation services provided by utilities. In principle, the estimated coefficient on such a variable reflects the additional costs a utility incurs when it undertakes a greater amount of high-voltage transformation. The MVA capacity of stations with primary voltage levels at or above 50 kV is a measure of a utility's capacity to provide high-voltage transformation, and data on this variable can be obtained from the FERC Form One. PEG therefore added this variable to our cost model to control for differences in the costs of owning high-voltage transformation across the sample.

While physical asset measures like MVA of transformer capacity can in principle reflect high-voltage transformation costs, such metrics also have practical limitations. One obvious problem is that physical asset measures do not reflect asset depreciation. Differences in the "vintage" of transformer capacity will impact the net asset values for transformer stations that factor into the capital costs computed by PSE (and PEG), but the MVA capacity measure will not reflect these cost differences. This limitation, and others, reduce the ability of the MVA of transformer capacity to control effectively for differences in the costs of high-voltage ownership across the US-THESL sample.

This point can be illustrated by considering a simple example. Suppose utility A has twice as much reported MVA of high-voltage transformer capacity as utility B, but utility A's assets are much older, and depreciation has reduced the gross value of high-voltage transformation assets by 60% for utility A but by only 10% for utility B. In this example, net transformer plant would actually be lower for utility A than utility B even though utility A has twice as much physical transformer capacity as utility B. All else equal, the coefficient on the MVA variable in this example would have a negative sign since the utility with higher MVA capacity will have lower measured costs. This is the opposite of the expected positive coefficient on the MVA variable.

Physical capacity measures therefore control for differences in ownership of high voltage transformer stations less effectively than the cost adjustments PEG employed in Ontario, but they are the best available option for US-THESL benchmarking. Moreover, PEG believes it is critical to include MVA of high-voltage transformation as an independent variable in a US-THESL cost benchmarking model for two reasons. One is the importance of controlling for differences in high-voltage ownership in previous Ontario benchmarking studies. The second is THESL's measured performance will be distorted if no controls are made to reflect differences in high-voltage transformation.

In PEG's original report, the coefficient on the MVA variable was near zero but slightly positive. The estimate was not statistically significant. After this report was filed, PEG noticed minor errors in the MVA capacity data used for some sample utilities. We corrected these data and re-ran the "Revised Data and Model" econometric cost model. The coefficient on the MVA variable in this updated model was still near zero but slightly negative. The estimate was again not statistically significant.

PEG used the corrected, updated model to benchmark THESL's cost performance in 2010-2012 and during the Custom IR period. Compared with the results presented in the PEG Report, this change reduced the positive difference between THESL's actual and predicted cost declined by between 1% and 2%, depending on the year being benchmarked. These small changes did not impact PEG's conclusions regarding the statistical significance of THESL's cost performance in 2010-2012 or its projected cost performance during Custom IR.

The changes in the sign, coefficient and p-value of the MVA of transformer capacity variable communicated in the December 17, 2014 Staff letter are therefore quantitatively minimal and substantively immaterial. Moreover, for the reasons described above, PEG believes it is critical for a model benchmarking THESL against US utilities to include a measure of MVA of transformer capacity as an independent variable, even though this variable has limitations that can make it difficult to reflect and control for the costs associated with high-voltage ownership. PEG accordingly included the MVA variable in the "final" PEG model and reported the results, regardless of the statistical significance of the estimated MVA coefficient.

1-THESL-18.

The high voltage variable added by PEG into THESL's total cost benchmarking calculation has a p-value of 0.6522. Please provide a plain language explanation of what this number means relative to the null hypothesis that its true value is zero.

> A p-value of 0.6522 means the null hypothesis that the parameter value is equal to zero cannot be rejected.

1-THESL-19.

For PSE’s original U.S. sample of 85 utilities, please list the utilities that have fully deployed smart meters (fully deployed defined by at least 95% of a utility’s customers having a smart meter) by the end of the sample period in 2012.

> PEG cannot verify how many of the 85 U.S. utilities will have fully deployed smart meters by the end of the sample period in 2012.

1-THESL-20.

a) Please confirm that the U.S utilities in PSE's sample include contributions in aid of construction (CIAC) in their FERC Form 1 data reporting.

   Not confirmed. The U.S. utilities in PSE's sample do not include CIAC in their FERC Form 1 reporting.

b) If PEG provides confirmation in its answer to part (a), please indicate which FERC account number the CIAC is this placed in and provide documentation showing that CIAC meets the definition for inclusion in the indicated FERC account

   Not applicable.

c) Please calculate and provide in Excel format the costs attributed to THESL's CIAC contributions that PEG added to the utility's total cost calculation for years 2002 through 2019.

   PEG did not *add* the costs of CIAC to THESL's cost measure; PEG *subtracted* the costs of CIAC from THESL's costs to be benchmarked. Please see page 25 of the PEG Report.

1-THESL-21.

Please calculate and provide in Excel format the costs attributed to smart meter expenses added to THESL's total cost definition by PEG for the years 2002 through 2019.

> Please see the attached working papers from IRM-4. PEG did not "add" smart meter expenses to THESL's total cost definition but instead used the benchmarking-based cost definition to benchmark THESL and all other Ontario distributors in 4^{th}GenIR. PEG did not explicitly add any smart meter expenses to THESL costs for the years 2013-2019 but instead adjusted the Company's 2012 costs using THESL's projected annual change in costs for these years, as reported by PSE. Please see the response to THESL Interrogatory 23 for details.

1-THESL-22.

Please calculate and provide in Excel format any other cost additions PEG made to THESL's total cost definition for the years 2002 through 2019.

PEG did not make any cost *additions* to THESL's cost definitions; we made several *subtractions* from THESL's benchmarked cost and similar subtractions from the US utility cost data so that the US costs would be defined comparably to THESL's. Please see pp. 23-25 of the PEG Report and responses to THESL Interrogatories 20, 23, and 24.

Our measure of THESL costs also excluded the costs of owning high-voltage transformation; these costs were included for the US sample and could not be eliminated directly because of the lack of necessary data, but PEG did attempt to control for this difference in cost definitions by including the MVA variable in step three of our work. Please see pp. 27-28 of the PEG Report and the response to THESL Interrogatory 17.

1-THESL-23.

In its Report, PEG states that it subtracted the amounts related to uncollectible accounts from the U.S. data to make it comparable to the Ontario data (which excluded bad debt expenses).

a) While performing these adjustments, did PEG also subtract the bad debt expenses included in the forecasted THESL data for the years 2013 through 2019? If not, why not?

PEG's estimates of THESL projected costs in 2013 -2019 do "subtract" bad debt expenses for the Company, although this is done implicitly rather than explicitly because PEG was not provided data on THESL's projected bad debt expenses after 2012. PEG calculated THESL's projected costs for 2013 -2019 by taking our estimated 2012 cost for THESL (which excludes bad debt expenses) and adjusting it by the annual percentage change in PSE's "Actual Cost THESL, $M" reported in Table 6 (and Table 9) of the PSE Report. This calculation was done for each year between 2013 and 2019.

PEG believes this approach actually *understates* THESL's costs net of bad debt expenses in 2013 – 2019. The PEG approach implicitly assumes bad debt expenses will increase at the same rate as all other costs reflected in PSE's measure of "actual costs" for THESL over the 2013 – 2019 period. If this assumption is true, PEG's measure of THESL costs which eliminates bad debt expenses will necessarily grow at the same rate in the 2013-2019 period as THESL's overall actual costs developed by PSE, and PEG's projected costs for THESL net of bad debt expenses will be accurate.

However, given THESL's planned capital expenditures program, and the fact that capital will be increasing as a share of THESL's overall costs between 2013 and 2019, it is likely that THESL's capital costs are growing *more rapidly* than bad debt expenses. The presence of bad debt expenses in PSE's reported "Actual Cost THESL" is therefore likely to slow the growth rate of PSE's cost measure compared to the growth of a cost measure (like PEG's) that eliminates bad debt expenses. Thus, if PEG had data on the growth of THESL's actual costs in 2013-2019 net of bad debt expenses, it would likely be growing *more rapidly* in 2013-2019 than the growth rates PEG actually applied in those years to our 2012 measure of THESL costs.

This implies that PEG's analysis understates THESL costs (net of bad debt expenses) for 2013-2019. If we had more precise data on THESL's cost components in 2013-2019, the Company's actual costs would likely have been higher in those years. THESL's cost performance would, in turn, be worse than the results presented in Table Four of the PEG Report.

PEG has therefore subtracted an estimate of bad debt expenses from THESL costs in 2013-2019 using a conservative methodological approach that is likely to understate the positive difference between THESL's projected and predicted costs, and thereby over-state THESL's cost performance, in the 2013 – 2019 period.

b) Please confirm whether the uncollectible amount costs subtracted from the U.S. utilities' total cost definitions include only the amounts associated with uncollected revenues themselves, and not the operating costs of arrears management and collection activities.

Confirmed.

1-THESL-24.

In its Report, PEG states that it subtracted all of the customer service and information expenses from the U.S. data to adjust for the fact that the Ontario data excluded CDM expenses.

a) Did PEG also subtract all of the corresponding customer service and information expenses not related to CDM from both the historical and/or the forecasted THESL cost data in its analysis? If not, why not?

Yes; please see the response to THESL Interrogatory 23 a).

b) Is PEG concerned that excluding the entire customer service and information expense category for the U.S. utilities might eliminate the data that corresponds to cost components included in THESL's total cost calculation, thus making the data for the US sample not comparable to THESL?

No.

c) Why did PEG not simply add THESL's CDM expenses into the total cost definition, rather than excluding the entirety of the customer service and information expenses for 85 U.S. utilities?

PEG did not add THESL's CDM expenses to its total cost definition because THESL's CDM expenses will be recovered during the Custom IR period through the global adjustment mechanism and not included in distribution rates, which are the focus of the benchmarking exercise.

d) On page 25 of its Report, PEG states that it excluded customer service and information expenses "(for which CDM often constitutes the largest expense)." Please provide the data and any documentation to support the claim that the CDM costs often constitute the largest expense item in the customer service expenses and information expenses category.

The Customer Service and Information expenses include FERC Accounts 907, 908, 909 and 910. The documentation below is FERC's description for what is to be included in, and allocated to, each of these accounts. The account descriptions include numerous references to encouraging the "safe, efficient, and economical use of the utility's service," which is another way of describing CDM activities.

907 Supervision (Major only).

This account shall include the cost of labor and expenses incurred in the general direction and supervision of customer service activities, the object of which is to encourage safe, efficient and economical use of the utility's service. Direct supervision of a specific activity within customer service and informational expense classification shall be charged to the account wherein the costs of such activity are included. (See operating expense instruction 1.)

908 Customer assistance expenses (Major only).

This account shall include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service.

ITEMS

Labor:

1. Direct supervision of department.

2. Processing customer inquiries relating to the proper use of electric equipment, the replacement of such equipment and information related to such equipment.

3. Advice directed to customers as to how they may achieve the most efficient and safest use of electric equipment.

4. Demonstrations, exhibits, lectures, and other programs designed to instruct customers in the safe, economical or efficient use of electric service, and/or oriented toward conservation of energy.

5. Engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service.

Materials and Expenses:

6. Supplies and expenses pertaining to demonstrations, exhibits, lectures, and other programs.

7. Loss in value on equipment and appliances used for customer assistance programs.

8. Office supplies and expenses.

9. Transportation, meals, and incidental expenses.

NOTE: Do not include in this account expenses that are provided for elsewhere, such as accounts 416, Costs and Expenses of Merchandising, Jobbing and Contract Work, 587, Customer Installations Expenses, and 912, Demonstrating and Selling Expenses.

909 Informational and instructional advertising expenses (Major only).

This account shall include the cost of labor, materials used and expenses incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

Labor:

1. Direct supervision of informational activities.

2. Preparing informational materials for newspapers, periodicals, billboards, etc., and preparing and conducting informational motion pictures, radio and television programs.

3. Preparing informational booklets, bulletins, etc., used in direct mailings.

4. Preparing informational window and other displays.

5. Employing agencies, selecting media and conducting negotiations in connection with the placement and subject matter of information programs.

Materials and Expenses:

6. Use of newspapers, periodicals, billboards, radio, etc., for informational purposes.

7. Postage on direct mailings to customers exclusive of postage related to billings.

8. Printing of informational booklets, dodgers, bulletins, etc.

9. Supplies and expenses in preparing informational materials by the utility.

10. Office supplies and expenses.

NOTE A: Exclude from this account and charge to account 930.2, Miscellaneous General Expenses, the cost of publication of stockholder reports, dividend notices, bond redemption notices, financial statements, and other notices of a general corporate character. Exclude also all expenses of a promotional, institutional, goodwill or political nature, which are includible in such accounts as 913, Advertising Expenses, 930.1, General Advertising Expenses, and 426.4, Expenditures for Certain Civic, Political and Related Activities.

NOTE B: Entries relating to informational advertising included in this account shall contain or refer to supporting documents which identify the specific advertising message. If references are used, copies of the advertising message shall be readily available.

910 Miscellaneous customer service and informational expenses (Major only).

This account shall include the cost of labor, materials used and expenses incurred in connection with customer service and informational activities which are not includible in other customer information expense accounts.

Labor:

1. General clerical and stenographic work not assigned to specific customer service and informational programs.

2. Miscellaneous labor.

Materials and Expenses:

3. Communication service.

4. Printing, postage and office supplies expenses.

e) Please provide an Excel table showing the percent of CDM expenses in customer service and information expenses for each U.S. utility included in the PSE study sample for years 2002 through 2012 inclusively.

This information cannot be provided because the FERC Form One does not establish separate, explicit accounts for CDM expenses. However, PEG has provided an Excel file that includes the requested data for FERC Accounts 907-910. This file is attached as Exhibit THESL-24.

f) Please provide the full names and definitions of eligible cost items for all FERC accounts and sub-accounts classified collectively as Customer Service and Informational Expenses.

Please see the response to part d).

g) Please provide documentation showing that U.S. utilities should record, or routinely do record, CDM (DSM) expenses in the customer service and information cost category on FERC Form 1.

Please see the response to part d).

1-THESL-25.

In its Report, PEG eliminated seven utilities from PSE's original dataset due to the fact that these utilities have undergone mergers during the 2002-2012 period, which, in PEG's contention, can impact the utilities' cost data if not properly controlled for the impact of mergers.

a) Did PEG undertake a statistical analysis showing how mergers impacted the 2002-2012 cost data for the excluded utilities? If yes, please provide the data, results, and calculations in Excel format.

PEG did not undertake any specific statistical analyses, but some utility data displayed anomalous changes in (or immediately after) the merger year.

b) *Reference: PEG Report, p.23, paragraph 3: "Mergers can impact a utility's reported cost data."* Please confirm that all of the excluded merged companies have their cost data impacted by the mergers. If not all merged companies had their costs data impacted by mergers, please list the companies whose data was so impacted.

Please see the response to THESL Interrogatory 25a).

c) Please provide the data and calculations used for each merger that enabled PEG to determine that the merger impacted the utility's reported cost data.

Please see the response to THESL Interrogatory 25a).

d) PSE notes that PEG's report did not include the list of U.S. utilities used in the final sample. Please list the utilities that PEG excluded on the basis they underwent a merger during the 2002-2012 time period. Please also provide the list of the utilities included in the final sample used to formulate Table Three on p. 32 of the PEG Report.

The following companies were excluded because they had a merger or divestiture from 2002-2012. Green Mountain Power, Ohio Power, Georgia Power, Public Service of New Mexico, Sierra Pacific Power, Southwestern Electric Power, Southwestern Public Service, and Potomac Edison. Please see Exhibit THESL-25 for a full list of companies in the sample.

e) Has Dr. Kaufmann or PEG used in any previous study the utilities excluded from PSE's sample on the basis of having undergone mergers in 2002-2012? If so, please provide copies of those reports or testimony.

Yes. Several the mergers or divestitures mentioned in part d) had not taken place over the time period covered by many earlier PEG studies, which obviously eliminates the need to exclude them. In some cases where a merger had taken place, it was possible to reconstruct the data for the current merged company by aggregating the pre-merger historical data for the utilities that merged. Companies for which PEG was not able to correct for mergers in this manner were excluded. Please see the studies attached in Exhibit THESL-25 for the last five years.

1-THESL-26.

Reference: PEG Report, p. 23, paragraph 5: "Appropriately controlling for mergers is often critical for obtaining accurate inferences on utilities' cost performance".

a) Please discuss PEG's understanding of an appropriate way of controlling for utility mergers.

The most appropriate way to control for mergers is to aggregate the historical data of the utilities being merged (*i.e.* those utilities' data prior the merger) so that those historical data are comparable to the post-merger data reported by the merged utility.

b) Did PEG include any business condition variables specific to mergers in its Ontario econometric total cost model for the 4th Generation IR study?

No. There was no need to include such a business condition variable in PEG's cost benchmarking model in 4th Gen IR, because Board Staff have developed data series for merged distributors in Ontario that aggregate the historical data for the utilities that merged. This is an example of "the most appropriate way to control for mergers" described in part a) of this Interrogatory response. Those data were provided by Board Staff to PEG and used in our benchmarking work. PEG's 4th Gen IR benchmarking therefore controlled for mergers in Ontario during the 2002-2012 sample period, in contrast to PSE's US sample for the same period, which failed to control for mergers. If the data used in 4th Gen IR benchmarking had not controlled for mergers in the Province during the sample period, PEG's benchmarking study would not have been credible.

c) Please list all Ontario utilities that underwent mergers during the 2002-2012 period?

Please see the attached Exhibit THESL-26 which shows the relationship between current and historical Ontario LDCs.

1-THESL-27.

<u>Reference: PEG Report, p. 31, paragraph 1. PEG states that "approximately 67.4% of the share of transformer stations for U.S. utilities takes place at a primary voltage level of 50 kVA or above".</u>

a) Please state whether 50 kVA is equivalent to 50 kV

Yes, it is.

b) Please provide in Excel format the underlying data and calculations that enabled PEG to calculate the 67.4% number.

Please see the response to THESL Interrogatory 15.

1-THESL-28.

a) Please explain PEG's methodology for calculating the MVA capacity of substations with primary voltage of 50 kVA for THESL.

The request should reference substations with a primary voltage of 50 kV, not 50kVA; please see the response to THESL Interrogatory 27a). A database of all distribution substations for sampled US utilities was assembled. Those substations listed as having a primary voltage of 50 kV or greater were extracted. The listed MVA capacity of these substations in a given year was then aggregated for each sampled utility.

b) Are all of the station costs for THESL excluded in the total cost definition if the primary voltage exceeds 50 kVA?

Yes; all of the capital and OM&A station costs explicitly allocated to the RRR high voltage cost components have been excluded from THESL's total cost definition.

1-THESL-29.

a) Please confirm that all of the substations PEG used in its “greater than 50 kVA” variable construction are classified as Distribution Substations.

Confirmed.

b) Please provide the details for stations comprising the “greater than 50 kVA” variable for each utility in the sample, including the functional classification of distribution or transmission, and the substations included in the variable calculation.

Please see the response to THESL Interrogatory 28a).

1-THESL-30.

a) Please state whether the urban core variable as constructed and utilized in PSE's U.S. total cost econometric benchmarking model, was statistically significant in that model.

Yes.

b) What was the p-value associated with the variable?

The p-value for the urban core variable is not presented in the PSE Report, but the estimate of the parameter is statistically significant at the 1% level.

c) Please re-run and provide results for PEG's total cost model shown on Table Three of the PEG Report with the exact same variables, but with PSE's urban core variable included.

PEG disagrees in principle with PSE's "urban core" dummy variable for reasons that are discussed on pp. 28-31 of the PEG Report. In response to THESL Interrogatory 43, PEG also explains why PSE's urban core variable cannot provide an accurate and credible estimate of the impact of urbanization on distribution costs in the US electricity distribution industry. The reason is PSE has identified only four "urban core" utilities and ignored at least 23 other utilities in its sample that also serve an urban core/central business district at the center of a large urban area. Some of the 23 utilities PSE did not designate as "urban core" companies serve a more urbanized territory than half of PSE's selected urban core utilities. Please see the response to THESL Interrogatory 43 for details.

PEG has therefore provided two sets of empirical results in response to this interrogatory. The first adds PSE's, four-utility urban core dummy variable to the cost model shown in Table Three of the PEG Report and re-runs the model. The results of this "four utility urban core dummy variable" model are presented in Table 30.1. The second adds an all-inclusive urban core dummy variable to the model shown in Table Three of the PEG Report, in which dummy variables are included for PSE's four "urban core" utilities plus the 23 other utilities in PSE's US sample that serve an urban core (as identified in the response to THESL Interrogatory 43). The results of this "all urban utilities" model are presented in Table 30.2.

Table 30.1

Econometric Cost Benchmarking Results:

Corrected THESL Results Plus Four-Utility Urban Core Dummy

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
CAP= MVa of Capacity with Primary Voltage >= 50kV
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
ED= Elevation Standard Deviation
PF= Percent Forestation
UD= City Population Above 1M
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7008	388.717	0.0000
N*	0.6026	20.920	0.0000
D*	0.2584	8.486	0.0000
KxK*	0.1161	18.745	0.0000
NxN*	0.5385	5.718	0.0000
DxD*	0.4605	4.730	0.0000
KxN*	0.0533	4.782	0.0000
KxD*	0.0449	4.020	0.0001
NxD*	-0.4956	-5.470	0.0000
CAP	0.0019	0.826	0.4090
PRV*	0.0294	2.056	0.0401
PCE*	0.1068	3.471	0.0005
PDE*	0.1467	8.178	0.0000
ED	0.0064	0.878	0.3802
PF*	0.0118	2.156	0.0314
UD*	0.0092	2.980	0.0030
Trend	0.0033	2.504	0.0125
Constant*	13.0285	845.832	0.0000
System Rbar-Squared	0.941		
Sample Period	2002-2012		
Number of Observations	805		

***Variable is significant at 95% confidence level**

Table 30.2

Econometric Cost Benchmarking Results:
Corrected THESL Results Plus
All Urban Utilities Variable

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
CAP= MVa of Capacity with Primary Voltage >= 50kV
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
ED= Elevation Standard Deviation
PF= Percent Forestation
UD= Industry Urban Core Dummy
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7027	388.494	0.0000
N*	0.6690	21.858	0.0000
D*	0.2145	6.859	0.0000
KxK*	0.1125	18.185	0.0000
NxN*	0.6919	7.139	0.0000
DxD*	0.5953	5.702	0.0000
KxN*	0.0433	3.875	0.0001
KxD*	0.0522	4.674	0.0000
NxD*	-0.6345	-6.619	0.0000
CAP	-0.0020	-0.877	0.3809
PRV*	0.0356	2.449	0.0146
PCE*	0.1308	4.321	0.0000
PDE*	0.1302	7.052	0.0000
ED*	0.0172	2.362	0.0184
PF*	0.0130	2.393	0.0169
UD	-0.0063	-0.930	0.3525
Trend	0.0008	0.564	0.5732
Constant*	13.0368	667.064	0.0000
System Rbar-Squared	0.942		
Sample Period	2002-2012		
Number of Observations	805		

***Variable is significant at 95% confidence level**

d) Is the urban variable statistically significant at the 90% confidence level? At the 95% confidence level?

PSE's four-utility urban core dummy variable is statistically significant at the 90% and 95% confidence levels. However, the dummy variable that is applied to all urban utilities in PSE's US sample is not statistically significant at the 90% or 95% confidence levels.

PEG still disagrees in principle with using "urban core" dummy variables in electric utility benchmarking for reasons that are discussed in the PEG Report. However, PEG believes the results presented in Tables 30.1 and 30.2 support the conclusion that PSE's four-utility urban core dummy variable only quantifies company-specific factors (potentially including management efficiency) at the four selected utilities rather than measuring the impact of urbanization on costs in the US electric utility distribution industry. A broader and more inclusive urban core measure, applied to utilities serving 27 urban areas throughout the US, indicates that there is no statistically significant relationship between an urban core dummy variable and US electricity distribution costs.

1-THESL-31.

Please confirm that PEG’s model in Table Three includes neither a percent undergrounding nor an urban core variable.

Confirmed.

1-THESL-32.

Reference: PEG Report, p. 29, paragraph 1: "Since PSE's model already includes a percent of plant underground variable, including an 'urban core dummy' would be redundant at best."

Please confirm that PEG has excluded both the Urban Core and the Undergrounding variables from the model's final run. Please provide the rationale for excluding both variables.

> Confirmed. The rationale for excluding the urban core dummy was explained on pp. 28-31 of the PEG Report. The undergrounding variable was excluded because it was either statistically insignificant or had the wrong (negative) sign.

1-THESL-33.

a) Does the final PEG model (Table Three) control for the cost impacts of undergrounding? If yes, please explain.

The "final" benchmarking model presented in the PEG Report did not identify an independent, statistically significant impact of undergrounding on electricity distribution cost. This is consistent with the PEG benchmarking model the Board is currently using to assign stretch factors for Ontario electricity distributors. This PEG model also did not identify a statistically significant impact of undergrounding on Ontario distributors' total costs, although PEG econometric models developed earlier in the 4th Gen IR proceeding did find greater undergrounding was associated with higher electricity distribution costs in Ontario. This finding was no longer true after the final, more carefully defined cost measures for Ontario distributors were developed in consultation with industry and stakeholders during the course of the 4th Gen IR proceeding.

In PEG's opinion, the lack of an undergrounding variable in "the final PEG model" represents a substantial improvement on the "US only" benchmarking model presented in the PSE Report. PSE's US only benchmarking model found that greater undergrounding of assets *reduced* electricity distribution costs for THESL and the US electric utility sample. PEG believes PSE's result is counter-intuitive and implausible, and counter-intuitive and implausible benchmarking models do not appropriately "control for the cost impacts of undergrounding."

b) Does the final PEG model (Table Three) control for the added costs of serving urban environments? If yes, please explain.

Yes. Four variables in "the final PEG model," presented in Table Three of the PEG Report, control for the added costs of serving urban environments: 1) N x N; 2) D x D; 3) K x N; and 4) K x D.

In the cross section of investor-owned US utilities in PEG's (and PSE's) samples, there is a positive relationship between the overall size of a utility and its urban-ness. In other words, the largest utilities in PEG's and PSE's samples also tend to be the ones that serve large urban areas. This relationship is not surprising, because large urban areas clearly contain large numbers of electricity distribution customers and high levels of peak demand. Customer numbers and demands in large population centers will be reflected in the size of the US electricity distributors serving those urban areas.

There are two output measures in PEG's and PSE's econometric models: number of retail customers (N) and peak demand (D). Higher values of N and D measure increasing levels of customers and peak demand, respectively. The N x N and D x D variables represent the *squared* values of customer numbers and peak demand, respectively. These terms are standard in the translog functional form used by both PEG and PSE. For firms serving large numbers of customers and peak demand, the square terms N x N and D x D naturally increase at a more rapid rate than the N and D terms. All else equal, this implies that the coefficients on the squared N x N and D x D terms reflect the costs associated with the largest - and most urban – utilities in the US plus THESL sample, relative to the average firm in this sample. The coefficients on these terms therefore reflect and control for the impact of serving more urban territories in the US plus THESL sample.

This relationship can perhaps be clarified by considering a relatively simple numerical example. Consider two utilities, A and B, in two periods, 1 and 2. Utility A serves 100,000 customers in period 1 and utility B serves 1,000,000 customers in period 1. Between periods 1 and 2, assume customers grow by 1% for each utility.

For utility A, the 1% growth in customers corresponds to an increase in 1,000 customers (*i.e.* 100,000 * .01 = 1,000). For utility B, the 1% growth in customers corresponds to an increase of 10,000 customers (*i.e.* 1,000,000 * .01 = 10,000). A 1% growth rate for both A and B therefore leads to 10 times as many customers being added for utility B as for utility A. This is intuitive because utility B had 10 times as many customers as utility B in period 1. The same percentage increase in customer numbers for utilities A and B therefore leads to 10 times as many customers added for utility B as for utility A.

Now consider how the squared term, N x N, compares for utilities A and B in this same example. In period 1, the N x N term is equal to 10^{10} for utility A (*i.e.* $100{,}000^2 = (10^5)^2 = 10^{10}$) and 10^{12} for utility B (*i.e.* $1{,}000{,}000^2 = (10^6)^2 = 10^{12}$). In period 2, the N x N term will equal $1.0201 * 10^{10}$ for utility A (*i.e.* $101{,}000^2 = 1.0201 * 10^{10}$). The N x N term in period 2 equals $1.0201 * 10^{12}$ for utility B (*i.e.* $1{,}010{,}000^2 = 1.021 * 10^{12}$).

Using these figures, it is easy to show that between periods 1 and 2, customers squared increased by 201,000,000 for utility A and by 20,100,000,000 for utility B. The change in customers squared for utility B is therefore 100 times greater than the change in customers squared for utility A (*i.e.* 20,100,000,000/201,000,000 = 100), even though both customers experienced 1% growth in customer numbers between periods 1 and 2.

This example shows that, for the squared N x N term, a 1% growth rate in customers does not lead to the same, proportional change in customer additions for utility A and utility B between the two periods. A 1% increase in customers leads to 100 times more change in measured (squared) output for utility B as it does for utility A even though utility B is only 10 times as large as utility A in period 1.

The squared output term N x N therefore tends to grow more rapidly over time for relatively large, and more urban, utilities in the US plus THESL sample. This in turn means the measured N x N variable is positively related to the size and urban-ness of distributors in the US plus THESL panel dataset (*i.e.* a dataset that includes both cross-sectional and time series data). All else equal, the coefficient on the N x N term therefore reflects the costs associated with serving larger and more urban territories within the sample, compared with smaller and less urban territories. Analogous logic applies to the D x D square term. All else equal, the coefficient on this term also reflects the costs associated with serving larger and more urban territories in the US plus THESL sample.

The coefficients on K x N and K x D also reflect urban characteristics. The K variable measures each distributor's capital service price in a year. A utility with higher values of K x N means the utility *simultaneously* faces a higher capital service price and serves a larger number of retail customers, compared with the average firm in the US plus THESL sample. With PEG's (and PSE's) capital service price measure, one utility will have higher than average capital service prices only when measured construction prices for that utility exceed sample average construction prices.

The prices for construction labor tend to be higher in urban territories. There is accordingly a positive relationship between the capital service price K and serving an urban territory. Please see the information provided in response to THESL Interrogatory 11 for further details.

As discussed, in the US plus THESL sample, there is also a positive relationship between output levels N and D and serving an urban territory. Thus, when a utility's construction prices/capital service prices and output are *both* greater than the sample mean, this is a strong indicator that the utility is serving an urban area. All else equal, the terms K x N and K x D therefore reflect the costs associated with serving larger and more urban territories in the US plus THESL sample.

Thus, four variables in the final PEG model will reflect and control for the costs of urban environments: 1) N x N; 2) D x D; 3) K x N; and 4) K x D. Table Three in the PEG Report shows that our estimated coefficients for all four of these variables are positive. Each variable is also highly significant statistically (at a greater than 1% significance level). The positive, highly significant estimates on all four of these variables are all evidence of a positive relationship between electricity distribution costs for the US-THESL sample and the extent to which a utility serves an urban area. The presence of these four variables in "the final PEG model" accordingly reflects and controls for serving urban territories.

Interestingly, the PSE model also estimates positive coefficients on its N x N and D x D variables, although the magnitudes of these coefficients are lower than in PEG's model, and the variables are not as significant statistically. In PSE's US Only model, the coefficients on N x N and D x D are 0.270 and 0.141 respectively. In Table Three of the PEG report, the coefficients on N x N and D x D are 0.6856 and 0.5932, respectively. The K x N and KxD variables are not significant in the PSE model.

c) Does the final PEG model (Table Three) control for the added costs of serving less dense rural environments? If yes, please explain.

Yes. All else equal, percent forestation will be positively correlated with less dense and more rural territories, so the PEG model does reflect and control for the costs of serving more rural environments.

1-THESL-34.

Reference: PEG Report, p. 31, paragraph 3: "The third and final step of PEG's updated analysis therefore reflects corrections to the THESL and US data, as well as changes in business conditions to control for US utilities' costs of owning HV transformation assets and to eliminate the urban core dummy."

a) Was the percent underground variable also eliminated in this third and final step? If so, please provide the reference in the PEG report where it states that this variable was eliminated from PSE's model.

   Yes. The PEG Report did not explicitly reference that this variable was eliminated, but our standard practice is not to include business condition variables in reported econometric results when they are not statistically significant. An exception was made for the MVA of high voltage transformer capacity, for reasons that explained in the response to THESL Interrogatory 17.

b) Did PEG make any other changes in the model that are not clearly noted in the PEG report?

   No.

1-THESL-35.

a) Is a variable for customer density included in PEG's final model found in Table Three?

No.

b) If not, is PEG concerned that with no customer density variable, no urban variable, and no percent underground variable, PEG's model does not properly distinguish utilities serving rural, suburban, or urban environments?

No. Please see the response to THESL Interrogatory 33.

1-THESL-36.

Reference: Appendix to PSE Benchmarking study (Exhibit 2B, Tab 2, Schedule 2, Appendix B).

a) Does PEG agree or disagree with PSE's findings laid out in its engineering study submitted as an Appendix to its benchmarking report, which shows the different costs of serving environments with different customer densities (rural, suburban, urban)?

Dr. Kaufmann has reviewed and considered PSE's engineering report. However, because Dr. Kaufmann is not an engineering expert, he does not have an opinion on the technical merits of PSE's engineering analysis.

b) Please provide a detailed explanation for your answer to part a.

Not applicable.

1-THESL-37.

a) Has PEG produced a total cost econometric model for electric distribution anytime in the past ten years that included a customer density variable, line length, or percent undergrounding variable?

Yes.

b) If the answer to part (a) is yes, please explain why PEG included such a variable or variables and provide the report(s).

Customer density, line length, and undergrounding are all potentially significant cost drivers for electricity distributors.

1-THESL-38.

a) Does PEG's Ontario model developed for 4th Generation IR have variables for either customer density, line length, or percent undergrounding?

Yes. PEG's final econometric model in 4th Generation IR included line length as an independent variable, and earlier versions of PEG econometric models in 4th Generation IR included undergrounding as an independent variable. In those earlier benchmarking models, the undergrounding variable had the expected positive coefficient, not an anomalous negative coefficient as in PSE's study.

b) If the answer to part (a) is yes, please explain why PEG chose to include such a variable or variables.

Please see the response to THESL Interrogatory 37 b).

1-THESL-39.

Reference: PEG Report, p. 30, paragraph 2: "In July 2013, WPS was allowed to increase rates by approximately 4.36% to recover the costs of the SMRP."

a) In the footnote 17 for the above-reference passage, PEG notes that the 4.36% increase was for the bundled rates. What was the rate increase on just the distribution portion of WPS's request?

The rate increase was not disaggregated into different functions or applied only to distribution services, so this question cannot be answered.

b) Was the WPS rate request referenced by PEG on page 30 primarily driven by WPS increasing capital spending to improve reliability?

Yes.

c) Did Dr. Kaufmann testify in this case?

Yes.

d) If yes, by which party was he retained?

Dr. Kaufmann was retained by the Foley & Lardner law firm, on behalf of Wisconsin Public Service (WPS).

e) Please provide Dr. Kaufmann's testimony and transcripts in this case.

The documents for Dr. Kaufmann's Rebuttal testimony and Exhibit, Sur-surrebutal testimony and exhibit, and transcript are attached as Exhibits THESL-39.1, THESL-39.2, THESL-39.3, THESL-39.4, and THESL-39.5, respectively.

f) In the WPS rate case referred to by PEG on page 30, did Dr. Kaufmann find the increased rates were in the interests of customers? If yes, on what basis?

Not applicable. Dr. Kaufmann addressed the costs and benefits of the program itself and did not examine the rate changes for WPS customers. Dr. Kaufmann assessed program benefits by developing estimates of the value of reliability improvements that were expected to result from the System Modernization and Reliability Project (SMRP).

1-THESL-40.

a) Please provide all of the analysis and calculations used to derive Dr. Kaufmann's results in the WPS rate case referred to by PEG on page 30 of its Report.

Please see the response to Interrogatory 39 e).

b) In this WPS case, did WPS request increased capital funding for a five-year period?

Yes.

c) Was this added funding primarily for the purpose of improving the utility's reliability?

Yes.

d) Did WPS gain approval for the 5-year SMRP? Please describe the outcome of the case.

Yes. See p. 30 and footnote 17 of the PEG Report.

1-THESL-41.

a) In his oral or written testimony in the above-referenced WPS case, did Dr. Kaufmann ever suggest in written testimony that WPS could improve reliability without increasing costs?

    This was not the purpose of Dr. Kaufmann's testimony, so his testimony did not offer any "suggestions" on this issue.

b) Did Dr. Kaufmann ever suggest in the case that customers would be better off if the 5-year period was instead changed to a longer time period?

    No. However, no party presented evidence showing that WPS had historically displayed bad reliability performance, or that WPS was projected to display bad cost performance under the plan being reviewed by the regulator (in WPS's case, the Wisconsin Public Service Commission). PEG's review of PSE's analysis supports both of these conclusions for THESL. In Dr. Kaufmann's opinion, these findings warrant greater scrutiny and oversight of THESL's cost and reliability outcomes under the Custom IR plan when compared to the SMRP proposed by WPS. Enhanced oversight and review is facilitated by stretching the capital spending program over an eight-year rather than five-year period, because the volume of information to be reviewed each year is likely to be greater if the entire program is concentrated in five years rather than spread out over eight years. An eight-year plan also enables the regulatory treatment and recovery of capital expenditures in years six through eight of the plan to be informed by the Board's assessment of THESL's observed cost and reliability outcomes under Custom IR.

1-THESL-42.

a) Based on WPS estimates in the case discussed in the previous question, how much would the SMRP raise WPS distribution rate base after the 5-year period was finished?

Mr. Fenrick testified on behalf of WPS that the SMRP would increase WPS's distribution capital costs by 43% (Fenrick Rebuttal Testimony, p. 4, lines 19-20). However, PEG is not aware of any "WPS estimates" (*i.e.* testimony by WPS employees or other witnesses) that support this estimate.

b) Was this increase seen as reasonable by PEG?

PEG cannot accept the 43% estimate from Mr. Fenrick since it is not aware of any independent testimony or evidence that supports this estimate, and because PSE refused to provide the workpapers from the WPS case that would allow PEG to verify the estimate. Moreover, Dr. Kaufmann did not evaluate the increase in the rate base *per se* but instead compared the projected cost of the SMRP with the expected change in value from the project in terms of improved SAIDI. Dr. Kaufmann found the expected change in value exceeded the projected change in cost.

1-THESL-43.

<u>Reference: PEG Report, p. 30, paragraph 1: "It so happens that, collectively, the four utilities selected as serving urban cores tend to be average to poor cost performers."</u>

How did PEG determine that these four utilities were average to poor cost performers as opposed to being four utilities that share a common business condition, a high degree of urbanization, that is raising each of their costs?

The four selected utilities obviously, and unambiguously, do not "share a common business condition" of serving an "urban core" since one of the four "urban core" utilities (Arizona Public Service, or APS) does not serve a sizeable part of the central business district of the one large urban center in its territory.

In addition, PSE's designated "urban core' utilities do not include companies in its US sample that serve central business districts that are more developed than that within the APS territory and are comparable, and sometimes more pronounced, than the "urban core" served by San Diego Gas and Electric (another of the four utilities PSE deems as serving an "urban core"). At a minimum, the other utilities in PSE's sample that include an urban core/central business district at the center of a large urban area include: 1) AmerenUE, 2) Baltimore Gas and Electric; 3) Carolina Power and Light; 4) Cincinnati Gas and Electric, 5) Cleveland Electric Illuminating, 6) Detroit Edison, 7) Duquesne Light, 8) Entergy New Orleans, 9) Florida Power and Light, 10) Florida Power, 11) Georgia Power, 12) Indianapolis Power and Light, 13) Kansas City Power and Light, 14) Nevada Power, 15) Niagara Mohawk Power; 16) Northern States Power, 17) Pacific Gas and Electric, 18) Portland General Electric, 19) Potomac Electric Power, 20) Public Service of Colorado, 21) Puget Sound Energy, 22) Tampa Electric, and 23) Wisconsin Electric Power. Other utilities in the PSE sample also have undeniably urban characteristics; for example, Southern California provides service to 4.9 million customers primarily located in the Los Angeles metropolitan area.

In fact, a significant share of the sample that PSE has **not** designated as being "urban core" utilities is *more urbanized* than half of the four companies PSE has identified as serving "urban cores." PSE's urban core dummy cannot credibly estimate the cost impact of "a common business condition, a high degree of urbanization" when that sampled business condition is arguably more prevalent outside of PSE's four designated "urban core" utilities than it is within that small group. While the PEG Report provides a detailed explanation of the various problems with PSE's "urban core" dummy variable, a simple examination of the utilities that PSE has chosen to exclude from its list "urban core" companies is sufficient for concluding that PSE’s urban core dummy does not accurately quantify the impact of urbanization on distribution costs in the US electricity distribution industry.

1-THESL-44.

Reference: PEG Report, p. 42, paragraphs 3-4.

PEG's discussion of and conclusions regarding THESL's reliability levels were based on the assessment of the historic 2009-2011 period only.

a) Please provide THESL's projected SAIDI performance for every year up to and including 2019 using PEG's model.

   This information was filed in confidence on the record and was provided to all parties who have signed the confidentiality agreement.

b) Please provide THESL's projected SAIFI performance for every year up to and including 2019 using PEG's model.

   This information was filed in confidence on the record and was provided to all parties who have signed the confidentiality agreement.

c) Do the SAIDI and SAIFI results referenced in subs (a) and (b) change any of PEG's conclusions on THESL's reliability performance and the appropriate stretch factor for the utility?

   No. Please see the response to THESL Interrogatory 66 for details.

d) Please provide the reliability performance scores for THESL in PEG's reliability models for the 2010-2012 period.

   This information was filed in confidence on the record and was provided to all parties who have signed the confidentiality agreement.

1-THESL-45.

PEG's reliability models presented in Chapter Five exclude the forestation variable that PSE included in their models.

a) Does PEG agree that the level of vegetation on a system will have an impact on a utility's reliability performance?

Yes, and vegetation is correlated with precipitation in a utility's territory, all else equal. Vegetation is also correlated with forestation, but the forested parts a utility's territory are often in areas where there are relatively few distribution customers. Customers in forested areas may experience a large number of interruptions, but the fact that these customers often represent a small share of a utility's customer base means their outage experience will have a relatively small impact on the *system* average interruption frequency index, compared with the reliability experienced by the larger share of customers outside the territory's forested areas. In contrast, precipitation is typically more uniform than forestation throughout a utility's service territory. Although forestation and precipitation are both plausible business conditions to consider when benchmarking reliability, these factors support using precipitation rather than forestation as a variable that can impact *system-wide* reliability indices. PEG therefore used precipitation rather than forestation in our SAIFI and SAIDI benchmarking models.

1-THESL-46.

PEG's reliability models presented in Chapter Five exclude the wind variable that PSE included in their models.

a) Does PEG agree that exposure to greater amounts of wind will have an impact on a utility's reliability indexes, all other things being equal?

Yes, although PEG believes wind is a relatively less important *independent* business condition, particularly when precipitation is included as a variable in reliability benchmarking models. PEG did not find that PSE's wind variable was significant when it was included in our SAIFI and SAIDI models.

1-THESL-47.

PSE understands that PEG chose to substitute the percent undergrounding variable for customer density in the reliability models. Does PEG disagree that customer density will have an impact on a utility's reliability indexes?

> PEG does not disagree that customer density can impact a utility's measured reliability.

1-THESL-48.

Reference, PEG Report, p. 43, paragraph 3. "PEG does not dispute this common-sense linkage…" Please define and describe the common-sense linkage that PEG does not dispute.

Please see the last sentence in paragraph 2 on page 43.

1-THESL-49.

In Chapter Five (“Simultaneous Cost and Reliability Benchmarking”), did PEG create a model of its own to present the results shown on Table Seven of PEG’s Report (p. 47), or did it use PSE’s model that was developed in a prior rate case for Wisconsin Public Service (“WPS”)?

> PEG used the PSE “SAIDI impact benchmark model” referenced in Chapter Five of the PEG Report.

1-THESL-50.

Please confirm that PEG used THESL's annual capital expenditure amounts when calculating the SAIDI impact estimates found in Table Seven of PEG's Report. (p.47)

Confirmed.

1-THESL-51.

a) Is it PEG's position that THESL's proposed custom IR plan is purely driven by reliability objectives?

No.

b) If so, how does PEG regard the other stated reasons for the proposed IR plan, such as safety?

PEG reviewed THESL's Custom IR application and considered the Company's other stated reasons for the proposed IR plan, including safety.

1-THESL-52.

a) Does PEG agree that on page 2 of Mr. Fenrick's sur-surrebuttal testimony in the WPS case dated May 6, 2013, Mr. Fenrick clarified that the model uses the change in "electric net distribution plant," and not annual capital expenditures, to calculate the SAIDI impact benchmark?

> No, it does not, because PSE has not provided this testimony for this case. In Board Staff Interrogatory 11b), PSE was asked to "provide a copy of *all* such analyses (report, dataset, computer programs, spreadsheets, and testimony) that evaluate the cost effectiveness of reliability projects that PSE has undertaken and/or testified in support of" (emphasis added). In response, PSE said it provided "a copy of *the* testimony in this case" (emphasis added), which was the April 23, 2013 Rebuttal Testimony of Mr. Fenrick. Because this was the only testimony PSE provided regarding its SAIDI impact benchmark model, this was the testimony PEG referenced when preparing Chapter Five of the PEG Report. PSE elected not to put any other documents or testimony on the record related to this case, and it also refused to provide the workpapers associated with the model. PEG therefore has no basis for verifying which capital measure PSE used in its analysis, or for disregarding the evidence that PSE has provided in this proceeding.

b) Please verify that the WPS testimony states that WPS' electric net distribution plant was estimated to increase by 43% by 2019.

> Not verified. Please see the response to THESL Interrogatory 42.

c) Did Dr. Kaufmann support the notion that this 43% increase in net distribution plant was in the interests of WPS customers because of the reliability benefits derived from the plan?

> Please see the response to THESL Interrogatory 42 b).

d) Please calculate the increase of THESL's net distribution plant from 2014 to 2019?

> Not applicable.

e) Assuming PEG agrees that PSE used net distribution plant as the basis for the reliability impact calculation, please revise Table Seven in the PEG report to correct for the differences between PEG's initial approach and the PSE approach.

> Not applicable.

f) Does the revised table change any of the PEG Report’s conclusions?

Not applicable.

1-THESL-53.

Please indicate how many individual data points used as inputs for the purposes of econometric research in support of the 4th Generation IRM initiative have been based on assumptions to account for missing or unreliable data.

> PEG interpolated or adjusted 34 observations used in our cost benchmarking model in 4thGenIR. This amounts to approximately 0.4% of the data points used in that model. PEG believes three points regarding the adjustments of erroneous or anomalous Ontario data are noteworthy.
>
> First, the bases for the data adjustments that PEG made are plainly articulated. Second, PEG presented the entire list of such adjustments in Table 7 in our 4th Gen IR reports, to enhance transparency and credibility of the data used in the study. Third, PEG was aware of and identified the sources of the original data in our 4th Gen IR reports. In contrast, PSE's discussion of its reliability data was vague and opaque, and PEG's review revealed that PSE often did not know the sources of the reliability data used in its reliability benchmarking studies.

1-THESL-54.

Please discuss PEG's understanding of the current OEB requirements for Ontario distributors with respect to their year-over-year reliability performance.

> With the introduction of the balanced scorecard, Ontario distributors are required to keep their SAIFI and SAIDI performance within their average SAIDI and SAIFI performance over the preceding five years.

1-THESL-55.

a) Please state whether PEG's recommendation of extending the term of Toronto Hydro's proposed capital plan through to 2022 has considered the impact of such an adjustment on the safety of Toronto Hydro's distribution plant, service quality and reliability performance as prescribed by various OEB instruments, and legislative responsibilities to the utility's customers, shareholder and other parties.

Yes. Other than applying a stretch factor to capital as well as OM&A expenditures, PEG has not recommended a reduction in THESL capital expenditures that could impact the achievement of any of the stated objectives. PEG also believes that extending the capital plan to eight years rather than concentrating it in five years will ultimately benefit customers and other stakeholders. Please see the responses to THESL Interrogatory 41b) and 57 for additional details.

b) Please provide PEG's rationale for choosing to extend Toronto Hydro's proposed capital spending over an eight-year term?

As discussed on p. 56 of the PEG Report, the general rationale was that PEG believed "there would be value in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization, while at the same time managing the pace of rate increases for customers." The RRFE Report links the concepts of "pacing" and "prioritization" of capital spending to consideration of the total bill impact on customers. Please see the response to THESL Interrogatory 57 for further details.

Regarding the eight-year term in particular, this recommendation was based on judgment and an application of elements of the RIIO regulatory framework currently applied to electricity distributors in the UK. Under RIIO, the standard term of a regulatory plan is eight years, although utilities can "fast track" the regulator's evaluation of their regulatory application if they demonstrate good past performance and a well-developed plan for the future. In Ontario, the Board has established five-year terms for the Price Cap IR and Annual IR regulatory options in the RRFE. The Board also found the *minimum* term of a Custom IR plan must be five years, but it did not conclude that Custom IR plans must have five year terms. The Board's RRFE Report therefore left open the option of Custom IR plans in excess of five years.

Dr. Kaufmann believes a variant of the “fast tracking” concept under RIIO can be applied to THESL, only in reverse. RIIO allows expedited regulatory review for distributors demonstrating good past performance and a well-developed plan for the future. PEG’s assessment of PSE’s work indicates that the Company has displayed bad reliability performance in the past and present, and its cost performance is projected to decline in the future. It is therefore prudent for the Board to exercise greater oversight of THESL’s plan to ensure that it is delivering the promised value (*e.g.* in terms of improved reliability) for the money. Enhanced oversight and scrutiny is likely to be facilitated by spreading the plan out over eight years rather than concentrating it in five years. This approach also enables the regulatory treatment and recovery of expenditures in years six through eight of the plan to be informed by the Board’s assessment of THESL’s cost and reliability outcomes in the plan’s first five years.

c) Did PEG consider any other term (e.g., six, seven or ten years)?

No, because the recommendation was based (in part) on the RIIO precedent.

d) If the answer to part “c” is yes, please provide the reasons why PEG concluded that an eight-year term was preferable?

Not applicable.

1-THSL-56.

<u>Reference: PEG Report, p.17 paragraph 4, and p.18 Figure 1 (Figure 6 in PSE Report): "However, if THESL was exhibiting continuous improvement in its reliability and cost performance, it would be moving in the southwest direction on PSE's Figure 6, towards the "reliability better, cost better" quadrant.</u>

Please state whether PEG believes that the cumulative effect of adjustments to Toronto Hydro's rate-setting formula proposed by PEG in its report would result in the utility's two-dimensional performance (cost and reliability) moving in the "southwest" direction on the PSE cost/reliability performance graph.

> Yes. PEG believes its proposed adjustments to THESL's rate-setting formula is more likely to move the Company's cost and reliability performance in the indicated "southwest" direction compared to THESL's Custom IR proposal.

1-THESL-57.

Please describe the concepts of “pacing” and “prioritization” as utilized by the OEB in the renewed Regulatory Framework for Electricity (RRFE) documentation. Please list the OEB’s criteria and/or general direction with respect to integrating these concepts into the utilities’ capital evidence.

One of the initiatives in the RRFE was Distribution Network Investment Planning (EB-2010-0377). On November 8, 2011, Board Staff released a Staff Discussion Paper on this issue. In the Board’s October 18, 2012 RRFE Report, the Board presented its findings on this initiative in Chapter Three, “Distribution Infrastructure Investment Planning,” of the RRFE Report. A series of working group meetings on this topic was held after the release of the RRFE Report, but no subsequent “RRFE documentation” (*i.e.* Staff Discussion Papers or Board Reports) was released. The “concepts of ‘pacing’ and ‘prioritization’ as utilized by the OEB” are therefore incorporated in Chapter Three of the RRFE Report.

There are six references to these concepts in Chapter Three of the RRFE Report.

- On page 28, the Board writes that “…a multi-year approach better accommodates planning for large investments and allows greater scope to prioritize and pace investments and smooth rate increases.”

- On page 31, the Board writes that it “further concludes that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles. This time horizon, along with the integrated approach to planning, will allow distributors to pace and prioritize projects with a view to the impact on the total bill for customers.”

  As explained in the response to THESL Interrogatory 55b), in a regulatory context, the reference to a “horizon of five years” refers to what the Board found to be the *minimum* term for Custom IR terms; the RRFE Report leaves open the option of longer terms for planning capital spending and recovering that spending through Custom IR plans.

- On page 35, the Board writes that “where no asset management plan is available, the distributor must file information outlining its approach to the planning and prioritization of capital projects.”

- On pp. 36-37, the Board writes “some stakeholders were supportive of a requirement that distributors consider forecasts of the ‘total bill’ when developing their spending plans, identifying this as essential to the pacing and prioritization of investment in a manner that controls year-over-year rate increases and to reducing the need for mitigation at the time of Board approval.”

- Page 37 also says “the Board will further engage stakeholders on the identification of qualitative and quantitative approaches and tools to be used by distributors to support their investment proposals, including methodologies to assist in prioritizing and pacing their proposed investments in consideration of the total bill impact on customers.”

- On page 52, the RRFE Report says “in order to implement the Board’s requirements for integrated infrastructure planning, the Board will identify tools and methods to support proposed infrastructure investments in distributor applications, including the demonstration of how the distributor has optimized, prioritized, and paced investments to take into consideration the total bill impact on customers.”

Based on this review of the most relevant RRFE documentation, PEG believes the Board’s use of the “pacing” and “prioritization” concepts is motivated by a desire to “smooth” and “control” annual rate increases, “in consideration of the total bill impact on customers.” This rationale is also reflected in Dr. Kaufmann’s recommendation to extend THESL’s capital investment program over eight years instead of concentrating it in five years.

1-THESL-58.

a) Please provide PEG's definition of a comprehensive rate setting plan.

> PEG shares the Board's view on comprehensive rate-setting. As stated in the RRFE Report, and reprinted on page 51 of the PEG Report, the Board "continues to support a comprehensive approach to rate-setting, recognizing the inter-relationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the implementation of an outcome-based framework." A comprehensive rate-setting approach therefore recognizes the inter-relationship between capital and OM&A expenditures and creates stronger and more balanced incentives compared with targeted rate-setting.

b) In PEG assessment, does a rate plan where a utility's base rates are adjusted using a Price Cap Index formula, while also utilizing an ICM/ACM mechanism to secure additional capital funding constitute a comprehensive rate-setting plan? If yes, please discuss why this is the case. If no, please elaborate as to why not.

> Yes. As this Interrogatory acknowledges, these regulatory options adjust base rates (capital and non-capital components) using a Price Cap Index. This index is calibrated using external measures of inflation and industry total factor productivity growth. Because the same price cap index is applied to the capital and non-capital costs reflected in base rates, it is a comprehensive rate-setting mechanism.

1-THESL-59.

Please confirm that PEG's total cost benchmarking analysis includes only US utilities and Toronto Hydro. Please further confirm that no other Ontario utilities are included in this data set.

PEG confirms that its dataset included only US utilities and no Ontario utilities other than THESL.

1-THESL-60.

Why did PEG choose to focus on the THESL-US dataset, rather than the “combined” dataset, which contains a larger number of observations and includes distribution utilities operating in Ontario’s legislative, regulatory, economic and geographical context?

> PEG focused on a U.S. only dataset because we have already benchmarked THESL against the Ontario industry, in an econometric benchmarking study that the Board is currently using to assign stretch factors for distributors under Price Cap IR. In addition, PEG believes there is no value in PSE’s Ontario benchmarking, because PSE selected the TFP-based cost measure for THESL while the Ontario distributors were intentionally benchmarked using a different, benchmarking-based cost measure. PSE’s costs for THESL are therefore either incompatible with the costs used to benchmark every other Ontario distributor, or unsuitable for benchmarking. Please see the response to THESL Interrogatory 61 for further details.
>
> Given PEG’s previous benchmarking work of the Ontario industry, the problematic and/or inconsistent cost measures PSE used for THESL and the other Ontario distributors, and the fact that the most unique element of PSE’s work was its use of US utility data, PEG believed our work could be completed most efficiently, without sacrificing any substance, by focusing only on the US-THESL sample.

1-THESL-61.

Please quantify the number of observations included in PEG's US-only data set (where a single observation constitutes one utility in one year). Please do the same for PSE's combined Ontario-U.S. data set

Table Three of the PEG Report shows there were 805 observations in PEG's US-THESL dataset. Table 4 of the PSE Report shows there were 1650 observations in its Ontario-US dataset. Table 7 of the PSE Report shows there were 880 observations in PSE's US-THESL dataset. Because THESL was included in both the Ontario-US and US-THESL datasets, comparing Tables 4 and 7 of the PSE Report indicates that PSE's Ontario sample included 770 observations on other Ontario electricity distributors.

Recall that PSE's benchmarking analysis used the TFP-based cost measure for THESL; PSE did *not* use the benchmarking-based cost measure constructed by PEG for THESL and every other Ontario distributor in order to ensure "apples to apples" benchmarking comparisons in the Province. This implies that every one of PSE's 770 Ontario observations for utilities other than THESL were either: 1) internally inconsistent with the THESL cost definition, if PSE used the benchmarking-based cost definitions for those utilities; or 2) unsuitable for cost benchmarking, if PSE used the TFP-based cost definitions for those utilities. Under either possibility, PEG believes there is no value in PSE's benchmarking analysis for Ontario electricity distributors.

1-THESL-62.

Please confirm whether PEG agrees that in general a single econometric study with a single data set would be less reliable than two econometric studies with two complementary subsets of that identical data set?

PEG does not agree with this statement.

1-THESL-63.

Reference: PEG Report, p.21, paragraph 2: “PEG therefore confines our review to PSE results derived from the US-Only sample. This focus will streamline our review without any loss of substance.”

Please provide the basis for the statement that using the US-only sample approach will not lose any substance relative to a US-Ontario sample.

Please see the remainder of sentence referenced in the preamble.

1-THESL-64.

PEG's Report recommends a stretch factor for THESL ranging as high as 1.0%.

a) Please confirm that the 1% value is arrived at using only total cost econometric benchmarking results.

> Not confirmed; the 0.6% to 1.0% recommended stretch factor range is explicitly based on both cost and reliability benchmarking results for THESL. Please see pp. 49-50 of the PEG Report.

b) Toronto Hydro has proposed using PSE's total cost econometric benchmarking model using a combined US-Ontario data set to set the Toronto Hydro stretch factor. Please specify the exact study/studies and corresponding data set that form the basis of PEG's proposed stretch factor for Toronto Hydro.

> Please see Chapters 3 and 4 of the PEG Report.

c) Given that THESL's proposed stretch factor would be determined using the Board's stretch factor values and group demarcation points, please confirm whether in PEG's view a 1.0% stretch factor deviates from Board policy in this regard.

> No; the Board has not established a policy for setting stretch factors in Custom IR plans.

d) Please describe in detail the exact methodology that PEG used to arrive at the incremental 0.4% of stretch factor that it is proposing. Please explain in detail how this methodology rules out all other amounts of incremental stretch (i.e., 0.3%, 0.2%, 0.1% and any number in between these values).

> PEG has not proposed an "incremental 0.4% of stretch factor;" we have recommended a stretch factor range of between 0.6% and 1.0%. We have recommended a range rather than a specific value to reflect the benchmarking evidence that has been presented on THESL's cost and reliability performance, rather than simply its cost performance, which was the basis for the Board's previous stretch factor decisions. PEG believes this broader range of evidence may provide a basis for the Board to exercise its discretion in a manner to ensure that customers benefit from incentive regulation plans, if the Board deems this to be appropriate. See pp.49-50 of the PEG Report.

1-THESL-65.

<u>Reference: PEG Report, p. 42, paragraph 5.</u>

a) In the referenced passage PEG concludes that THESL's SAIDI is 20.6% *above* the benchmarks for the 2009-2011 period. Please review PEG's output and confirm its finding that THESL's SAIDI is actually 20.6% *below* the benchmark value for 2009-2011.

Confirmed.

b) If PEG confirms that its finding that THESL's 2009-2011 SAIDI is 20.6% below the benchmark, does PEG's reliability finding better align with PSE's finding of THESL's SAIDI being historically below benchmark values?

No; the relevant conclusion is that there is no statistically significant difference between THESL's actual and predicted SAIDI.

1-THESL-66.

Please confirm that PEG's SAIDI evaluation finds that THESL's SAIDI performance is projected to be 115.6% below benchmark values in 2019. Please comment on whether this level of performance constitutes a positive outcome for the utility and its ratepayers.

> Not confirmed. Please see the response to Interrogatory 4 b). PEG did not benchmark THESL's projected SAIDI or SAIFI performance, because the credibility of benchmarking projected reliability depends on understanding the bases for how the projected values for SAIFI and SAIDI are calculated, and PEG does not believe THESL has provided sufficient information to understand the derivation of these projections. While PEG has "inputted" all THESL SAIFI and SAIDI values (historic and forecast) into our reliability benchmarking models, we put no weight on THESL's reliability projections presented in this proceeding and, accordingly, have not reported any such projections in the PEG Report.

Board Staff/PEG Response to Energy Probe Interrogatories
Custom Incentive Rate-Setting Application for 2015 to 2019
Electricity Distribution Rates and Charges
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January 16, 2015

1 - Energy Probe – 1

Ref: PEG REPORT, Chapter 4, Page 39

Preamble:

Precipitation is correlated with vegetation and wildlife, both of which are common causes of interruptions. For all three of these variables, the expected sign on the SAIDI and SAIFI coefficients are expected to be positive, because higher values for HDD, CDD, and precipitation are all expected to be associated with higher SAIDI and SAIFI values.

a) Why is PEG using Precipitation rather than a Percent Forestation variable (PSE) in its model?

   Please see the response to THESL Interrogatory 45.

b) What can the PEG Model tell us about the relationship between Precipitation and Tree Contact and Vegetation Management and Outages?

   The PEG SAIFI and SAIDI models indicate that there is a positive relationship between precipitation and outages, and many of those outages undoubtedly occur through tree contacts, since all else equal tree growth will be greater in areas with greater precipitation. However, the PEG SAIFI and SAIDI models cannot provide any information on the role of distributors' vegetation management activities on outages, although this issue can potentially be explored in simultaneous cost-benchmarking studies.

c) Given THESLs high Tree Contact outage history, can the PEG model be used to inform decisions on increasing/decreasing the investment in THESL's Vegetation Management Program? Please Discuss.

   No; please see the response to part b) of this Interrogatory.

d) Can simultaneous benchmarking of cost and reliability be applied to individual Reliability subsets such as Tree Contact, Defective Equipment etc.? Please discuss how this would be done for both SAIDI and SAIFI.

These issues can potentially be explored through simultaneous cost and reliability benchmarking, although in practice this may be difficult since distributors typically do not provide direct, publicly-available data on their vegetation management operational expenses *per se* or replacement expenditures for defective equipment. The feasibility of such benchmarking would have to be explored to determine whether sufficient data, including suitable proxy variables, are available for a large enough sample of utilities to address these issues.

1 - Energy Probe – 2

Ref: PEG REPORT, Chapter 5, Page 45

Preamble:

If the Board is asked in the future to assess the statistical relationship between cost and reliability in regulatory applications, effort should be directed towards developing appropriate simultaneous benchmarking models rather than relying on statistical tools that are not fit for this purpose.

a) If customers want improved reliability what tools are available to inform the link between Cost (CAPEX and OM&A) and Reliability SAIFI/SAIDI?

PEG is not aware of any tools that have been developed that address this link rigorously. However, as referenced in the preamble of this question, simultaneous benchmarking models can in principle be developed that inform understanding of this relationship.

b) THESL has provided Projections for Improved Reliability.

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TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ENERGY PROBE RESEARCH FOUNDATION

Measure[1]	2014 Forecast	2015 Projection	2016 Projection	2017 Projection	2018 Projection	2019 Projection
SAIDI	0.97	1.16	1.1	1.05	1.01	0.95
SAIFI	1.31	1.39	1.28	1.2	1.11	1.03
CAIDI	0.74	0.83	0.86	0.87	0.91	0.92
FESI						
MAIFI	2.76	2.36	2.24	2.13	2.02	1.91

What weight should be placed on these metrics and projections and the relationship to the increased CAPEX (and to a lesser degree) OM&A Program under the CIR Plan.? Please provide PEG's opinion(s).

Please see the responses to THESL Interrogatories 4b) and 66.

1 - Energy Probe – 3

Ref: PEG REPORT, Chapter 7, Page 55

Preamble:

PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "**urban core dummy"** variable from PSE's econometric cost model, PEG found THESL's costs were 9.7% above its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan.

a) Please clarify the relationship between percentage of Distribution Underground and Urban Density.

   Underground plant is more prevalent in urban than rural areas, so there is generally a positive relationship between the percentage of distribution plant that is underground and urban density.

b) Please discuss if the higher costs of underground transformers and other assets are only justified in high density Urban Cores.

   While there is typically a positive relationship between density and undergrounding, it is too sweeping to conclude that the higher costs of underground transformers and other assets are "*only* justified in high density urban cores" (italics added). A counter-example is the System Modernization and Reliability Project (SMRP) that was approved for Wisconsin Public Service (WPS) in 2013. The main focus of the SMRP was undergrounding existing electricity distribution assets in order to improve reliability. Many, if not most, of these assets were located in rural areas. However, Dr. Kaufmann's work for WPS indicated that the value of the reliability improvements expected to result from this project exceeded the costs of the SMRP. This evidence implies that the higher costs of undergrounding assets are not necessarily *only* justified in high density urban cores. Please see the response to THESL Interrogatory 39 e).

1 - Energy Probe – 4

Ref: PEG REPORT, Chapter 7, Page 55

Preamble:

PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level, but we find the Company's SAIDI is not statistically different from its expected level.

a) In PEG's view, is SAIDI or SAIFI most important? Or alternatively are both appropriate performance measures. Please discuss.

PEG believes SAIFI and SAIDI are both appropriate performance measures. However, Dr. Kaufmann believes SAIFI is "more important" than SAIDI in the sense that customers generally value SAIFI more highly than SAIDI. The conceptual and empirical support for this conclusion is presented below.

The "outage cost"/value of reliability literature suggests that outages impose both fixed and variable costs on customers. Fixed costs are those that occur immediately when, for example, service interruptions disrupt an industrial customer's production plans. Variable costs are related to the duration of an outage.

Let the system–wide cost for each outage, *i*, be given by

$$C_i = a + bh_i \qquad [4.1]$$

Here, C_i is the cost of the outage and h_i is the total duration of the outage experienced by customers on the system. This simple, linear expression says that outage costs can be decomposed into two components. The fixed costs, *a*, are incurred immediately as power interruptions disrupt customers' use of electricity. The variable costs, bh_i, are related to the length of the outage. The function is general enough to include the possibility that some customers will have no fixed cost. If that was true system–wide, then $a = 0$ and the line passes through the origin of the graph.

Total annual outage costs are obtained by summing the costs per outage in [4.1] over the number of outages in each year. Total outage costs in each year, t, are therefore equal to

$$TC_t = \sum_i \left(a + bhi\right) = N_t a + b\sum h_{i,t} \qquad [4.2]$$

Here, N_t stands for the number of interruptions experienced in year, t. The average outage costs experienced by customers on the system can be obtained by dividing [4.2] by the average number of customers served in year t, or $Cust_t$. Therefore

$$\frac{TC_t}{Cust_t} = a\frac{N_t}{Cust_t} + b\frac{\sum h_{i,t}}{Cust_t} \qquad [4.3]$$

In equation [4.3], $\frac{N_t}{Cust_t}$ corresponds to the average number of interruptions experienced by a customer on the system in year t. This is equivalent to the value of SAIFI in that year, or SAIFI_t. Similarly, $\frac{\sum h_{i,t}}{Cust_t}$ stands for the total duration of outages experienced by an average customer on the system in year t. This is equivalent to the value of SAIDI in that year, or SAIDI_t. Equation [4.3] therefore implies that the annual outage costs experienced by an average customer is a linear function of values for SAIFI and SAIDI. SAIFI is multiplied by the average fixed costs associated with an outage. SAIDI is multiplied by the average variable costs associated with a typical outage. If there are no fixed costs, then outage costs in year t are equivalent to the value for SAIDI_t multiplied by the average outage cost.

Equation [4.3] applies for all periods, so between two years t and $t+1$, the change in outage costs experienced by customers on the system, on average, is equal to:

$$\frac{TC_{t+1}}{Cust_{t+1}} - \frac{TC_t}{Cust_t} = \left(a\frac{N_{t+1}}{Cust_{t+1}} + b\frac{\sum h_{i,t+1}}{Cust_{t+1}} \right) - \left(a\frac{N_t}{Cust_t} + b\frac{\sum h_{i,t}}{Cust_t} \right)$$

$$= a\left(\frac{N_{t+1}}{Cust_{t+1}} - \frac{N_t}{Cust_t} \right) + b\left(\frac{\sum h_{i,t+1}}{Cust_{t+1}} - \frac{\sum h_{i,t}}{Cust_{i+t}} \right) \qquad [4.4]$$

$$= a\left(SAIFI_{t+1} - SAIFI_t\right) + b\left(SAIDI_{t+1} - SAIDI_t\right)$$

Equation [57.4] implies that the change in outage costs for an average customer is a linear function of changes in values for SAIFI and SAIDI. The change in SAIFI is multiplied by the average fixed costs associated with an outage. The change in SAIDI is multiplied by the average variable costs associated with an outage.

Dr. Kaufmann's testimony on the SMRP for WPS (referenced in Energy Probe Interrogatory 3b)) can be used to infer the relative value of fixed and variable outage costs and hence, from equations [4.3] and [4.4] above, customers' relative valuation of SAIFI and SAIDI. Dr. Kaufmann's Sur-Surrebuttal testimony for WPS relied on an analysis of the "willingness to pay" (WTP) outage cost literature undertaken for the Lawrence Berkeley National Laboratory (LBL). On page 4, lines 1 through 7 of this testimony, Dr. Kaufmann reports the following LBL finding on the outage costs experienced by residential customers:

> "The two most robust estimates (of the value of reliability) for duration are the 1-hour and 4-hour as these two scenarios were used in multiple studies across multiple regions. The average cost per (outage) event for a 1-hour using a WTP methodology is $6.90, and the average for a 4-hour is $7.14, suggesting only a modest impact of duration on residential customers' willingness to pay to avoid an outage."

Thus, the LBL study finds that the "two most robust estimates" of outage valuations are that residential customers are willing to pay $6.90 to avoid a one-hour outage and $7.14 to avoid a four-hour outage. These estimates can be integrated into equation [4.1] above to estimate the values of a and b.

If the WTP to avoid a one-hour outage is \$6.90, this implies

$6.90 = a + b *1 [4.5]

Where a = the fixed cost experienced with the occurrence of the outage, and b = the cost associated with each hour of outage duration.

Similarly, if the WTP to avoid a four-outage is \$7.14, then

$7.14 = a + 4b [4.6]

Equation [4.5] can be expressed as a = \$6.90 – b. When this expression is substituted into equation [4.6], we have

$7.14 = ($6.90 – b) + 4b [4.7]

$0.24 = 3b

$0.08 = b

Given this value for b, a will be equal to \$6.82. Recall that the a term reflects the relative value of SAIFI while b reflects the relative value of SAIDI. This implies that, in a one-hour outage, 98.8% of the costs imposed on customers are associated with SAIFI and the occurrence of the outage itself (*i.e.* 6.82/6.90 = 0.988) while only 1.2% of customer costs are associated with outage duration and SAIDI. PEG believes this is strong evidence that reducing SAIFI is more important and valuable to customers than reducing SAIDI, particularly since PEG's conclusion is based on the "two most robust estimates" of the value of reliability cited in a study for the respected and objective Lawrence Berkeley National Laboratory.

b) Is benchmarking SAIDI or SAIFI to CAPEX valid for both measures? Please discuss.

Yes. PEG believes SAIFI can be impacted by capital expenditures. Since SAIDI is equal to SAIFI * CAIDI, the impact of capital expenditures will also be reflected in SAIDI, at least indirectly.

1 - Energy Probe – 5

Ref: PEG REPORT, Chapter 7, Page 56

Preamble:

PEG believes there may be value to ratepayers in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization of capital spending, while at the same time managing the pace of rate increases for customers. PEG therefore recommends that the capital expenditures in THESL's Custom IR plan be spread out over eight years (2015-2022) rather than concentrated in five years (2015-2019).

a) Is PEG recommending extending the CIR Plan Period from 2014-2019 to 2022?

No; please see the response to THESL Interrogatory 55 b).

b) If NO, provide a revised analysis of the CAPEX 2014-2019 and associated PCI Price index in the format of Table 8.

Please see the response to THESL Interrogatory 55 b). As stated on page 56 of the PEG Report, the C_n values on Table Eight of the PEG Report were computed simply by multiplying THESL's recommended C_n value in each year of the plan by (5/8). No adjustments of Table Eight in the PEG Report are necessary.

c) If YES please explain the rationale for departing from the RRFE Framework.

PEG does not believe its recommendation departs from the RRFE Framework. Please see the response to THESL Interrogatory 55 b). THESL is only required to adjust the timing of its capital expenditures to be consistent with the recommended funding levels. This can be accomplished in myriad ways, such as slowing the annual spending on any given project, or by deferring the start of some projects to later years.

d) Please provide a revised analysis 2014-2022 in the format of Table 8.

PEG cannot provide any analysis for the years 2020-22 because a separate regulatory plan would be implemented in those years; it cannot be assumed that this plan will be an extension or modification of the Company's current IR proposal, or PEG's proposed adjustments of that proposal.

Table Eight

Comparison of Custom PCI Values between Toronto Hydro and PEG for Custom IR Period

	Toronto Hydro				PEG			
Year	2016	2017	2018	2019	2016	2017	2018	2019
Inflation	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
X = Stretch Factor	-0.3%	-0.3%	-0.3%	-0.3%	-0.6%	-0.6%	-0.6%	-0.6%
Cn	4.10%	7.56%	6.67%	5.01%	2.56%	4.73%	4.17%	3.13%
Stretch Factor * Scap	N/A	N/A	N/A	N/A	-0.40%	-0.41%	-0.42%	-0.43%
Billing Determinant Adjustment	N/A	N/A	N/A	N/A	-1.50%	-1.50%	-1.50%	-1.50%
Scap	67.10%	69.20%	70.80%	71.90%	66.90%	68.50%	70.22%	71.35%
Change in Custom PCI	4.56%	7.99%	7.08%	5.40%	1.03%	3.16%	2.58%	1.52%
Average Annual PCI Growth				**6.26%**				**2.07%**

Board Staff/PEG Response to VECC Interrogatories
Custom Incentive Rate-Setting Application for 2015 to 2019
Electricity Distribution Rates and Charges
EB-2014-0116
January 16, 2015

1.0 Board Staff Evidence

"PEG Reports" refers to December 2014 Study entitled: Toronto Hydro Electric System Limited Custom IR Application and PSE Report – Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliability Levels – Assessment and Recommendations.

1.0 – VECC -1

Reference: PEG Report /pg.4

a) Please explain what steps PEG took to identify the source and verify PSE's SAIFI and SAIDI observations.

PEG began by comparing the reliability data PSE provided to the sources from which PSE said it extracted these data. This comparison indicated that PSE did not indicate the sources from which it obtained a significant share of its reported SAIFI or SAIDI data. For the observations where PSE did indicate and/or provide the data source, PEG compared PSE's reported values for SAIFI and/or SAIDI to the values that were reported in those source documents, and other publicly available data PEG was aware of for the same SAIFI and SAIDI observations.

1.0 – VECC- 2
Reference: PEG Report/ pg. 50

a) Please provide the "*precedents for stretch factors of 1% in North American incentive regulation*."

   PEG is aware of two cases where explicit, 1% stretch factors have been implemented in North American incentive regulation. One was in the 1997-2002 plan approved for Southern California Gas (where the stretch factor increased over the term of the plan until its value was 1%). The second was in the 2002-2011 plan approved for Berkshire Gas in Massachusetts.

1.0 VECC – 3

Reference: PEG Report / pg. 56-57

Pre-amble: The PEG modifications result in an average annual PCI growth of 2.07% in contrast to the 6.26% average annual growth of the THESL rate plan. Approximately 50% reduction is attributed to deferring capital expenditures.

a) Please provide the detailed calculation supporting the 50% reduction by deferring capital spending.

The recommendation to spread THESL's Custom IR plan over eight years rather than concentrating it in five years was based on a judgment and an application of the RIIO precedent, not a "detailed calculation." See the response to THESL Interrogatory 55 b) for details. As stated on page 56 of the PEG Report, the C_n values on Table Eight of the PEG Report were computed simply by multiplying THESL's recommended C_n value in each year of the plan by (5/8).

b) THESL has completed a Distribution System Plan (Exhibit 2B) in support of its capital plan. The Utility suggests that the capital program "*represents a minimum level of appropriate investment given the distribution system's needs*.." (Exhibit 1B/Tab2, Schedule 4, pg.1). In light of this how would PEG suggest THESL re-evaluate and redefine its 5 year plan?

PEG is only recommending that the period over which the plan is implemented be extended from five years to eight years. PEG is not making any suggestions as to how THESL should re-evaluate and redefine its 5 year plan. In the event the Board was to accept PEG's recommendation, any re-evaluation/redefinition would have to be determined by THESL, as would normally be the case when the Board mandates a change from what is proposed in an application.