PEG Responses to Pollution Probe

M3-PP-1

Reference: Clearspring developed an econometric model of total power distributor cost using operating data from 78 U.S. electric utilities, mostly over the 2007-2021 period. [M3 Evidence, Page 6]

Interrogatories

a) Please explain what significance is of the 2007-2021 reference period and what data was outside that period.

b) Please explain if a more recent period interval would mitigate lower relevance of the older data.

c) If a more recent interval period was used (e.g. 2015-2021), please explain what the impacts would be.

Responses:

The following responses were provided by PEG.

a) PEG chose a fifteen-year sample period for its econometric cost models in order to make the parameter estimates more pertinent to a forecasting exercise. The parameter estimates for the trend variables are of special interest because they have a bearing on the appropriate cost efficiency growth factor. The relevance of these estimates is discussed on pp. 57-58 of PEG's empirical research report. The size of the sample should be adequate for the estimation of parameter estimates. The benchmarking results of this study are not very sensitive to the sample period used for model estimation.

b) Please see the answer to part a) of this question.

c) The impact of using a short sample period is unclear. Model parameter estimates would become less accurate due to the smaller number of observations. PEG believes using only seven years of data is not desirable if more data are available.

M3-PP-2

Reference: The Company's forecasted/proposed capital cost is about 38% above our model's prediction on average during the five years of the proposed new CIR plan. [M3 Evidence, Page 8]

Interrogatories

a) Please explain how the future model prediction over the 2025-2029 term was calibrated to include current/future impacts not fully reflected in historical data (e.g. acceleration of the energy transition, electrification and DERs).

b) Please explain if future costs should align with historical costs or if there are sufficient drivers to make adjustments to capital and/or O&M budgets for the future 2025-2029 term.

Responses:

The following responses were provided by PEG.

a) As noted in response to the prior question, PEG used a more recent sample period than Clearspring. The forecasted cost benchmarks reflect the Company's forecast of growth in its peak demand. The Company explains its forecasted capital expenditures and labor cost growth as being chiefly due to large replacement capex and smart grid initiatives.

b) PEG's total cost model, like Clearspring's, measures deviation from long-run capital costs. There are no factors or adjustments to calibrate the model's predictions other than the business conditions contained in the model based on historical data. The introduction of such future cost drivers into the model is only expected to be predictive to the extent that the cost of these items is in the historical data and well-measured business conditions can be developed.

   To the extent that Toronto Hydro's cost forecast contains these extraordinary costs that the model does not predict, it is reasonable to itemize these costs and use this as evidence to partially explain their poor cost performance.

M3-PP-3

Toronto Hydro indicates that higher budgets in 2025-2029 should provide a basis for lower costs in future terms.

Interrogatories

a) Is PEG aware of that being an argument used by other utilities?

b) What mechanisms are available (or used) to ensure that future costs are in fact reduced so the increased spending over the term does not just become a new baseline for future IRM terms?

Responses:

The following responses were provided by PEG.

a) This specific argument is occasionally advanced by utilities. Investments in advanced metering infrastructure ("AMI"), for example, have been touted as reducing certain OM&A expenses. This argument can also be used for a capex surge because surge capex gradually depreciates, thereby slowing cost growth. And of course capex today reduces the need for future capex even if it is premature.

   To the extent that the Company means that smart grid and other expenditures today reduce OM&A expenses tomorrow PEG notes that THESL has asked for full recovery in this plan of an OM&A cost bump. This raises a concern about overcompensation over multiple plans that PEG has frequently mentioned about CIR.

b) PEG does not know all of the mechanisms that are available but believes that this is a legitimate area of inquiry for the Board in future proceedings. A large Illinois utility (Commonwealth Edison) once had a PIM that considered whether certain cost savings triggered by advanced metering infrastructure were actually achieved.

PEG Responses to School Energy Coalition
Statistical Cost Research for THESL's New CIR Plan

M3-SEC-14

[M3, p.6] PEG references Clearspring's comments during the Technical Conference that it had not updated its model with Toronto Hydro's 2023 actual data, or investigate whether such an update was likely to be material.

Interrogatory:

a) Please confirm PEG did not use 2023 actual data in its analysis.
b) If confirmed, please provide PEG's view of the directional impact of using 2023 actual data on both its and Clearspring's benchmarking results.
c) Please confirm PEG's 2025-2029 forecast benchmarking results are based on Toronto Hydro's updated forecast costs filed on January 29, 2024. If not, please update the benchmarking and TFP results.

Response:

The following responses were provided by PEG.

a) This statement is confirmed.
b) We relied on Clearspring's cost data in our econometric models. The capital and OM&A cost definitions in the econometric models require adjustments from the high-level capital additions and OM&A totals Toronto Hydro provided in the updates. PEG cannot confirm whether all of the necessary 2023 actual data for the econometric cost definitions were provided. As Clearspring did not provide updated 2023 numbers with the appropriate adjustments for the model definitions, PEG cannot comment on the directional impact.
c) This is not confirmed. As discussed in part b) PEG does not have access to the econometric cost adjustment details for the 2023-2029 period.

   To provide a notion of the possible impact on benchmarking scores, PEG calculated the percentage change in Toronto Hydro's total capital additions and total OM&A expenses from the revised forecasts. This did not take account of adjustments to the data that might occur in a proper benchmarking exercise. We then estimated Toronto Hydro's hypothetical cost performance by applying those same percentage changes to the econometric cost forecasts that we previously used. The percentage changes in the costs and in the resulting cost performance for Toronto Hydro can be found in the following table. We have included our corrected total cost benchmark results for PEG's report models for comparison[1].

How Toronto Hydro Cost Benchmarking Scores Might Change with New Data

	Total Cost Benchmark Scores		Capital Cost Benchmark Scores		OM&A Cost Benchmark Scores	
Year	**PEG Corrected Report Model**	**Scores with *Estimated* Changes to Econometric Cost Forecasts**	**PEG Corrected Report Model**	**Scores with *Estimated* Changes to Econometric Cost Forecasts**	**PEG Corrected Report Model**	**Scores with *Estimated* Changes to Econometric Cost Forecasts**
2023	22.89%	20.34%	30.14%	27.98%	23.31%	19.46%
2024	24.52%	25.90%	31.24%	33.48%	26.12%	24.61%
2025	26.62%	27.56%	33.14%	34.36%	28.23%	28.22%
2026	28.92%	28.96%	35.54%	35.59%	29.41%	29.39%
2027	30.82%	30.75%	37.94%	37.85%	28.91%	28.89%
2028	32.92%	32.82%	40.18%	40.06%	29.67%	29.66%
2029	35.18%	33.79%	42.86%	41.09%	29.69%	29.68%
Averages						
Forecast Period 2023-29	28.84%	28.59%	35.86%	35.77%	27.90%	27.13%
CIR Period 2025-29	30.89%	30.78%	37.93%	37.79%	29.18%	29.17%

[1] The corrected models can be found in N3-TH-025, part a).

M3-SEC-15

Interrogatory:

[M3] Please provide the following:

a) Figures 1, 2, and 5 in a tabular format in Excel.
b) Tables 8, 9a, 9b, 11a, and 11b in Excel.

Response:

The following responses were provided by PEG.

a) The requested figures are provided in Attachment N3-SEC-15a.
b) The requested tables are also provided in Attachment N3-SEC-15a.

M3-SEC-16

Interrogatory:

[M3, p.25] Please explain why Approach 4 in Figure 5 goes back to 2018, when the approach is about forecasting 2023 to 2029 change in skyscraper completions.

Response:

The following responses were provided by PEG.

The 2018 start year was simply a stylistic choice to include visual context for recent cost performance and the baseline of Clearspring's model with corrections without sacrificing the forecast details.

M3-SEC-17

[M3, p.25-26] PEG provides an analysis of the impact of its identified major concern with congested urban variable in the Clearspring model. Yet, no similar analysis has been provided for the other major concerns identified where it has provided a recommended model correction.

Interrogatory:

For each of the following major concerns, please provide the individual impact of just making the PEG's correction:

a. Area variable – full translog treatment as a scale variable.

b. Area variable - incorrect service territory area value.

c. Substation Data - data were not sufficiently cleaned and vetted.

Response:

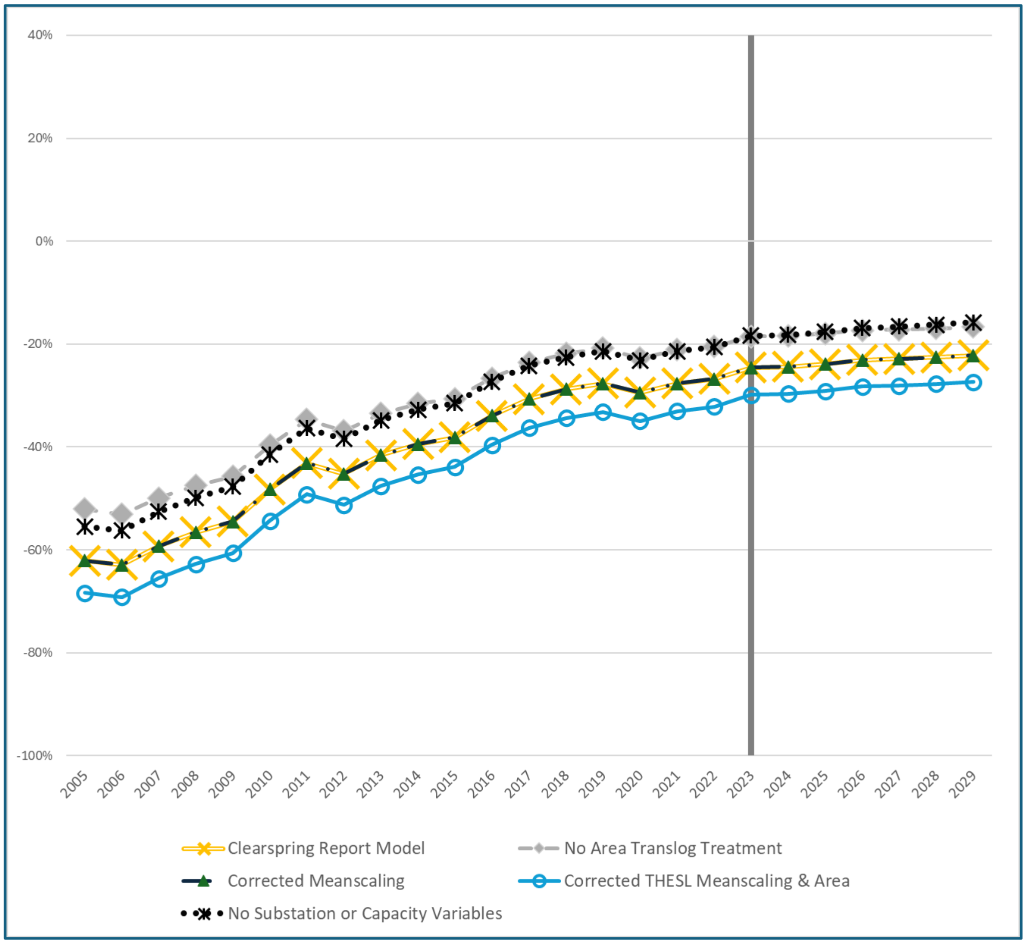
The following response was provided by PEG.

The table below presents Toronto Hydro's cost scores produced by Clearspring's model for each individual change separately. Clearspring loaded its already-mean-scaled variables into the econometric database rather than mean scaling using the econometric software. As a result, it was necessary for PEG to perform the corrected mean scaling procedure with the corrected Toronto Hydro service territory area value. PEG has provided an additional column for the results of using the corrected mean scaling procedure only. Those results have no changes to the area variable value in order to isolate the effects of the area variable correction. A figure illustrating the results is also provided below.

Table N3-SEC-17

Year	Clearspring Report Model	No Area Translog Treatment	Corrected Meanscaling	Corrected Meanscaling & THESL Area	Remove Substation & Capacity Variables
2005	-62.10165%	-52.06127%	-62.10098%	-68.34326%	-55.41287%
2006	-62.88118%	-53.06644%	-62.88071%	-69.15808%	-56.23579%
2007	-59.27401%	-49.88413%	-59.27277%	-65.53450%	-52.60506%
2008	-56.54240%	-47.51959%	-56.54173%	-62.74738%	-49.83063%
2009	-54.46911%	-45.70684%	-54.46787%	-60.62040%	-47.72015%
2010	-48.23561%	-39.63404%	-48.23475%	-54.33540%	-41.46605%
2011	-43.13602%	-34.64451%	-43.13536%	-49.20273%	-36.36971%
2012	-45.23087%	-36.86047%	-45.22953%	-51.25351%	-38.43966%
2013	-41.61787%	-33.44564%	-41.61663%	-47.56756%	-34.79519%
2014	-39.46133%	-31.57368%	-39.46018%	-45.34006%	-32.77473%
2015	-38.12227%	-30.61962%	-38.12132%	-43.87665%	-31.45218%
2016	-33.88968%	-26.59130%	-33.88834%	-39.58664%	-27.29654%
2017	-30.68886%	-23.63091%	-30.68800%	-36.30648%	-24.19548%
2018	-28.78943%	-21.83008%	-28.78838%	-34.38377%	-22.57090%
2019	-27.64206%	-20.83168%	-27.64063%	-33.17900%	-21.41514%
2020	-29.43363%	-22.72635%	-29.43249%	-34.93710%	-23.16952%
2021	-27.63672%	-21.11969%	-27.63538%	-33.05807%	-21.35506%
2022	-26.80349%	-20.49913%	-26.80273%	-32.14808%	-20.54043%
2023	-24.57714%	-18.49499%	-24.57609%	-29.84648%	-18.35594%
2024	-24.42160%	-18.40639%	-24.42064%	-29.67806%	-18.23416%
2025	-23.87133%	-17.94100%	-23.87009%	-29.10004%	-17.63096%
2026	-23.08464%	-17.30700%	-23.08331%	-28.26672%	-16.85915%
2027	-22.89677%	-17.17138%	-22.89572%	-28.06788%	-16.62922%
2028	-22.57166%	-16.97464%	-22.57023%	-27.70052%	-16.23497%
2029	-22.20974%	-16.67395%	-22.20812%	-27.32658%	-15.81965%

Figure N3-SEC-17



M3-SEC-18

Interrogatory:

[M3, p.34-38] Based on PEG's benchmarking model, please provide for each year between 2025 and 2029:

a) The percentage change in the benchmark total, capital and OM&A costs, for each 1% change in customers.
b) The change in the benchmark total, capital and OM&A costs, for each 1% change peak demand.
c) The change in the benchmark total, capital and OM&A costs, for every additional customer.
d) The change in the benchmark total, capital and OM&A costs, for every 1 MW increase in peak demand.

Response:

The following response was provided by PEG.

a) Please see the table below. We have extended the digits reported since the changes are so small.

Table N3-SEC-18a

Percentage Change in Cost Benchmark Given a 1% Increase in Customers in Each Year 2025-2029			
Year	**Total Cost**	**Capital Cost**	**OM&A Cost**
2025	0.416%	0.480%	0.533%
2026	0.426%	0.486%	0.548%
2027	0.428%	0.487%	0.551%
2028	0.436%	0.492%	0.564%
2029	0.439%	0.493%	0.568%

b) Please see the tables below. The first table shows the change in the cost benchmark if an additional MW of peak demand is added in each year from 2025-2029 and incorporated into the moving average. The second table shows the change if an additional MW of peak demand is added to each of the nine years prior to, and to the year in consideration to increase the entire average MW peak demand in the years from 2025-2029 by 1%.

Table N3-SEC-18b(1)

Percentage Change in Cost Benchmark Given a 1% Increase in MW of Peak Demand in Each Year 2025-2029			
Year	Total Cost	Capital Cost	OM&A Cost
2025	0.054%	0.051%	0.039%
2026	0.105%	0.101%	0.076%
2027	0.157%	0.151%	0.112%
2028	0.207%	0.201%	0.145%
2029	0.257%	0.250%	0.179%

Table N3-SEC-18b(2)

Percentage Change in Cost Benchmark Given a 1% Increase in the Average MW of Peak Demand in Each Year 2025-2029			
Year	Total Cost	Capital Cost	OM&A Cost
2025	0.001%	0.523%	0.406%
2026	0.002%	0.516%	0.389%
2027	0.004%	0.514%	0.385%
2028	0.005%	0.507%	0.369%
2029	0.006%	0.506%	0.365%

c) Please see the table below:

Table N3-SEC-18c

$ Change in Cost Benchmark Given an Addition of One Customer in Each Year 2025-2029			
Year	Total Cost	Capital Cost	OM&A Cost
2025	$0.84	$0.60	$0.19
2026	$0.00	$0.00	$0.19
2027	$0.00	$0.63	$0.00
2028	$0.90	$0.00	$0.20
2029	$0.92	$0.67	$0.00

d) Please see the tables below. As in part b), the first table shows the change in the cost benchmark if an additional MW of peak demand is added in each year from 2025-2029 and incorporated into the moving average. The second table shows the change if an additional MW of peak demand is added to each of the nine years prior to, and to the year in consideration to increase the entire average MW peak demand in the years from 2025-2029 by 1%.

Table N3-SEC-18d(1)

$ Change in Cost Benchmark Given an Addition of One MW of Peak Demand in Each Year 2025-2029			
Year	**Total Cost**	**Capital Cost**	**OM&A Cost**
2025	$10.87	$7.86	$1.87
2026	$21.34	$15.47	$3.64
2027	$33.26	$24.16	$5.30
2028	$45.67	$31.93	$7.04
2029	$58.84	$41.56	$8.88

Table N3-SEC-18d(2)

$ Change in Cost Benchmark Given an Average Addition of One MW of Peak Demand in Each Year 2025-2029			
Year	**Total Cost**	**Capital Cost**	**OM&A Cost**
2025	$109.54	$76.22	$17.99
2026	$110.10	$76.71	$17.81
2027	$112.06	$79.47	$17.88
2028	$113.73	$80.15	$17.71
2029	$116.77	$82.45	$17.97

M3-SEC-19

[M1, M3] In each of Toronto Hydro's last approved Custom IR plan, the OEB ordered the inclusion of an incremental stretch factor for capital of 0.3%. Toronto Hydro proposed rate framework eliminates this incremental stretch factor on capital.

Interrogatory:

Please provide PEG's views on this aspect of Toronto Hydro's proposal.

Response:

The following response was provided by PEG.

PEG was an early proponent of what came to be called the incremental capital stretch factor. We ventured multiple rationales for this that included the following.

- Capex containment incentives were weakened by basing capital revenue on a capital cost forecast and returning any capital cost underspends to customers.
- Not having a markdown of supplemental capital revenue was inconsistent with the treatment of such revenue in price cap IR, thereby encouraging utilities to choose CIR.
- Full compensation for an expected capital revenue shortfall now would ultimately result in *over*compensation.

The OEB acknowledged only the weak cost containment incentives argument in approving supplemental stretch factors.

In the new plan, these arguments would apply to THESL's proposed demand-related variance accounts. THESL no longer proposes a clawback of underspends for other kinds of capex.

M3-SEC-20

Interrogatory:

[M3, p.71] Please confirm that PEG's recommendation is an X-Factor of 0.70%, made up of .10% productivity factor/cost efficiency growth factor and a 0.6% stretch factor.

Response:

The following response was provided by PEG.

This statement is confirmed. This proposal is based on the supposition that indexing would escalate OM&A revenue.

M3-SEC-21

[M3, p.71] PEG states: “We believe that a 0.10% base cost efficiency trend that is applicable to both the OM&A and capital revenue of THESL is conservative and reasonable.” [emphasis added]

Interrogatory:

What does PEG believe would be a non-conservative, yet still reasonable, base cost efficiency trend that could be applied to Toronto Hydro’s OM&A and capital revenue.

Response:

The following response was provided by PEG.

Certainly one reasonable and less conservative approach to choosing a base cost efficiency growth trend would be to apply the 15-year average TFP growth trend of U.S. power distributors. 15-year averages are commonly used in contemporary X factor calibrations. As shown in Table 11a of the report, the 15-year average annual TFP growth rate of the sampled U.S. power distributors is 0.08% using simple (even-weighted) averages and 0.39% using cost-weighted averages. If indexing applied only to OM&A revenue, it can be noted that over these same 15 years the annual OM&A productivity growth of sampled distributors averaged 0.61% using simple-weighted averages and 1.01% using size-weighted averages. The downside to using OM&A-specific productivity growth targets is that the sources of TFP growth can switch over time between cost categories.

PEG also notes that if THESL wishes to base its revenue requirement on a cost forecast, it presumably is taking into account the effect of numerous changing business conditions (e.g., a need for high replacement capital spending) on its cost that cause productivity growth to deviate from its long-term trend. It is then pertinent to ask if these costs can then be reduced by a longer-term cost efficiency trend like those drawn from an econometric model. PEG’s revised econometric total cost model, which is calculated using fifteen years of data, has a trend variable parameter estimate -.0022.[2] This is commensurate with an annual cost efficiency growth trend of 0.22% exclusive of scale economies.

The bottom line is that a lower cost efficiency growth target may be warranted if THESL will

[2] The corrected models can be found in N3-TH-025, part a).

actually operate under an indexed ARM without supplemental revenue. To the extent that THESL obtains supplemental revenue or a forecasted ARM, a cost efficiency growth target based on longer-term trends may be warranted.

M3-SEC-22

[M3, p.61-62] With respect to the relationship between the inflation and stretch factors:

Interrogatory:

a) Please confirm that the National Grid annual stretch factor (i.e. consumer dividend) differs based on the annual inflation factor, which is based on U.S. GDP PI measure. For example, the higher the inflation factor, the higher the stretch factor.
b) Please provide PEG's view on scaling an assigned stretch factor to the annual inflation factor.

Response:

The following response was provided by PEG.

a) This statement is confirmed.
b) PEG does not believe that the stretch factor should be contingent on inflation. There is no established relationship between inflation and utility productivity growth.

M3-SEC-23

[M3, p.61] Depending on the specific rate framework, the OEB's stretch factors (0% to 0.6%) is generally applied to the change in rates or overall revenue requirement. Those rates or revenue requirements include both embedded historic capital-related costs (i.e. capital related costs that had been undertaken in previous years) and are calculated on a revenue requirements or rates basis (as opposed to reduction against in- service addition costs). This explains why the stretch factors value are small.

Interrogatory:

If the OEB were to approve a stretch factor that was only applicable to incremental costs undertaken in that year (i.e. capital in-service addition costs, and OM&A) what should the stretch factor range be?

Response:

The following response was provided by PEG.

PEG did not state in its report that stretch factors are small because they apply to older capital costs as well as to new expenditures. We further believe that there is no solid foundation in empirical research or economic reasoning for the schedule that the OEB, Massachusetts, or other regulators use to link particular econometric benchmarking results to particular stretch factors.

The requested calculation could not be made in the time and budget available.

PEG Responses to Toronto Hydro-Electric System Limited ("Toronto Hydro") Interrogatories

M3-TH-001

Reference: PEG Clearspring Report, p. 6 "Pacific Economics Group Research LLC ("PEG") is North America's leading consultancy on incentive ratemaking and the benchmarking and price and productivity trend research that supports it. In addition to Ontario, we have provided research and testimony in these areas in numerous other North American jurisdictions."

Interrogatories

a) For all of PEG's electric utility work in the last ten years, please provide a table that shows the target utility, industry (G, T, D, or combination thereof), PEG's client in the proceeding, PEG's TFP industry trend finding, PEG's benchmark finding, PEG's recommended productivity factor, inflation factor recommendation, and PEG's recommended stretch factor. In cases where PEG only provided some but not all the elements above, please leave blank only those elements that PEG did not perform.

b) Please provide all reports within the last ten years produced by PEG in these cited areas.

Responses:

The following responses were provided by PEG.

a) Due to limited time and budget, PEG has provided an updated version of Exhibit N Tab 1, Schedule 1, Attachment 1 from EB-2021-0110. This table is limited to PEG's publicly available studies. Please see Attachment N3-TH-1a for the requested Table.

b) Please see Attachment N3-TH-1b for the requested public reports.

M3-TH-002

Reference: PEG Clearspring Report, p. 6 “Pacific Economics Group Research LLC (“PEG”) is North America’s leading consultancy on incentive ratemaking and the benchmarking and price and productivity trend research that supports it. In addition to Ontario, we have provided research and testimony in these areas in numerous other North American jurisdictions.”

In a recent report conducted on behalf of Hawaiian Electric Company (“HECO”) in Docket No. 2018-0088, PEG filed a report on May 13, 2020 titled, “New X Factor Research for HECO”. This research involved vertically integrated utilities (G, T, and D). PEG recommended a -1.41% X factor and a 0.22% consumer dividend on behalf of HECO.

Interrogatories

a) Please confirm the 0.22% consumer dividend was based on PEG’s statement on p. 29 of that report when PEG states that the average of approved consumer dividends in current plans approved by North American energy regulators is 0.22%.

b) On p. 10 of that report, please confirm or correct as necessary that PEG listed three recent X Factor precedents and these are:

   i. The average itemized MFP growth target in U.S. multi-year rate or revenue cap indexes is about -0.30%.

   ii. The average X factor in the three current U.S. multi-year rate plans is about -1.50%.

   iii. Several recent PBR plans in Ontario have featured a 0% MFP growth target.

c) Please list any new X factor precedents in North America since 2020 that would modify part b.

d) Regarding the X factor average of -1.50% that PEG cited in part b, in PEG's view, why is the X Factor so much lower in the three current plans than the productivity growth target of -0.30%?

e) Please confirm or correct that PEG on p. 26, Table 7 of its HECO report, found an MFP growth trend from 2008-2017 of -0.87% and an input price inflation differential from GDPPI of -1.37%.

f) Did PEG undertake similar input price differential research in the current application? If so, please provide. If not, please explain why PEG did not undertake this research.

g) Does PEG believe a properly calibrated inflation factor and/or an input price differential is an important element in a multi-year revenue plan?

h) Does PEG have evidence that the inflation factor in Ontario is reflective of industry input price inflation for Toronto Hydro? If so, please provide.

i) Please provide the 2008-2017 TFP trend for electric distribution from PEG's HECO model and research.

j) On page 34 of the HECO report, PEG states, "Using established cost theory and econometric methods, we identified drivers of VIEU productivity growth and estimated their productivity impacts. The need for T&D repex was found to be an important driver of MFP growth of sampled VIEUs in recent years." Does the identified need for T&D repex (replacement capital expenditures) within the U.S. sample, mean that PEG is citing this as a reason for its negative TFP finding?

Responses:

The following responses were provided by PEG.

a) That statement is not correct. While PEG recommended a consumer dividend of 0.22% for HECO and the 0.22% value was based on an average of approved consumer dividends in recent plans, the plans in question were current as of August 2019. PEG made that statement on page 29 of its August 14, 2019 report in the Hawaiian Electric IR proceeding. PEG did not subsequently update its consumer dividend recommendation in that proceeding. It is common practice in IR proceedings to use the industry average approved stretch factors when a quality statistical benchmarking study of the company's cost is unavailable. Such a study was impractical given HECO's unique situation in the U.S. utility industry and was not commissioned by HECO or other parties to the proceeding.

b) These statements were correct at the time that the May 13, 2020 report was released. However, this was a proceeding in the United States, where the tendency of the GDPPI to understate utility input price inflation is well-established. The GDPPI had previously been used as the inflation measure in Hawaiian revenue cap indexes. Also, the issue in the proceeding was appropriate multiyear rate plans for utilities that provide generation and transmission as well as distribution services.

c) There have been several North American utility productivity studies and X factor precedents in North America since this report was issued. These result from proceedings that considered MRPs for NSTAR Gas, Hawaiian Electric, U.S. Oil Pipelines, Boston Gas, Eversource Energy's Massachusetts power distributor, and all the Alberta power and gas distributors. Some results of interest can be found in the attachment to our response to M3-TH-001, part a).

d) The X factors are lower because of the tendency of the GDPPI to grow more slowly than the input prices of U.S. utilities. In U.S. IR proceedings, this inflation differential is customarily decomposed into a productivity differential and an input price differential. The multifactor productivity ("MFP") trend of the U.S. private business sector has been brisk. Additionally, utility witnesses in the States have audaciously proposed sizable input price differentials.

e) These statements are confirmed. However, these are results for vertically-integrated electric utilities over a sample period of less than 15 years.

f) It was not necessary to consider the inflation differential between the GDPPI and input price trends of U.S. utilities because the application was to a Canadian utility. Input price differential research based on Canadian data is not customary in Canadian IR proceedings for two reasons. One is that the MFP trend of Canada's economy tends to be close to zero or negative. Another is that Canadian regulators typically approve inflation factors for attrition relief mechanisms ("ARMs") that are based on multidimensional input price indexes that include a provincial labor price index as well as a macroeconomic price index. Notwithstanding this tradition, PEG examined the latest data on the trend of the MFP index of Canada's economy as part of the research that went into its testimony. The results of this investigation are found in the table below. It can be seen that the MFP trend of Canada's economy has indeed tended to be much slower than that of the U.S. economy.

Recent U.S. and Canadian MFP Trends

Year	U.S. Private Business Sector		Canada Business Sector	
2000	87.081		101.215	
2001	87.501	0.48%	101.120	-0.09%
2002	89.227	1.95%	102.186	1.05%
2003	91.314	2.31%	101.584	-0.59%
2004	93.505	2.37%	101.298	-0.28%
2005	94.871	1.45%	101.174	-0.12%
2006	95.149	0.29%	100.508	-0.66%
2007	95.404	0.27%	99.346	-1.16%
2008	94.491	-0.96%	96.953	-2.44%
2009	94.871	0.40%	94.023	-3.07%
2010	97.334	2.56%	95.483	1.54%
2011	96.894	-0.45%	96.956	1.53%
2012	97.477	0.60%	96.375	-0.60%
2013	98.085	0.62%	97.286	0.94%
2014	98.665	0.59%	99.098	1.85%
2015	99.456	0.80%	98.316	-0.79%
2016	99.389	-0.07%	98.493	0.18%
2017	100.000	0.61%	100.000	1.52%
2018	100.702	0.70%	99.943	-0.06%
2019	101.959	1.24%	99.625	-0.32%
2020	101.635	-0.32%	100.852	1.22%
2021	105.027	3.28%	98.664	-2.19%
2022	103.243	-1.71%	99.290	0.63%

Annual Average Growth Rates

		U.S.	Canada
2003-2022	20 years	**0.73%**	**-0.14%**
2008-2022	15 years	**0.53%**	**0.00%**
2013-2022	10 years	**0.57%**	**0.30%**
2018-2022	5 years	**0.64%**	**-0.14%**

Sources:

Bureau of Labor Statistics (Series MPU4900012) and
Statistics Canada (Table: 36-10-0208-01)

g) A properly calibrated inflation factor is desirable in an indexed ARM because it mirrors competitive markets and reduces utility risk without weakening utility performance incentives. In the United States, this is chiefly a matter of doing something about the brisk MFP trend of the U.S. economy. Calculation of an input price differential is much more complicated and controversial.

h) PEG was interested in input price indexes that were specific to the Toronto metro area and asked an IR on this matter.[1] However, we did not find any useful data on this matter. We note that Clearspring did not use any Toronto-specific inflation measures in its benchmarking research for THESL, nor did Toronto Hydro propose any Toronto-specific indexes for its inflation factor formula.

i) PEG considers this request to be onerous. We have reported on the TFP trend of U.S. power distributors in this and two other recent proceedings. The study for Hawaiian Electric was limited to a sample of 45 vertically-integrated electric utilities, which is only slightly more than half of the 87 distributors that comprised PEG's power distributor TFP sample in this proceeding.

j) The TFP growth of U.S. power distributors has slowed in recent years and repex is plausibly one of the reasons. This growth slowdown would contribute to negative VIEU productivity growth even if the TFP trend of power distributors was positive. The negative TFP finding in the HECO proceeding was due in part to the well-established negative productivity trend of U.S. power transmitters. PEG periodically measures the TFP trend of U.S. power distributors and has never found it to be negative, unlike competing consultancies such as the Brattle Group and Christensen Associates that do most of their work for utilities.

[1] 1B-Staff-27.

M3-TH-003

Reference: PEG Clearspring Report, p. 31, "The following methods that we used in model development differed from Clearspring's."

In EB-2021-0110, Hydro One's most recent rate application, PEG and Clearspring issued a Joint Report in June 2022. In that report, PEG produced a total cost benchmarking model and reported distribution total cost benchmarking results that were very similar to Clearspring's. In the current case, Clearspring continued the benchmarking progress made in that conferral process and Joint Report by retaining all the methodologies agreed upon and only added two variables and refined the percent congested urban variable that both Clearspring and PEG put in their models for all CIR benchmarking research including the last Toronto Hydro application and both consultants agreed should be included in the model. Unlike Clearspring, PEG has now made several significant departures in methodology and the variables included within the models from that conferral process.

Interrogatories

a) Please separately list all variable differences and other methodological differences between PEG's Joint Report total cost benchmarking study and PEG's research in the current study.

b) Did PEG produce and examine model runs that replicated the Joint Report model specification during the course of its research in this application?

c) Please provide the Toronto Hydro benchmarking results using PEG's model specification used by PEG in the Hydro One Joint Report.

d) Did PEG translog the service territory area in its Joint Report study?

e) Did PEG produce and examine model runs with the area variables translogged in the model during the course of its research in this application?

f) Please provide the Toronto Hydro results if the area variables are translogged with all other variables and methodologies remaining the same. For the area congested urban variable, interact it with the other output variables and take a quadratic without taking the natural log since many of the observations are zero and cannot be logged.

g) Please confirm that PEG treated the total service area as a scale or output variable in its Joint Report study.

h) Please provide the Toronto Hydro results if the two area variables in PEG's model are replaced with the percent congested urban variable and the total area variable used by PEG in its Joint Report with all other variables and methodologies remaining the same.

i) Please confirm that PEG has modified its sample period start year from 2002 in the Joint Report to 2007.

j) Did PEG examine model runs with the 2002 start year used by PEG in the Joint Report and/or any other start years during the course of its research? If so, please list the start years examined by PEG.

k) Please provide the PEG model results if PEG moved the start year to 2002 as it used in the Joint Report with all other variables and methodologies remaining the same.

l) Please confirm that PEG has changed the forestation variable from being interacted with overhead in the Joint Report to now being a standalone variable.

m) Please provide the PEG Toronto Hydro results if PEG used the same forestation and overhead variable as it used in the Joint Report with all other variables and methodologies remaining the same.

n) Please confirm that PEG changed how it constructed the percent overhead variable relative to its treatment of it in the Joint Report.

o) Please confirm PEG uses a different standard error correction in the current research relative to what it used in the Joint Report.

p) Does PEG believe that a distribution substation count variable and/or a capacity variable is sensible and would potentially improve the model assuming the data was not problematic?

q) Did PEG produce and examine model runs with these variables in the model during the course of its research?

r) Please include the two substation variables in PEG's model and report the Toronto Hydro results with all other variables and methodologies remaining the same.

Responses:

The following responses were provided by PEG.

a) This model has two additional years of data and a different subject utility, and it would be poor practice to fail to make reasonable updates based on new information. There are two categories to the differences in PEG's models:

   1. Formal changes from the Joint Report:

      i. We translogged the area variable term after first presenting a model using an alternative measure. Because our preferred measure was contested, there were other issues which were much more important to address, and because the model did not hinge upon it, PEG did use this specification with major adjustments to the subject company's Clearspring-assigned area value.

      ii. We used Clearspring's "distribution work" variable. It performed acceptably when we tested Clearspring's model specification and so we did not exclude it.

2. Minor changes from the Joint Report based on econometric model tests and refinements.

   i. In our models for Toronto Hydro, we used Clearspring's 10-year rolling average of peak demand variable instead of the ratcheted peak variable we used in the Joint Report. We tested both measures in this model and when developing the Joint Report model, Clearspring's version had more statistical support in this particular model. Peak demand is a clear cost driver and we do not view this as a major methodological change. Our use of ratcheted peak in the Joint Report was appropriate, and the measure could validly be used in this model and in future models.

   ii. We upgraded the "percent overhead" variable to match its definition, rather than stay with the "percent of distribution plant which is not the two underground accounts" calculation. This is a variable refinement. Please see PEG's answer to M3-TH-15, part n) for more information.

   iii. We used the percent overhead and percent forested interaction variable, calculated by multiplying the two variables and then logging the product, in our total cost model. We also used the logged percent overhead variable alone and alongside the interaction term in our Joint Report OM&A and capital cost models. We note that Clearspring appears to have changed their methodology for calculating this variable since the Joint Report but has not identified this.

   iv. We used Clearspring's percent congested urban variable, as the variable construction was not so distortionary as it is in Clearspring's model for Toronto Hydro. We do not disagree that urban challenges should be modeled if possible. We have raised concerns about this variable in other proceedings, but have not been able to create a variable which addresses its deficiencies. We used it in the Joint

Report model as it functioned acceptably and addressing the finer points of it was not a priority since the subject utility did not receive a materially different benchmark for the same variable as is the case in this proceeding. In addition, splitting the area variable in that model would be much less desirable since that version was time-invariant.

v. We tested the elevation variable, but it was not statistically significant in these models and thus was not providing helpful or additional information. We do not consider this a methodological change.

vi. We excluded the Joint Report plant-based scope variable from the OM&A model because it was no longer significant.

b) No. PEG has continued developing and improving its methods and econometric models since issuing the Joint Report in June of 2022, which had a sample data end date of 2019.

c) PEG declines to undertake the requested work. The time and budget available to respond to Clearspring's numerous IRs is limited and Clearspring is capable of doing many of the runs that it requests. PEG also recalls the disinclination of Clearspring to do alternative runs in response to IRs of Board Staff.

d) Yes. Please note, however, that a number of other issues were central to the recent Hydro One proceeding, which in addition to distribution cost benchmarking, encompassed transmission benchmarking and productivity measurement. The optimality of some modelling practices was as a consequence not considered. For example, in EB-2021-0110 Exhibit N/Tab 1/Schedule 21 PEG said, within many paragraphs of discussion of issues specific to Hydro One Networks, "The optimality of area as a scale measure was not considered."

e) Yes, we started from Clearspring's specification and made changes to the model based on either:

i. PEG's continued research and model development experience including and beyond that obtained from the Joint Report, or

ii. Identifying major problems with Clearspring's model specification and eliminating or correcting those problems if possible.

Changing the area variable specification away from translog treatment was a result of both i. and ii., but especially ii. given the ~33% occurrence of negative output elasticities produced by the area term in Clearspring's model.

f) Please see our response to M3-TH-003, part d).

g) This statement is confirmed. For more context please see the answer to the question in part d) above.

h) Please see the response to M3-TH-014.

i) This statement is confirmed. A major reason why this step was taken was to make the trend variable parameter estimate more relevant in determining the base cost efficiency trend. We did not focus on differences in benchmarking results for THESL.

j) Yes. PEG started with Clearspring's 2000 start date in accordance with our process described in part e) of this question. 2007 was the only other time period considered or tested.

k) Results for the models with the longer sample period are below. These models are based on PEG's corrected models found in our response to M3-TH-025, part a).

PEG Model of Total Distributor Cost 2002-2021

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTELEC =	Percent Electric Customers
PCTAMI =	Percent AMI
PCTODXG =	Percent Distribution O&M of Transmission, Distribution, and Generation O&M
FOR =	Percent Forestation in Service Territory
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.438***	67.770	0.000
D	0.512***	70.617	0.000
N*N	0.689***	7.145	0.000
D*D	1.103***	11.681	0.000
N*D	-0.887***	-9.189	0.000
AREACU	0.0212***	32.031	0.000
AREAOTHER	0.0471***	16.273	0.000
PCTELEC	0.103***	5.464	0.000
PCTAMI	0.0102***	4.468	0.000
PCTODXG	0.0912***	13.673	0.000
FOR	0.0451***	22.660	0.000
DXWORK	0.164***	8.799	0.000
TREND	-0.00417**	-3.219	0.001
CONSTANT	13.13***	948.888	0.000

Adjusted R^2	0.974
Sample Period	2002-2021
Number of Observations	1,515

PEG Model of Distributor Capital Cost 2002-2021

VARIABLE KEY

N=	Number of Customers
D=	10-Year Rolling Avg of Distribution Peak
N*N=	Number of Customers squared
D*D=	Distribution Peak squared
N*D=	Number of Customers squared
AREACU=	Area Congested Urban
AREAOTHER=	Area Not Congested Urban
PCTOHL=	% of Line Plant OH
PCTELEC=	% Electric Customers
PCTAMI=	%AMI
DXWORK=	% Distribution Lines Over 50 kV
TREND=	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.492***	55.649	0.000
D	0.502***	68.911	0.000
N*N	0.382***	8.264	0.000
D*D	0.681***	16.261	0.000
N*D	-0.524***	-12.202	0.000
AREACU	0.0200***	8.453	0.000
AREAOTHER	0.0322***	13.084	0.000
PCTOHL	-0.0684**	-2.865	0.004
PCTELEC	0.121***	5.970	0.000
PCTAMI	0.0182***	16.240	0.000
DXWORK	0.124***	6.807	0.000
TREND	-0.00268**	-2.650	0.008
CONSTANT	10.62***	839.533	0.000

Adjusted R^2	0.970
Sample Period	2002-2021
Number of Observations	1,515

PEG Model of Distributor OM&A Cost 2002-2021

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTOHL =	% of Line Plant OH
DXCSI =	Distribution Construction Standards Index
FOR =	Percent Forestation in Service Territory
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.569***	27.482	0.000
D	0.348***	18.226	0.000
N*N	1.158***	3.758	0.000
D*D	1.571***	5.388	0.000
N*D	-1.349***	-4.513	0.000
AREACU	0.0326***	9.640	0.000
AREAOTHER	0.0524***	8.243	0.000
PCTOHL	0.406***	8.006	0.000
DXCSI	0.403***	9.393	0.000
FOR	0.0648***	9.209	0.000
DXWORK	0.116*	2.345	0.019
TREND	-0.00798***	-6.887	0.000
CONSTANT	11.98***	831.021	0.000

Adjusted R^2	0.897
Sample Period	2002-2021
Number of Observations	1,515

Year-by-Year Distributor Cost Benchmarking Results

Year	Total Cost Benchmark Score	Capital Cost Benchmark Score	OM&A Cost Benchmark Score
	[Actual - Predicted Cost]		
2007	-29.70%	-24.36%	-14.78%
2008	-26.29%	-20.41%	-13.49%
2009	-23.80%	-19.14%	-8.41%
2010	-16.65%	-15.30%	6.79%
2011	-10.14%	-8.45%	12.17%
2012	-11.11%	-8.34%	8.05%
2013	-6.23%	-4.47%	14.41%
2014	-2.59%	0.96%	12.69%
2015	0.00%	5.37%	8.06%
2016	5.43%	12.29%	7.97%
2017	9.34%	16.98%	8.46%
2018	11.46%	18.24%	12.98%
2019	13.65%	20.08%	15.91%
2020	14.09%	21.75%	12.47%
2021	16.83%	23.73%	17.07%
2022	18.88%	26.89%	15.08%
2023	22.51%	29.79%	20.41%
2024	24.30%	31.15%	23.25%
2025	26.55%	33.29%	25.38%
2026	29.01%	35.94%	26.58%
2027	31.06%	38.60%	26.10%
2028	33.31%	41.11%	26.87%
2029	35.72%	44.05%	26.90%
Averages			
2020-2022	**16.60%**	**24.12%**	**14.87%**
Forecast Period 2023-2029	***28.92%***	***36.28%***	***25.07%***
CIR Period 2025-2029	***31.13%***	***38.60%***	***26.37%***

Notes

Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

l) This statement is confirmed. The interaction term did not have statistical significance using the refined variable definition. Since the two components of the variable are theoretically solid, PEG tested them individually and used them as appropriate in each model.

m) Results are shown below. These models are based on PEG's corrected models found in our response to M3-TH-025, part a). It can be seen that Toronto Hydro's scores for the forecast period decline in the Total Cost and OM&A models. Please note that the specification PEG used in the Joint Report, which is to multiply overhead and forestation and then to log the product, is different from Clearspring's specification in their report for Toronto Hydro. Furthermore, PEG used the overhead variable both interacted and alone depending on the model. Please see PEG's answer to M3-TH-15, part i) for a more detailed discussion.

PEG Model of Total Distributor Cost Using % Distribution Plant Not Underground & Forestation Interaction Term

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTOH*PFOR =	%Plant not UG times %Forested
PCTELEC =	Percent Electric Customers
PCTAMI =	Percent AMI
PCTODXG =	Percent Distribution O&M of Transmission, Distribution, and Generation O&M
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.423***	53.287	0.000
D	0.533***	62.065	0.000
N*N	0.672***	5.740	0.000
D*D	1.112***	10.080	0.000
N*D	-0.877***	-7.573	0.000
AREACU	0.0233***	28.795	0.000
AREAOTHER	0.0420***	23.281	0.000
PCTOH*PFOR	0.0466***	25.029	0.000
PCTELEC	0.0718***	4.871	0.000
PCTAMI	0.0136***	3.582	0.000
PCTODXG	0.0892***	11.626	0.000
DXWORK	0.181***	8.546	0.000
TREND	-0.0023	-1.651	0.099
CONSTANT	13.11***	982.986	0.000

Adjusted R^2	0.972
Sample Period	2007-2021
Number of Observations	1,143

PEG Model of Distributor OM&A Cost Using % Distribution Plant Not Underground & Forestation Interaction Term with % Distribution Plant Not Underground

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTOH =	% of Distribution Plant not UG
PCTOH*PFOR =	%Plant not UG times %Forested
DXCSI =	Distribution Construction Standards Index
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.558***	22.063	0.000
D	0.376***	16.324	0.000
N*N	1.143**	3.210	0.001
D*D	1.619***	4.950	0.000
N*D	-1.350***	-3.952	0.000
AREACU	0.0318***	7.032	0.000
AREAOTHER	0.0345***	6.135	0.000
PCTOH	0.766***	7.619	0.000
PCTOH*PFOR	0.0747***	14.211	0.000
DXCSI	0.472***	13.314	0.000
DXWORK	0.158**	3.162	0.002
TREND	-0.00589***	-3.692	0.000
CONSTANT	11.97***	672.735	0.000

Adjusted R^2	0.884
Sample Period	2007-2021
Number of Observations	1,143

PEG Model of Distributor Capital Cost Using % Distribution Plant Not Underground

VARIABLE KEY

N=	Number of Customers
D=	10-Year Rolling Avg of Distribution Peak
N*N=	Number of Customers squared
D*D=	Distribution Peak squared
N*D=	Number of Customers squared
AREACU=	Area Congested Urban
AREAOTHER=	Area Not Congested Urban
PCTOH=	% of Distribution Plant not UG
PCTELEC=	% Electric Customers
PCTAMI=	%AMI
DXWORK=	% Distribution Lines Over 50 kV
TREND=	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.473***	48.132	0.000
D	0.523***	69.980	0.000
N*N	0.357***	5.284	0.000
D*D	0.686***	12.612	0.000
N*D	-0.510***	-8.446	0.000
AREACU	0.0238***	7.518	0.000
AREAOTHER	0.0299***	11.254	0.000
PCTOH	-0.078	-1.436	0.151
PCTELEC	0.0954***	5.068	0.000
PCTAMI	0.0239***	17.670	0.000
DXWORK	0.126***	5.529	0.000
TREND	-0.000844	-0.644	0.519
CONSTANT	10.59***	550.166	0.000

Adjusted R^2	0.969
Sample Period	2007-2021
Number of Observations	1,143

Year-by-Year Distributor Cost Benchmarking Results Using Joint Report Overheading & Forestation Specifications

Year	Total Cost Benchmark Score	Capital Cost Benchmark Score	OM&A Cost Benchmark Score
	[Actual - Predicted Cost]		
2007	-25.19%	-20.97%	-4.95%
2008	-21.93%	-17.08%	-4.40%
2009	-19.61%	-15.92%	0.10%
2010	-12.63%	-12.28%	15.24%
2011	-6.27%	-5.65%	20.73%
2012	-7.41%	-5.74%	16.66%
2013	-2.67%	-2.21%	24.01%
2014	0.76%	3.01%	21.83%
2015	3.20%	6.88%	19.23%
2016	8.37%	13.60%	18.05%
2017	12.03%	18.21%	17.08%
2018	13.95%	19.35%	20.75%
2019	15.98%	21.05%	23.37%
2020	16.30%	22.59%	19.94%
2021	18.91%	24.42%	24.65%
2022	20.82%	27.41%	22.75%
2023	*24.26%*	*30.08%*	*27.91%*
2024	*25.85%*	*31.18%*	*30.59%*
2025	*27.91%*	*33.08%*	*32.56%*
2026	*30.17%*	*35.47%*	*33.61%*
2027	*32.03%*	*37.87%*	*32.98%*
2028	*34.08%*	*40.12%*	*33.60%*
2029	*36.29%*	*42.79%*	*33.49%*
Averages			
2020-2022	**18.68%**	**24.81%**	**22.45%**
Forecast Period 2023-2029	***30.08%***	***35.80%***	***32.11%***
CIR Period 2025-2029	***32.10%***	***37.87%***	***33.25%***

Notes

Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

n) This statement is confirmed.

o) This is partially confirmed. PEG used the Driscoll-Kraay standard error correction procedure in both studies, but this time used the “fixed-b” adjustment to select the critical values based on the characteristics of the actual sample used. This method is an empirically established improvement over the previous method for the type of datasets used in this proceeding.

p) Yes, network variables would be desirable, if not in the format Clearspring selected in its model. PEG used MVA per substation and substations per customer or transmission line mile in our two previous Transmission models.

q) Yes, PEG produced initial runs with Clearspring’s specifications. After investigating the variables, we found them definitively unacceptable for econometric modeling.

r) PEG declines to perform this run, which is similar to runs that Clearspring declined to do in its IR responses, and which Clearspring can easily do. The substation data are very clearly flawed and inappropriate to include in these econometric models. They will by definition be biased, prone to spurious correlation, and it is unknown what effects they would actually be capturing other than patterns of reporting style on a partially free-form report.

M3-TH-004

Reference: PEG Clearspring Report, p. 5 “CIR proceedings are opportunities for Ontario’s regulatory community to reconsider how statistical cost research should be used in energy rate regulation.”

PEG produced a study of the U.S. TFP trend and put forth a new productivity factor (“PF”) that differs from the decided upon productivity factor in the 4th Generation IR generic proceeding and that differs from the 0.00% PF used in all other CIR applications.

Interrogatories

a) Is PEG of the view that an input price differential is a key component of calibrating an appropriate X-Factor in a multi-year revenue plan?

b) Did PEG examine what the appropriate input price differential should be in the case of a utility serving Toronto? If yes, please provide any study details and findings. If no, please explain why the component was not examined.

c) In PEG’s view, is it possible and/or likely that the City of Toronto has had or will have higher input price inflation than what the OEB calculated inflation factor measures?

d) If input price inflation for Toronto Hydro is higher than the OEB calculated inflation factor, in PEG’s view, should this lower the X-factor accordingly?

e) Would PEG be of the view that the input price inflation factor and/or an input price differential should be part of a fuller investigation of incentive regulation conducted by the OEB for the distributors in the Province?

Responses:

The following responses were provided by PEG.

a) PEG notes that an inflation differential is potentially important in a proceeding to design an indexed ARM. In proceedings where the inflation differential is an issue, it is often decomposed into a productivity differential and an input price differential as discussed in Section 5 of PEG's empirical report (Exhibit M3). Both differentials have typically been considered in recent proceedings. The matter of the input price differential is especially complex, most notably because it requires a measure of the capital price trend. In many proceedings, the capital price index is measured using a capital service price index like those used in benchmarking and productivity studies. These indexes are volatile and difficult for parties to understand because they do not measure the capital price inflation that is implicit in regulatory accounting.

The consideration of an input price differential materially complicates X factor research in IR proceedings and has been a source of unwelcome controversy. PEG accordingly believes that this issue should be explored only where exploration is warranted by circumstances. Other changes to input price indexes are easier to consider and PEG has proposed some in this proceeding.

b) As mentioned in our response to question M3-TH-002, part f) above, PEG did examine the multifactor productivity trend of Canada's economy. We have in prior Canadian proceedings taken a quick look at the Canadian inflation differential issue and found that it did not warrant further work.

c) Toronto's input price inflation could be faster or slower than that of the inflation measure that the OEB uses.

d) An adjustment to the rate or revenue cap index formula could be warranted if it could be convincingly demonstrated at reasonable cost that the City of Toronto's input price trend was more rapid than the OEB's inflation factor. It would not necessarily take the form of an X factor adjustment.

e) PEG again notes that an input price differential is not typically considered separately from a productivity differential. Investigating these matters is a judgement call inasmuch as some of the big reasons to undertake this work are absent in Ontario. The MFP trend of Canada's economy is zero or negative, and the OEB's inflation factor formula includes a local labor price index. This was not an issue in recent IR proceedings in Alberta and Québec.

M3-TH-005

Reference: PEG Clearspring Report, p. 7 "Clearspring's modified congested urban variable is overly sensitive to observations for a handful of urban utilities. The variable has other flaws that reduce its suitability, one of which is Clearspring's choice to use a 2012-2022 average growth in the number of Toronto skyscrapers to forecast a 7.1% annual growth rate in the congested urban area. Alternative and sensible treatments of the urban congestion challenge also receive strong statistical support but yield far less favorable benchmarking results for THESL."

Interrogatories

a) Please confirm that PEG used the time invariant percentage congested urban variable in its cost benchmarking research in the prior Toronto Hydro application, the last Hydro Ottawa application, and the last Hydro One application.

b) Please confirm that PEG applied Clearspring's methodology unchanged in escalating the congested urban area in PEG's new congested urban area variable.

c) In 2021, Commonwealth Edison and Pacific Gas & Electric have more congested urban area than Toronto Hydro (over 13 square km). Yet both utilities serve huge suburban and rural areas that encompass large parts of the state of Illinois and California. Does PEG consider that Commonwealth Edison and Pacific Gas and Electric have higher urban characteristics than Toronto Hydro?

d) Please confirm that PEG's model assumes that if Commonwealth Edison increased its congested urban area by one and Toronto Hydro increased its congested urban area by one square km, PEG's model would assume the same percentage increase in total costs for both utilities (2.67%).

e) Please confirm that since Commonwealth Edison has total costs around triple that of Toronto Hydro, that adding one sq. km of congested urban would, therefore, add triple the total costs to Commonwealth Edison than it would to Toronto Hydro.

Responses:

The following responses were provided by PEG.

a) This statement is confirmed. However, PEG believes that the modelling of urban congestion deserves a fresh look in this proceeding for several reasons.

- Clearspring introduced a time-variant version of the percent CU variable that has a major impact on benchmarking results.
- The construction of this variable is controversial for various reasons, some of which are discussed in PEG's empirical report.
- In contrast to the recent Hydro One proceeding, the treatment of urban congestion matters greatly in a THESL cost benchmarking study.

b) This statement is confirmed. Clearspring's congested urban area estimates were not ideal but upgrading these estimates was not a PEG priority with limited time and budget. Using Clearspring's variable, with its aggressive growth for THESL during the sample period, reduces concern that our benchmarking work is insensitive to THESL's cost challenges.

c) PG&E and Commonwealth Edison face larger urban congestion challenges than THESL and also larger challenges in serving other areas. PEG's specification takes into account both the challenges of serving a large congested urban area and the challenges of serving other areas.

d) PEG acknowledges that the cost impact of adding one km of congested urban area would be the same for Com Ed and Toronto Hydro. However, the *elasticity* of cost with respect to congested urban area does vary by company and THESL has one of the highest values in the sample. PEG disputes the contention that adding 1 square km of area adds 2.67% to cost. The value using our corrected total cost model is somewhat lower. Please see the response to M3-TH-17, part a). We believe that our model provides a more plausible treatment of the cost impact of growth in urban congestion than Clearspring's.

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

<u>M3-TH-006</u>

Reference: PEG Clearspring Report, p. 7 “The area variable should not be translogged...”

Interrogatories

a) Please confirm that PEG translogged the area variable in its own total cost model in the Hydro One Joint Report.

b) Please confirm that PEG did not raise any concerns in the Joint Report regarding translogging the area variable.

Responses:

The following responses were provided by PEG.

a) Please see PEG’s response to question M3-TH-3, part d).

b) This statement is confirmed. Please see the response to question M3-TH-3, part d) for explanation.

M3-TH-007

Reference*:* PEG Clearspring Report, p. 7 "The substation and substation capacity data used in the study were extensively flawed."

Interrogatories

a) Please confirm that PEG included substation variables in its transmission total cost model in the Hydro One Joint Report.

b) Did PEG conduct a similar analysis of the data issues of its own substation variables in its transmission total cost research? If so, please provide the analysis and findings. If not, why not?

c) Does PEG believe that a substation and/or a substation capacity variable has merit assuming data issues are not a concern?

Responses:

The following responses were provided by PEG.

a) This statement is confirmed. PEG took the time to produce good substation and MVA variables --- for transmission only ---, for the years 2004, 2009, and 2019.

Undertaking this process accurately was time-consuming and detailed. PEG described our process for obtaining the 2009 and 2019 values as follows:

> "*PEG first cleaned the data with programmatic rules, then hand-checked and corrected the values after discovering programmatic cleaning still missed some major problems.*
>
> *The Form 1 substation data require extensive cleaning and PEG did not have the time or budget to complete a full time-series. Since mismeasurement bias is a problem in econometric modeling, PEG opted to obtain two accurate points and then interpolate values between them in order to capture both the level and overall growth."*

PEG was willing to do the work on the transmission side for several reasons.

- Transmission costs are more difficult to model accurately (e.g., lower R-squared statistics) relative to distribution.
- There were fewer companies in the transmission research and fewer substations to consider.
- There is an issue on the transmission side of whether the transmission company owns generation substations that has no counterpart on the distribution side.
- In a prior study, we had already calculated two years' worth of substation data in a study on the cost efficiency of Hydro-Québec Transmission. Determining whether Hydro-Québec played an outsized role in substation work was a concern in that proceeding.

Even the partially-processed distribution substation data from the transmission years would have necessitated a significant additional amount of work for not enough benefit to the distribution cost model.

b) No formal analysis of our data was needed because we addressed whatever issues arose during the construction of the variable. We found the substation data processing to be extremely complicated and have not found it practical to undertake this work for every year for which data are available. This raised concerns that the Clearspring data could be flawed unless a very large amount of effort was expended to create values for all years. We asked about this in a data request to provide an opportunity for Clearspring to address any issues similar to those that we encountered in our transmission research. When no changes were forthcoming from Clearspring we did a quick examination of their data to check for any double counting or other concerns. What we found was enough to warrant a question during the technical conference to afford Clearspring another opportunity to address any issues. We concluded that the data provided did not meet our standards and decided to exclude the substation variables from the analysis.

Using our own data for this work was not a reasonable option for several reasons including budget and time constraints. The construction of distribution substation variables would have resulted in only a single year of data and involved a lot of work for little value relative to other methodological improvements.

c) The answer here is maybe. Network variables are desirable in cost benchmarking to the extent that they reflect important external cost drivers that are otherwise absent from the model. A line length variable can, for example, proxy for system extensiveness. The downside of a network variable is that its values can be to some degree endogenous and thereby violate an assumption on which econometric research is based. In the case of substation capacity this is a particular concern in power distribution going forward when containment of capacity costs will be a key issue. It will be best not to treat this capacity as exogenous.

<u>M3-TH-008</u>

Reference: PEG Clearspring Report, p. 9 “The OEB has not authorized a new study of Ontario productivity trends in more than a decade. The latest U.S. evidence suggests that a small base cost efficiency growth factor of 0.10% is reasonable for both the OM&A and capital revenue of THESL.”

Interrogatories

a) Is PEG of the view that a new study of Ontario productivity trends would be helpful in determining the appropriate productivity factor for Ontario distributors?

b) Is PEG’s recommendation of a 0.10% efficiency factor based on its finding that the ten-year cost-weighted TFP growth for the U.S. industry of 0.10%?

c) What is the difference in how PEG is using the definitions between an “efficiency growth factor” and the “productivity factor”?

d) Would PEG characterize Toronto Hydro as being a “medium” utility relative to PEG’s TFP dataset? Please provide a comparison to the sample average of how Toronto Hydro compares in terms of the components of TFP trends which are the number of customers served, peak demand, capital quantity, and OM&A quantity.

e) Would PEG be of the view that it would be a reasonable alternative to use the average-weighted TFP trends as the basis for the cost efficiency trend?

f) Please confirm that PEG in its 4th Generation IR productivity research threw out the two largest distributors from the calculations because of the large impact they had on the industry TFP trend in Ontario.

g) Is PEG of the view that the Ontario TFP trend may be informative and useful in a proper investigation of revising a new productivity factor?

h) Has PEG conducted research on the recent Ontario TFP trend within the last ten years? If so, please provide the results and analysis.

i) Please confirm that PEG has not provided U.S. TFP trend research in prior electric distribution CIR applications. If not confirmed, please provide.

j) Is PEG of the view that in the case of a negative TFP trend in the industry, a negative productivity factor would be the theoretically correct approach? Would PEG ever support a negative productivity factor? If not, please explain the rationale.

Responses:

The following responses were provided by PEG.

a) Yes. However, the OEB has not regarded a reconsideration of this matter as a priority for over a decade. Furthermore, we believe that U.S. power distributor productivity trends are more relevant in calibrating the X factor for Toronto Hydro. Please note also that the OEB chose to use only the TFP trend of Ontario distributors to set 4th GIRM X factors even though U.S. productivity trends would also have been informative. It made a decision in the absence of some relevant information.

b) PEG's recommendation is based on consideration of multiple results on cost efficiency trends. We chose a number that was linked to a specific study outcome that was in the range of reasonableness. It is very similar to the number yielded using an even-weighted average over 15 years.

c) PEG prefers the term "cost efficiency" factor to the term "productivity factor" because the base cost efficiency trend need not be determined by a productivity study. It could alternatively be determined by an econometric cost study.

d) Yes. PEG only considered operating scale when making this statement. The other referenced variables are not exogenous. We decline to calculate the quantities in view of our limited time and budget.

e) Yes. The even-weighted average of productivity trends is also relevant and this is discussed in PEG's empirical report. However, a size-weighted average of the productivity trends of Ontario distributors was implicitly used in the RRFE proceeding.

f) The statement is confirmed. Toronto Hydro is an atypical Ontario utility and due to its large relative size, a productivity trend based on a peer group that included THESL might be inappropriate to apply to THESL or to the many small distributors in Ontario.

g) Please see the response to part a) of this question.

h) PEG has not been authorized by the OEB and has not undertaken a rigorous and thorough study of Ontario productivity trends in more than a decade.

i) This statement is confirmed. PEG did, however, present results of research on U.S. productivity trends in prior OEB proceedings.[2] What tipped the scales in favor of a new productivity study in this proceeding was the following.

    1. PEG undertook a US productivity trend study just last year and was willing to update it to include 2022 data for free.[3]
    2. THESL has made the unusual contention that it is no longer possible to operate under an indexed ARM for its OM&A revenue. This raises the question as to whether OM&A productivity growth in the States has turned negative.

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[2] See, for example, Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A. (2008), "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario: Report to the Ontario Energy Board", February 2008, filed in Ontario Energy Board Case Number EB-2007-0673). For a gas example, see Lowry, M.N. (2018), "IRM Framework for the Proposed Merger of Enbridge and Union Gas", Revised May 4, filed in Ontario Energy Board Case Numbers EB-2017-0306/EB-2017-0307. PEG has also filed testimony on U.S. power transmitter TFP trends on multiple occasions and U.S. hydroelectric generation TFP trends once.

[3] This study used a definition of OM&A expenses that would be inapplicable to THESL.

j) PEG has reported negative TFP trends in several proceedings and has recommended their use in setting X factors. Several instances where PEG found negative TFP trends and recommended their use in X factor calibration are listed in Attachment N3-TH-1a.

M3-TH-009

Reference: PEG Clearspring Report, p. 24 “Table 1 and Figure 5 below illustrate how various reasonable changes to Clearspring’s skyscraper growth assumption affect THESL’s forecast cost performance scores.”

Interrogatories

a) What assumption between the six changes displayed did PEG make for its new congested urban area variable?

b) Is PEG of the view that a 0.28% growth rate in 2027 and a 0% growth rate in 2028 skyscrapers in Toronto is reasonable? Please explain.

c) Is PEG of the view that skyscrapers in Toronto in 2023 increased by only 1.19%? Please explain.

d) Does PEG agree that Toronto is one of the fastest growing cities in North America? If not, please explain.

e) Does PEG agree that the congested urban cost challenge for Toronto Hydro is growing every year and that growth should be reflected in a time variant congested urban variable?

Responses:

The following responses were provided by PEG.

a) PEG used the same treatment as Clearspring, considering that an upgrade to this variable was not a priority with limited time and budget.

b) PEG does not speculate on the likely progression of high rise construction in Toronto, affected as it is by various circumstances that include high interest rates and pandemic-induced changes in office building use. This is why PEG provided the results of multiple alternative assumptions based on past data.

c) Please see the answers to part a) and b) above. PEG does not claim to have data supporting one particular assumption, and so provided results using the data provided and alternative assumptions using historical data.

d) PEG noted on page 73 of its Framework report that Toronto was the 12th most rapidly growing major metro area in North America from 2017 to 2022 on a percentage basis.

e) PEG acknowledges that the challenges of serving a congested urban area are growing for Toronto. Creating a time-variant version of the variable can improve modelling if it can be done credibly and non-controversially.

M3-TH-010

Reference: PEG Clearspring Report, p. *25, Figure 5.*

Interrogatory

Please explain why the 2023-2029 growth assumption would impact the 2018 value such that the blue line in the graph is higher than the orange line in 2018, 2019, 2020, 2021, and 2022.

Response:

The following response was provided by PEG.

The blue line shows the results of Clearspring's model with what PEG considers to be the minimum level of corrections. PEG's graph setup shows the context of PEG's model corrections and the additional effects of Clearspring's congested urban variable skyscraper assumptions.

M3-TH-011

Reference: PEG Clearspring Report, p. 28 “Clearspring uses the Driscoll-Kraay standard error adjustment to their OLS model, but does not use the “Fixed-b” adjustment version.”

Interrogatory

Please confirm that PEG’s benchmark scores for Toronto Hydro would be the same if PEG did not use the “Fixed-b” adjustment but, instead used the Driscoll-Kraay estimator without the adjustment as Clearspring did and PEG did in the Hydro One Joint Report. Please provide a comparison of the T-statistics for the total cost model of the two approaches.

Response:

The following response was provided by PEG.

This statement is confirmed. The upgrade to the Driscoll-Kraay method that PEG used did not affect model parameter estimates. The intent was to upgrade hypothesis tests of the significance of these estimates.

Total Cost Model Variables			T-statistic	
	Variable	OLS Parameter Estimate	Driscoll-Kraay	Driscoll-Kraay with Fixed-b
N =	Number of Customers	0.423***	52.541	54.697
D =	10-Year Rolling Avg of Distribution Peak	0.532***	57.440	59.797
N*N =	Number of Customers squared	0.696***	5.810	6.049
D*D =	Distribution Peak squared	1.131***	9.835	10.239
N*D =	Number of Customers squared	-0.898***	-7.510	-7.818
AREACU =	Area Congested Urban	0.0215***	25.403	26.445
AREAOTHER =	Area Not Congested Urban	0.0428***	22.271	23.185
PCTELEC =	% of Line Plant OH	0.0792***	5.159	5.371
PCTAMI =	Percent AMI	0.0127***	3.255	3.389
PCTODXG =	Percent Distribution O&M of Transmission, Distribution, and Generation O&M	0.0899***	10.616	11.052
FOR =	Percent Forestation in Service Territory	0.0475***	31.458	32.749
DXWORK =	% Distribution Lines Over 50 kV	0.179***	8.142	8.476
TREND =	Time Trend	-0.00218	-1.515	-1.577
CONSTANT	Constant	13.11***	965.873	1005.514

M3-TH-012

Reference: PEG Clearspring Report, p. 29 “The Company’s customer count was meanwhile 0.77 times the mean while its rolling average ratcheted peak demand was 0.89 times the mean.”

On Table 5, PEG displays its total cost model and describes the peak demand variable as “10-Year Rolling Avg of Distribution Peak”. On p. 29 the peak demand is described as being ratcheted.

Interrogatory

a) Is PEG’s peak demand variable in its econometric total cost model ratcheted or is it a 10-Year rolling average of the annual system peaks? Please describe if its neither one of these options.

Response:

The following response was provided by PEG.

a) PEG used Clearspring’s 10-year rolling average of the annual system peaks. The reference to ratcheted peak was simply a labeling mistake. PEG has frequently used ratcheted peak demand in the past but found that the 10-year rolling average had more statistical support in this round of research.

M3-TH-013

Reference: PEG Clearspring Report, p. 29 “The TFP level result is clearly unfavorable to the Company”.

Interrogatories

a) Please confirm that PEG’s TFP level finding in 2021 does not account for the several cost challenges that PEG cites after this statement.

b) In PEG’s total cost model the share of overhead distribution assets has a negative parameter estimate, implying that the higher share of overhead the lower the costs are. Since PEG states that Toronto Hydro’s share is 0.42 times the mean, should this also be listed as a cost challenge rather than PEG implying in its report that it is a cost advantage for the Company?

Responses:

The following responses were provided by PEG.

a) This statement is confirmed. Productivity levels only control for differences in the input prices and operating scale of sampled utilities. The econometric benchmarking approach considers additional business conditions and PEG considers the econometric method superior for this and other reasons. The provision of productivity levels was a simple exercise that we have undertaken in many benchmarking studies in part to underline the desirability of considering additional variables. For 2021 the productivity level of THESL was low. Therefore, the Clearspring study was showing an enormous impact from the business conditions chosen and other factors that make the econometric results different from the productivity results. The PEG econometric work focused on evaluating the Clearspring model to find the sources of this large difference in results. In the end PEG found econometric results that did not differ as much from the productivity level as the Clearspring econometric results.

b) Yes. However, in the corrected total cost model provided in response to M3-TH-25, part a), this variable no longer appears because its parameter estimate was statistically insignificant.

M3-TH-014

Reference: PEG Clearspring Report, p. 31 “The Company’s service territory area outside of the urban core was a tiny 0.03 times the mean.”

Interrogatories

a) Would PEG consider Toronto Hydro to be an outlier in terms of this variable since its value is 0.03 times the mean?

b) Please list the possible variable or model specification alternatives to capturing network density that PEG considered when developing its total cost model.

Responses:

The following responses were provided by PEG.

a) Yes. Toronto Hydro is an outlier for the total service territory area outside of the urban core, in which it has just 3% of the mean of the sample service territory areas. It is also an outlier for its total area which is congested urban, for which its value is 607% of the sample mean.

b) Spurred by concerns about Clearspring’s modified CU variable, and the importance of the CU specification in a study for THESL, PEG has considered various alternative CU treatments in this proceeding. To facilitate an apples-to-apples comparison of results, we present in the table below a summary of key total cost model results for various runs that we considered where other model details are the same as in our featured run. All of the runs dispense with the translogging (i.e., the addition of quadratic and interaction terms) of the area variable.

   Inspecting the results, it can be seen that several of the alternative CU specifications generate appraisals of THESL’s total cost performance that are similar to those in PEG’s featured run. All of the runs produce appraisal’s of THESL’s cost performance that are much less favorable than Clearspring’s.

Table N3-TH-14b

Comparing Total Cost Model Results for Alternative CU Specifications

Option	Variable	Parameter Estimate	T-statistic	P-value	Average THESL Total Cost Benchmarking Scores	
					2020 to 2022	2025 to 2029
1	Area of Service Territory	0.0444	25.653	0.000	-13.6%	-8.7%
	Time-Variant Percent Congested Urban	0.0129	32.454	0.000		
2	Area of Service Territory	0.0433	29.398	0.000	-6.5%	11.0%
	Time-Invariant Percent Congested Urban	0.0118	11.479	0.000		
3	Area of Service Territory	0.0283	15.432	0.000	15.8%	32.9%
	Customer Density (Customers/Area)	0.0190	28.248	0.000		
	Customer Density Squared	0.0283	11.135	0.000		
4	Area of Service Territory	0.0412	21.605	0.000	16.8%	28.2%
	Number of Skyscrapers	0.0102	18.235	0.000		
5	Area Congested Urban	0.0215	26.445	0.000	17.3%	30.9%
	Area Not Congested Urban	0.0428	23.185	0.000		

M3-TH-015

Reference: PEG Clearspring Report, p. 31 "The following methods that we used in model development differed from Clearspring's."

After this statement, PEG then lists eleven differences from Clearspring's methods. Most of these also differed from the methods in the Hydro One Joint Report.

Interrogatories

a) Please confirm that PEG did treat service territory area as a scale variable and translogged it in the Joint Report.

b) Please confirm that PEG did not raise any concerns about treating service territory as a scale variable in the Joint Report.

c) Please confirm that mean-scaling all variables has no impact on the results.

d) Please confirm that PEG used a percentage congested urban variable in the Joint Report.

e) Please confirm that PEG did not raise any concerns about using a percent congested urban variable in the Joint Report.

f) Please confirm that PEG used a start year of 2002 in the Joint Report and not 2007.

g) Please confirm that PEG did not raise any concerns about the start year in the Joint Report.

h) Please confirm that PEG used an interaction variable of overhead x forestation in the Joint Report.

i) Please confirm that PEG did not raise any concerns about the interaction variable of overhead x forestation in the Joint Report.

j) Please confirm that PEG did not use a distribution construction standards index in its OM&A cost model in the Joint Report.

k) Please confirm that it was PEG that put forward the scope variable during the Joint Report conferral process but did not state that corrections should be made to the reported data.

l) Did PEG make these same corrections to its scope variable in the Joint Report that it made in this application?

m) Please confirm that PEG used Clearspring's overhead variable construction in the Joint Report.

n) Please confirm that PEG did not raise any concerns about Clearspring's overhead variable construction in the Joint Report.

o) Please confirm that PEG used the same estimation process of Driscoll-Kraay as Clearspring did in the Joint Report.

p) Please confirm that PEG did not raise any concerns about Clearspring's estimation process of using Driscoll-Kraay in the Joint Report.

q) Please confirm that PEG examined and made some corrections but then included substation variables in the Joint Report for transmission total cost benchmarking.

r) Please confirm that PEG did not raise any concerns about including substation variables in the transmission total cost model in the Joint Report.

s) Did PEG also change how the OM&A input price is constructed relative to its research in the Joint Report?

Responses:

The following responses were provided by PEG.

a) This is confirmed, but context may be helpful. Because of concerns about the area variable, PEG's originally-submitted model used the length of transmission lines to proxy for the service territory footprint. There were a number of other issues with the area variable in that proceeding for Hydro One Networks, including the fact that the value for the distributor's service territory area included vast remote areas which it is not responsible for. There were many other more important topics of contention so PEG did use the area variable in translog form with a major adjustment to HON's value.

b) This is partially confirmed. PEG did not use the service territory variable in its originally-submitted power distribution model. We did use it in the Joint Report, but clearly stated that "the optimality of area as a scale measure was not considered."

c) Meanscaling should have zero impact on the benchmarking results. However, Clearspring included Toronto Hydro's forecasted values in the calculation of the sample means for the scale variables, which is an error which introduces measurement bias. In this case, it is fortunate that Clearspring did not log the non-scale variables and thus avoided introducing additional bias into every variable. However, meanscaling is a best practice in econometric modeling of this type. An approach that facilitates clarity in model interpretation is preferred.

d) Please see our response to M3-TH-005, part a).

e) This is confirmed. However, the CU variable was not a key issue in a distributor cost benchmarking study for Hydro One. PEG was effectively trying to "keep Clearspring honest" by including a variable that favored urban utilities.

f) This statement is confirmed.

g) This statement is confirmed. PEG opted to use a shorter sample period than Clearspring in both our original and Joint Report models. This was an area of disagreement in which each party used their preferred sample period and it was not a central issue.

h) This statement is confirmed. PEG used an interaction term in our total cost model in the Joint Report, which was calculated by first multiplying the percent overhead and percent forested variables and then logging the resulting product. In the OM&A model, PEG used both the standalone logged percent overhead variable and the interaction term calculated as described in the sentence prior. In the capital cost model, PEG used only the logged percent overhead variable. At no point did PEG use the mixed level and log interaction procedure introduced by Clearspring in its model for Toronto Hydro.

i) PEG destroyed Clearspring's original working papers in accordance with the confidentiality agreement and Clearspring did not provide working papers for its Joint Report model. As a result, PEG cannot comment definitively on Clearspring's procedure for interacting the two variables in either of its models. We can definitely confirm that for both of PEG's models (original and Joint Report), we did not use Clearspring's current level-log interaction method. PEG's models were produced using Clearspring's data and modifying Clearspring's code, so it seems unlikely that we would not have sought clarification from Clearspring if they had used the level-log interaction procedure at that time.

   To answer the question posed with the appropriate context, it is confirmed that PEG did not raise concerns because Clearspring had interacted the variables in a more traditional manner in that model. In addition, PEG would note that we used both the standalone overhead line and the interaction terms as appropriate in each model. This is exactly what PEG has done with its model specification for Toronto Hydro; when the interaction term did not work we tested the components.

j) This is confirmed.

k) PEG developed the scope variable using our own dataset. PEG and Clearspring developed their own final models for the Joint Report and did not review each others' data or working papers beyond what had been exchanged as part of the original working paper filings. It is PEG's understanding that Clearspring relied upon purchased data from S&P Global for their variable calculations, while PEG gathered and processed the raw FERC Form 1 data needed for any additional variables. PEG had no way to be aware of potential issues in Clearspring's database from S&P or in Clearspring's data management processes. PEG's dataset did not contain values in excess of 100%.

l) PEG has reviewed our Excel dataset for our Joint Report model, and we have confirmed our calculated scope variable did not contain any values over 100%.

m) This statement is likely to be true. We have not found the time to confirm.

n) This statement is confirmed. Due to limited time and budget in a project spanning transmission and distribution research, PEG was not able to make every model improvement they would in an ideal world. Other issues were more important to address. PEG was able to add this refinement to the variable due to recent database updates made during our work in Alberta.

o) This statement is confirmed; PEG also uses OLS with Driscoll-Kraay standard errors in this report. The fixed-b method simply selects the appropriate critical value for the Driscoll-Kraay standard errors.

p) This is confirmed. Subsequent to the Joint Report PEG learned about – then researched and tested - an improvement to Driscoll-Kraay that was created to render it more suitable for this type of panel data. PEG now uses the fixed-b adjustment whenever using OLS with the Driscoll-Kraay standard error estimation procedure. PEG believe OLS is one of several estimation methods which can be appropriate for econometric cost benchmarking. PEG tested FGLS methods for these models as well, and they yield very similar results. To minimize unnecessary differences between the PEG's and Clearspring's models, we have used OLS with Driscoll-Kraay in proceedings where Clearspring is involved. The parameter estimates are completely unaffected by either Driscoll-Kraay or the fixed-b adjustment to it; this is simply a small, best-practice methodological upgrade.

q) The second half of the question is confirmed: PEG's substation data was used in both its original model and Joint Report model. PEG found several major errors in Clearspring's transmission substation variable which were documented at length in that proceeding. The first half of the question is not confirmed: No parties raised concerns about the quality of PEG's substation data, which PEG had thoroughly vetted and used in a transmission cost model in a Hydro-Québec Transmission IR proceeding. Thus, no corrections were requested, or needed, for PEG's variable. Please see the answer to question 7, part a) for further information about PEG's transmission substation variable development.

r) This question is worded confusingly as PEG did not raise concerns about the *idea* of including substation variables in transmission models. If the question is asking about PEG having raised concerns about Clearspring's substation variables, this is not confirmed. PEG raised concerns and provided several rounds of supporting evidence of substantial problems in Clearspring's data in the technical conference, in interrogatories, and in our report which included an appendix specific to the substation problems. In the Joint Report, Clearspring and PEG each developed their own models and we put our own results into the report. Neither party presented the model parameters in the intentionally concise and straightforward report. In response to interrogatories from other parties, both PEG and Clearspring presented their model parameters. Clearspring opted to use their substation variable in their own model and did not confer with PEG about this choice; all of PEG's documented criticisms of the variable stand.

s) Yes. Recent research for Puget Sound Energy alerted us to the desirability of upgrading the OM&A input price index.

M3-TH-016

Reference: PEG Clearspring Report, p. 32 “We added a distribution construction standards index variable developed by Power Systems Engineering to the OM&A cost model.”

Interrogatories

a) Did PEG attempt to include this variable in the total cost model?

b) Please provide the total cost results for Toronto Hydro of including this variable with no other variable or methods changed.

c) It would seem that a construction standards index should impact capital and total costs but have a lesser or no impact on OM&A costs. Why did PEG only include this variable in its OM&A model? On what theoretical basis is it included for OM&A but not total or capital cost?

d) Please provide details on the construction of this variable and how it was developed.

e) Did Power Systems Engineering develop this variable for PEG? Did PEG subcontract with Power Systems Engineering? If so, please provide the retainer or engagement agreement/confirmation with PSE and all written instructions provided to it.

Responses:

The following responses were provided by PEG.

a) PEG tried this variable in the total cost model at one stage in the research and its parameter estimate was not statistically significant.

b) Please see our response to M3-TH-003, part c).

c) The distribution construction standards index is calculated on the basis of variations in weather severity across North America. This makes this variable relevant to OM&A as well as capital costs.

d) This variable was developed by Power Systems Engineering ("PSE"). We used this variable with PSE's permission in our recent Alberta testimony. Details of the calculation of this variable are found in Attachment N3-TH-16d.

e) PEG has a cordial working relationship with PSE and previously paid PSE for the right to use this variable and to calculate values for four Alberta power distributors. There was no contract.

<u>M3-TH-017</u>

Reference: PEG Clearspring Report, p. 3*4, Table 5.*

Interrogatories

a) Does PEG have any engineering explanation for why its total cost model shows that the Area Not Congested Urban has a substantially higher parameter estimate than Area Congested Urban?

b) Please confirm that the parameter estimate for Area Not Congested Urban is approximately 57% higher than the parameter estimate for Area Congested Urban.

c) Would PEG agree with the statement that the percentage of total costs of Toronto Hydro driven by congested urban cost challenges is higher than nearly all other utilities in the sample with the possible exception of Consolidated Edison? If not, please explain why not.

d) Is PEG's congested area variable able to adjust for the fact that the percentage of congested urban costs relative to total costs varies dramatically by utility? For example, Consolidated Edison which only serves New York City will have a far higher percentage of costs driven by its congested urban challenges versus Commonwealth Edison which serves Chicago but also huge areas throughout the state of Illinois.

e) In PEG's total cost model the percentage of overhead line has a negative parameter estimate. In PEG's capital cost model the variable is positive, which does not align with the theory that it is underground lines that are more capital intensive. In PEG's OM&A model the variable is positive, which does align with theory. Please explain how it makes logical sense that in PEG's models overhead lines increase costs and are statistically significant in PEG's models for both capital and OM&A but then decrease total costs and the variable is statistically significant. Does this imply an error or misspecification in one or multiple of PEG's models?

Responses:

The following responses were provided by PEG.

a) An engineering explanation is not required. The econometric total cost model featured in PEG's empirical report was estimated using mean-scaled values of the two area variables. If $\hat{\beta}_{AU}$ and $\hat{\beta}_{AO}$ are the parameter estimates for congested urban area ("AU") and other area ("AO") *without* mean scaling, then *with* mean scaling the corresponding parameter estimates are $\overline{AU}\ x\ \hat{\beta}_{AU}$ and $\overline{AO}\ x\ \hat{\beta}_{AO}$ where $\overline{AU}$ and $\overline{AO}$ are the sample means of the two area variables. Because the mean area that is not congested urban is far larger than the mean area that is, mean-scaling will tend to raise the value of the AO parameter relative to the value of the AU parameterWhen the total cost model is estimated without mean-scaling the area variables, the parameter estimate for AU is much higher than that for AO. The benchmarking results are the same. Please see the table below for details.

   Consider also that all of the values for each utility's total service territory area are static for the entire sample period. If the goal of the econometric modeling exercise was to measure the cost impact of adding a square kilometer to a utility's territory, then it might make sense to spend more time considering alternative specifications. However, at sample mean values of the variables, the non-logged total area not congested urban variable in this model is effectively functioning to account for the sample average effects of overall service territory size. The total area congested urban variable then further modifies expected cost only for utilities with congested urban areas. Using Clearspring's time-variant version allows for increasing congested urban area more plausibly than with Clearspring's PCTCU variable.

PEG's Econometric Model of Power Distributor Total Cost

VARIABLE KEY

N =	Number of Customers	
D =	10-Year Rolling Avg of Distribution Peak	
N*N =	Number of Customers squared	
D*D =	Distribution Peak squared	
N*D =	Number of Customers squared	
AREACU =	Area Congested Urban	(not meanscaled)
AREAOTHER =	Area Not Congested Urban	(not meanscaled)
PCTELEC =	% of Line Plant OH	
PCTAMI =	Percent AMI	
PCTODXG =	Percent Distribution O&M of Transmission, Distribution, and Generation O&M	
FOR =	Percent Forestation in Service Territory	
DXWORK =	% Distribution Lines Over 50 kV	
TREND =	Time Trend	

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.423***	54.697	0.000
D	0.532***	59.797	0.000
N*N	0.696***	6.049	0.000
D*D	1.131***	10.239	0.000
N*D	-0.898***	-7.818	0.000
AREACU	0.00952***	26.445	0.000
AREAOTHER	0.00000182***	23.185	0.000
PCTELEC	0.0792***	5.371	0.000
PCTAMI	0.0127***	3.389	0.001
PCTODXG	0.0899***	11.052	0.000
FOR	0.0475***	32.749	0.000
DXWORK	0.179***	8.476	0.000
TREND	-0.0022	-1.577	0.115
CONSTANT	13.11***	1005.513	0.000

Adjusted R^2	0.972
Sample Period	2007-2021
Number of Observations	1,143

b) This statement is confirmed.

c) PEG confirms this statement.

d) PEG's total cost benchmarks are sensitive to the mix of congested urban and other area that a utility serves. Please see the response to M3-TH-5e.

e) This result was simply a labeling error that occurred when transferring the model output to an Excel spreadsheet. The table for the PEG's capital cost model with the corrected labels is provided below. You will find the overhead line variable does indeed align with theory and with the OM&A model. The model itself and its results are identical; the labels for percent of line plant overhead, percent of customers electric, and percent of customers with AMI have been corrected. The mislabeled model showed percent of electric customers as having a negative sign; the positive sign is correct and consistent with theory.

PEG's Econometric Model of Power Distributor Capital Cost

VARIABLE KEY

N=	Number of Customers
D=	10-Year Rolling Avg of Distribution Peak
N*N=	Number of Customers squared
D*D=	Distribution Peak squared
N*D=	Number of Customers squared
AREACU=	Area Congested Urban
AREAOTHER=	Area Not Congested Urban
PCTOHL=	% of Line Plant OH
PCTELEC=	% Electric Customers
PCTAMI=	%AMI
DXWORK=	% Distribution Lines Over 50 kV
TREND=	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.474***	50.258	0.000
D	0.522***	71.918	0.000
N*N	0.360***	5.528	0.000
D*D	0.688***	13.044	0.000
N*D	-0.512***	-8.790	0.000
AREACU	0.0234***	7.492	0.000
AREAOTHER	0.0288***	14.500	0.000
PCTOHL	-0.045	-1.585	0.113
PCTELEC	0.0965***	5.157	0.000
PCTAMI	0.0237***	17.641	0.000
DXWORK	0.126***	5.455	0.000
TREND	-0.001	-0.560	0.576
CONSTANT	10.59***	572.752	0.000

Adjusted R^2	0.969
Sample Period	2007-2021
Number of Observations	1,143

M3-TH-018

Reference: PEG Clearspring Report, p. 46 "Clearspring also updated its previously-presented econometric reliability benchmarking models…".

Interrogatory

Please explain why PEG did not produce reliability benchmarking results in its report.

Response:

The following response was provided by PEG.

Ontario Energy Board staff chose not to fund development of reliability benchmarking models by PEG.

M3-TH-019

Reference: PEG Clearspring Report, p. 55 “The formula for the X factor can then be restated as:

$$X = [(\overline{Productivity}^{C} - \overline{MFP}^{Economy}) + (\overline{Input\ Prices}^{Economy} - \overline{Input\ Prices}^{Industry})]. \quad [14]$$

PEG decided to undertake research and provide a recommendation on the “Productivity^{C}” term of the equation above. However, PEG does not make recommendations on the remaining components of what cost theory says should be the proper design of the X factor.

Interrogatories

a) Did PEG undertake research on the remaining three components of the X factor for this application? If so, please provide any research or analysis undertaken. If not, please explain why PEG believes only one of the four components of the X-Factor required research.

b) Please confirm that the OEB inflation factor is comprised of two indexes, which is primarily driven by GDP-IPI and to a lesser extent AWE.

c) If the input price inflation of the economy is lower than the input price inflation that Toronto Hydro faces, should this be considered in the plan design and lower the X-Factor for Toronto Hydro?

d) Please confirm that PEG has found that industry input price inflation in the U.S. is substantially higher than GDPPI inflation.

e) Is PEG of the view that Toronto Hydro faces similar input price inflation as its U.S. peers?

f) PEG states that the factors above have “contributed to the approval of substantially negative X factors in several American MRPs for energy distributors.” Would PEG support a negative X factor if the empirical data show that the four components above for Toronto Hydro result in a negative X factor?

g) What are the merits of a negative X-factor in the context of enabling a clean energy transition which necessitates additional funding for prudent investments in the grid and operations?

h) Please confirm that in Dr. Mark Newton Lowry's (PEG President) direct testimony on behalf of Puget Sound Energy to the Washington Utilities and Transportation Commission Docket UE-240004 in February 2024, PEG put forth the rationale for a "regional inflation differential" and inserted a 0.35% wage rate growth adjustment for Seattle compared to the U.S.

i) Please confirm that in that same testimony on behalf of Puget Sound Energy, PEG emphasized the critical importance of examining input price inflation in a multi-year rate plan.

j) If the input price inflation in Toronto is higher than in Canada or Ontario, would PEG support lowering the X factor accordingly?

k) Has PEG undertaken an investigation if the input price inflation in Toronto is lower than in Canada/Ontario? If so, please provide the analysis. If not, please explain why not.

Responses:

The following responses were provided by PEG.

a) PEG did not calculate Canada-specific input price and productivity differentials for the same reason that we did not calculate inflation differentials. As explained in Section 5 of our empirical report,

$$\textit{growth MFP}^{Industry} + (\textit{growth GDPPI} - \textit{growth Input Prices}^{Industry})$$

$$= \textit{growth MFP}^{Industry}$$

$+ \text{ } growth\ Input\ Prices^{Economy} - growth\ MFP^{Economy} - growth\ Input\ Prices^{Industry}$

$= (growth\ MFP^{Industry} - growth\ MFP^{Economy})$

$+ \text{ } growth\ Input\ Prices^{Economy} \text{ -}+ growth\ Input\ Prices^{Industry}$

Thus, the productivity and input price differentials are just another way to talk about the industry productivity trend and inflation differential. PEG did review the productivity of the Canadian economy as discussed in our response to question M3-TH-002, part f).

b) This statement is confirmed. However, the labor price index does matter and Canada's economy does have a history of sluggish or negative productivity growth.

c) The issue is whether an inflation differential between the Board's inflation measure and Toronto area input prices is material and can be demonstrated without undue cost and controversy.

d) This statement is confirmed, but the reasons for this are not obviously transferable to Ontario IR.

e) Please see the response to M3-TH-021, part f).

f) An adjustment to the revenue cap index formula could be warranted if it could be demonstrated convincingly without undue cost and controversy that these terms were negative on balance. However, the adjustment for the inaccuracy of the inflation measure does not have to be part of the X factor.

g) This is one way to help fund any higher costs of a clean energy transition and, if defensible, might be preferable to heavy reliance on utility cost forecasts as THESL proposes. However, the potential usefulness of a negative X factor in this role is greatly diminished if the utility nonetheless seeks to base revenue growth on forecasted cost growth since in that event there is no cost efficiency growth markdown.

h) Dr. Lowry has proposed a regional inflation differential adjustment to the national labor price inflation that is used in Puget Sound Energy's cost projections. Differences in the macroeconomic inflation in metropolitan Seattle and the U.S. were not deemed reliable. The OEB already uses an Ontario-specific labor price index in its inflation factor formula. This is likely to be quite sensitive to labor price inflation in Toronto's metropolitan area, which is Canada's largest.

i) This statement is confirmed, and PEG has shown an interest in input price metrics in EB-2023-0195 by proposing upgraded input price indexes.

j) PEG would support some adjustment to the indexing formula in the event that input price inflation in metropolitan Toronto could be demonstrated convincingly without undue complication to materially exceed that of the OEB's inflation factor, which is already based in part on Ontario labor price inflation.

k) Please see our response to Question M3-TH-002, part h).

M3-TH-020

Reference: PEG Clearspring Report, p. 52 “Even weighted averages are more pertinent in X factor studies for medium or smaller-sized utilities.”

Interrogatory

PEG states on page 29 that Toronto Hydro’s customer count and peak demands are below the sample average (0.77 and 0.89 of the sample average, respectively) and its real costs are right at the sample average (1.02). Does PEG consider Toronto Hydro a medium sized utility relative to the U.S. sample? If not, please explain.

Response:

The following response was provided by PEG.

Yes.

M3-TH-021

Reference: PEG Clearspring Report, p. 67 “However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities. In this study we use a new proxy M&S price index that is discussed further in Appendix section A.3.”

Interrogatories

a) Please confirm this is a change from PEG’s Hydro One Joint Report input price assumptions.

b) Please confirm that PEG’s new approach increases U.S. input prices.

c) Please confirm that PEG’s new approach will tend to increase its U.S. TFP trend findings.

d) Did PEG implement this new input price approach for both its U.S. TFP trend research and its cost benchmarking research?

e) Did PEG conduct similar research regarding Toronto Hydro’s M&S input price inflation as it did for U.S. utilities? If yes, please provide the analysis. If not, please explain why not.

f) Please calculate and provide a table showing the U.S. sample average annual growth rate for the M&S input price from 2007 to 2022, Toronto Hydro’s annual growth rate for the M&S input price from 2007 to 2022, the U.S. sample’s average annual growth rate for the OM&A input price from 2007 to 2022, Toronto Hydro’s annual growth rate for the OM&A input price from 2007 to 2022, the U.S. sample’s average annual growth rate for the total input price used in the econometric model from 2007 to 2022, and Toronto Hydro’s annual growth rate for the total input price used in the econometric model from 2007 to 2022.

g) Assuming Toronto Hydro’s input prices are assumed by PEG to grow markedly slower than the U.S. sample, can PEG provide an explanation for the difference in input price assumptions.

Responses:

The following responses were provided by PEG.

a) This statement is confirmed. The research and testimony for Puget Sound Energy that PEG has undertaken since the Joint Report has alerted us to the need to refine some of our input price inflation metrics. PEG's empirical research has numerous sponsors and we strive to upgrade our methods as the need and opportunity for upgrades arise.

b) PEG confirms that the upgraded approach to calculating a material and service price index ("WMS") tends to accelerate the estimated inflation of these prices.

c) PEG confirms that the upgraded approach to calculating WMS inflation tends to accelerate estimated TFP growth.

d) Yes

e) Yes. As a result of our research we expanded the weight on labor in THESL's OM&A input price index.

f) Please see the table below for the requested calculations. The calculations for the OM&A and total input price indexes reflect a correction for values prior to 2013 that was discovered when preparing this response. Like the Clearspring work, the PEG econometric work only used US data through 2021 and the trends are presented through 2021 instead of the requested 2022 end date.

   Inspecting the results, it can be seen that the O&M input price trends of THESL and the sampled U.S. power distributors were similar. Capital price growth was considerably more rapid in the U.S. Clearspring evidently used the same capital price index in its research.

Summary of Input Price Indexes Used in Econometric Work: 2007-2021 Trends

	Toronto Hydro	US
M&S	2.09%	2.46%
O&M	2.26%	2.31%
Total	1.85%	2.61%

The correction referenced above relates to 2 lines of PEG-added code which needed “[+1]” in the formula to properly calculate pre-2012 price index levels from the growth rates. PEG believes that this comment is sufficient to allow Clearspring to identify the error and correction and therefore avoid referring to confidential workpapers in this response.

g) PEG has not considered how or why the inflation in THESL’s input price index might differ from that of the U.S. utilities in our sample.

M3-TH-022

Reference: PEG Clearspring Report, p. 68 “We used only one scale variable in our U.S. power distributor productivity research: the number of customers served.”

Interrogatories

a) Please confirm that cost theory, and PEG itself, states that the output index in a revenue cap plan should be cost elasticity weighted. PEG shows this on p. 49 in Equation 6, p. 51 in Equation 7 and 8b and 9, on p. 53 on 10a, p. 55 in Equation 14. All these indicate that the output index should be cost elasticity weighted.

b) Please confirm that PEG uses peak demand as an output in its total cost econometric model.

c) Why has PEG not included peak demand in its U.S. TFP trend research?

d) Please provide a new table 11a and 11b showing the U.S. TFP trends using the two outputs of customers and the 10-year moving average distribution peak demand variable used by PEG in the benchmarking dataset and cost-elasticity weighting them based on PEG’s total cost econometric model.

e) Please confirm that part d now shows the TFP trend with the same output quantity calculation procedure (cost elasticity weighted with customers and the 10-year moving average of peak demand) as PEG used when calculating Toronto Hydro’s productivity trend show on Table 9a.

f) If PEG’s TFP trend research is used with only customers as an output, would PEG then consider it necessary in order to align with cost theory to reduce the stretch factor by the forecasted customer growth average annual growth rate (which is approximately 0.35%)?

Responses:

The following responses were provided by PEG.

a) This statement cannot be confirmed. Cost theory supports the use of a multidimensional scale index in a productivity study if the goal of the study is to measure cost efficiency. However, when the goal of the productivity study is to calibrate the X factor of a revenue cap index that uses the number of customers as the scale escalator, the number of customers should also be used to measure output. Insofar as the number of customers is an inaccurate stand-alone measure of operating scale, this will be reflected in the TFP trend calculation that informs selection of the X factor.

b) This statement is confirmed.

c) PEG did not use a multidimensional scale index in the U.S. productivity research because the goal of this research was to calibrate the X factor of a revenue cap index for THESL.

d) PEG is unable to produce these productivity results in a manner that is consistent with the original study to present on an alternative Table 11a. Data are not available to create a 10-year rolling average peak and a start data of 1995. In addition, not every company in the PEG sample has quality peak demand data available and a reduction in sample would be required.

e) Please see our response to part d) of this question. However, the goal of the THESL productivity research was to measure the cost efficiency of THESL. PEG's report does not compare the productivity growth of THESL to that of the U.S. sample in its report.

f) We cannot answer this question because we do not understand it.

M3-TH-023

Reference: PEG Clearspring Report, p. 42 “PEG constructed the output quantity index as an elasticity-weighted average of the growth in number of customers and the growth in a 10-year moving average of distribution peak demand.”

Interrogatories

a) Please revise Table 9a using the customer growth as the only output, in the same manner as PEG originally produced the U.S. TFP results.

b) What is the rationale for using different output definitions for calculating the U.S. TFP and the THESL TFP?

Responses:

The following responses were provided by PEG.

a) The requested analysis is not relevant for reasons stated in the response to question M3-TH-022, parts a) and e).

b) As also stated elsewhere in PEG’s responses, the U.S. productivity research was intended to calibrate the X factor of a revenue cap index whereas the THESL productivity research was intended to shine light on the company’s cost performance.

M3-TH-024

Reference: PEG Clearspring Report, p. 82 "We have chosen method 3) for our research in this project. The input price inflation of the U.S. economy is measured each year as the difference between GDPPI growth and a three-year moving average of the MFP growth of the U.S. private business sector.

Interrogatories

a) In order to assist in understanding this adjustment, please provide a year by year table with each component and showing the calculations for producing the input price inflation index?

b) Is this adjustment only applied to the M&S input price? Does PEG calculate the OM&A labour input price and capital service price in the same manner as it did in the Hydro One Joint Report?

c) Why does PEG apply a 50/50 weighting for Toronto Hydro instead of a 2/3 and 1/3 like it does for the U.S. M&S input price?

d) Did PEG investigate the Canadian MFP to see if an adjustment should be made? If so, please provide the analysis.

e) Does the Standard & Poor's Power Planner service have estimates for Canada, Ontario, or Toronto? If so, please provide.

f) Does the M&S input price adjustment for the U.S. sample made by PEG increase the U.S. TFP trend?

g) Please provide the U.S. TFP trend tables without making this new M&S input price adjustment but rather using GDPPI which was the index used in the Joint Report.

h) Was this adjustment also applied to the econometric cost benchmarking research of PEG? If so, please provide Toronto Hydro results using only the GDPPI for U.S. distributors to match the method PEG used in the Hydro One Joint Report.

i) Does PEG believe that Toronto Hydro is facing substantially lower input price inflation than its U.S. peers? If so, please explain the basis for this belief.

j) If Ontario MFP was positive, would PEG then consider it reasonable to make an M&S input price adjustment for Toronto Hydro similar to what was made for the U.S. utilities? If not, please explain.

Responses:

The following responses were provided by PEG.

a) Please see the table below which illustrates the method used to calculate the M&S part of the O&M price trend index found in the PEG working papers. The values used correspond to the index development for the econometric work using the modified Clearspring SST code. The method used is the same for the U.S. TFP trend work, but the labor price index will be different.

Adjusted M&S Trend Index Calculation

	M&S Cost Not Outsourced		M&S Cost Outsourced US = 66.67% ; THESL = 75%				Adjusted M&S Price Index	
	Assumed to be non-labor US = 33.33%; THESL = 25%		Assumed to be labor 50% for Both US and THESL		Assumed to be non-labor 50% for Both US and THESL		US Sample	Toronto Hydro
	US Input Price Index = GDPPI + US MFP Avg	THESL Price Index = GDP IPI FDD + 0% MFP	US Price Index = ECI Utilities	THESL Price Index = Fixed Weighted Index of AHE Ontario Industrial Aggregate	US Price Index = GDPPI + US MFP	THESL Price Index = GDP IPI FDD + 0% MFP	US = 33.33% x A1 + 66.67% x 50% x B1 + 66.67% x 50% x A1	THESL =25% x A1 + 75% x 50% x B1 + 75% x 50% x A1
	A1	A2	B1	B2	A1	A2		
2003	3.56%	1.67%	3.08%	2.66%	3.56%	1.67%	3.40%	2.00%
2004	4.85%	1.76%	2.94%	2.45%	4.85%	1.76%	4.21%	1.99%
2005	5.11%	2.08%	2.50%	3.15%	5.11%	2.08%	4.24%	2.44%
2006	4.43%	2.26%	3.08%	2.34%	4.43%	2.26%	3.98%	2.29%
2007	3.34%	2.43%	3.20%	3.83%	3.34%	2.43%	3.29%	2.90%
2008	1.73%	2.47%	3.14%	3.08%	1.73%	2.47%	2.20%	2.68%
2009	0.56%	1.06%	2.78%	2.89%	0.56%	1.06%	1.30%	1.67%
2010	1.86%	1.05%	2.44%	3.80%	1.86%	1.05%	2.05%	1.96%
2011	2.88%	2.37%	2.73%	1.59%	2.88%	2.37%	2.83%	2.11%
2012	2.75%	1.61%	2.43%	1.34%	2.75%	1.61%	2.64%	1.52%
2013	1.97%	1.69%	2.73%	1.42%	1.97%	1.69%	2.22%	1.60%
2014	2.33%	2.33%	2.68%	1.57%	2.33%	2.33%	2.45%	2.08%
2015	1.54%	1.53%	2.46%	2.70%	1.54%	1.53%	1.85%	1.92%
2016	1.39%	1.04%	2.32%	2.27%	1.39%	1.04%	1.70%	1.45%
2017	2.26%	1.39%	2.69%	1.86%	2.26%	1.39%	2.40%	1.55%
2018	2.68%	1.56%	2.41%	2.29%	2.68%	1.56%	2.59%	1.80%
2019	2.52%	1.80%	2.75%	2.79%	2.52%	1.80%	2.60%	2.13%
2020	1.88%	1.68%	2.20%	3.27%	1.88%	1.68%	1.99%	2.21%
2021	5.86%	3.87%	2.62%	2.78%	5.86%	3.87%	4.78%	3.51%
Average Annual								
2003-2021	2.82%	1.88%	2.69%	2.53%	2.82%	1.88%	2.77%	2.09%
2007-2021	2.37%	1.86%	2.64%	2.50%	2.37%	1.86%	2.46%	2.07%

b) Yes. This is not surprising since the use of GDPPI inflation as the sole basis for calculating inflation factors in American indexed ARMs is the primary reason why productivity differentials are considered in U.S. proceedings. The adjustment was only applied to the M&S price index in order to address problems that are specific to this index. This is an upgrade from the method that we used in the Hydro One Joint Report. The labor price index for THESL has been changed to use the FWI AHE as explained in Section 8 of the report. The capital price index in the productivity work includes a capital gains term, as is customary.

c) Please see the response and table to part a) above. PEG assumes that the labor and materials of outsourced services for both Toronto Hydro and U.S. distributors are split 50/50. We assume that the proportion of M&S that is outsourced services is 2/3 for U.S. distributors and 75% for Toronto Hydro. The 2/3 estimate for the U.S. is a conservative estimate based on our recent work for Puget Sound Energy. Our 75% figure is based on information provided by Toronto Hydro. PEG does not consider 66% to be different enough from 75% to make a material difference in the conclusions of this study. Absent information from Toronto Hydro, PEG would have used the same assumption as was done for the U.S.

d) Yes. As shown in the response to M3-TH-2f, Canadian MFP growth has tended to be close to zero or negative and adding this to a Canadian macro inflation measure would slow or not affect calculated input price growth.

e) No. To the best of our knowledge Power Planner has never calculated input price indexes for Canadian utilities.

f) Yes.

g) Please see the table below with alternative productivity results. It can be seen that TFP growth slows modestly because OM&A productivity growth slows materially. Since THESL has asked for a forecasted ARM for its OM&A revenue, the relevance of upgrading the OM&A input price index is apparent.

h) Yes. PEG declines to comply with this request on the grounds that it is more difficult to undertake than the request made in part g) of this question and in view of the limited time and budget available to answer to numerous questions.

US Power Distributor Productivity Growth

Year	Simple Averages of Annual Productivity Growth Rates			Cost-Weighted Averages of Annual Productivity Growth Rates		
	Total Factor	OM&A	Capital	Total Factor	OM&A	Capital
1996	-0.37%	-0.99%	0.05%	-0.41%	-1.37%	0.05%
1997	1.74%	3.24%	0.72%	1.36%	2.38%	0.67%
1998	-0.42%	-2.82%	1.09%	-2.04%	-6.29%	1.03%
1999	-1.34%	-3.49%	-0.02%	-1.07%	-3.31%	-0.03%
2000	1.02%	2.62%	-0.07%	0.54%	1.29%	0.13%
2001	2.11%	3.99%	0.78%	2.43%	4.02%	1.27%
2002	0.99%	2.48%	0.03%	0.69%	3.39%	-1.03%
2003	-0.28%	-1.34%	0.37%	0.10%	-0.44%	0.07%
2004	2.21%	5.49%	0.09%	3.16%	7.82%	0.18%
2005	0.98%	1.42%	0.67%	0.85%	0.66%	1.00%
2006	2.18%	3.94%	0.22%	1.94%	3.88%	0.00%
2007	-2.29%	-4.13%	0.50%	-3.37%	-6.41%	0.97%
2008	-1.62%	-2.07%	-0.44%	0.00%	-0.03%	0.22%
2009	2.40%	4.10%	0.30%	3.01%	4.94%	0.59%
2010	-0.02%	-0.72%	0.81%	-0.56%	-1.98%	0.85%
2011	0.38%	0.37%	0.42%	0.48%	0.17%	0.71%
2012	0.73%	2.33%	-0.21%	1.38%	3.49%	0.24%
2013	0.65%	1.79%	0.06%	1.37%	2.88%	0.59%
2014	0.03%	-0.53%	0.40%	-0.08%	-0.86%	0.42%
2015	0.19%	0.22%	0.26%	1.12%	2.58%	0.30%
2016	-0.54%	-1.63%	0.04%	-0.46%	-1.54%	0.08%
2017	0.19%	1.56%	-0.35%	0.44%	2.45%	-0.20%
2018	-1.48%	-3.46%	-0.67%	-1.22%	-3.18%	-0.49%
2019	-0.18%	2.05%	-1.26%	0.55%	3.43%	-0.78%
2020	0.12%	2.35%	-0.82%	-0.58%	0.03%	-0.63%
2021	-0.21%	0.90%	-0.76%	-0.64%	0.13%	-1.01%
2022	-1.96%	-4.17%	0.15%	-1.34%	-2.96%	0.29%
Average Annual Growth Rates						
All Years (1996-2022)	**0.19%**	**0.50%**	**0.09%**	**0.28%**	**0.56%**	**0.20%**
Last 15 Years (2008-2022)	**-0.09%**	**0.21%**	**-0.14%**	**0.23%**	**0.64%**	**0.08%**
Last 10 Years (2013-2022)	**-0.32%**	**-0.09%**	**-0.29%**	**-0.08%**	**0.30%**	**-0.14%**
Last 5 Years (2018-2022)	**-0.74%**	**-0.47%**	**-0.67%**	**-0.64%**	**-0.51%**	**-0.53%**

i) Please see the response to M3-TH-21, part f) for PEG's calculations in this matter. For the econometric work, PEG used the same data and forecast assumptions as Clearspring with the exception of an improved labor price for THESL and a few methodological improvements related to the M&S price index. As per the table to part a of the response to this question, from 2007 to 2021 the labor price inflation for the U.S. has been about 0.14% more rapid than for Ontario. The non-labor M&S price inflation has been about 0.51% more rapid in the U.S. The difference in estimated capital price inflation is evidently a big part of the reason for more rapid overall input price inflation. PEG does not see any a priori reason why the input price growth of Toronto should be any more or less rapid than elsewhere. We would also like to note that both the OM&A and total input price indexes used by Clearspring also show more inflation for the U.S. than for Toronto Hydro from 2007 to 2021.

j) PEG's adjustment of the WMS for U.S. utilities is not based solely on the fact that the MFP growth of the U.S. economy is positive. It is also based on a credible estimate of the growth in the materials price inflation of power distributors that is unavailable for Canada. PEG did upgrade THESL's O&M price index.

M3-TH-025

Reference: PEG Working Papers

Interrogatories

a) In PEG's econometric STATA do-file code titled, "PEG THESL Econometric Models", on line 72, PEG appears to calculate total costs divided by the total cost input price. However, the code is dividing capital cost ("ckd") by the total input price. Please explain why only the capital costs are in the numerator and where in the code the OM&A costs are being added. If this was an error and requires a correction, please provide all tables that may be affected.

b) It appears that the two area variables are not logged in the model based on our examination of the code. Please confirm or correct this statement.

c) If verified that the two area variables are not logged, does this imply that the model estimates that adding one km squared of "other" area adds substantially more to total costs than adding one km squared of "congested urban" area? If so, please explain how that aligns with the understanding that congested urban is one of the most costly areas to serve?

d) Did PEG consider logging the two area variables like it logged the total area in the Hydro One Joint Report research? If so, please provide the results of those models.

e) Please provide other examples of testimony that PEG has produced in North America where the area variable has not been logged.

f) Please provide other examples of testimony that PEG has produced in North America where PEG has broken out the area variable into congested and non-congested.

g) Please provide other examples of testimony that PEG has produced in North America where PEG has not translogged (interacted with the other outputs and taken the quadratic) the area variable.

h) Please point us to where in the working papers the new U.S. “wndxus” input price is being calculated and where the raw data is for those calculations for this new input price.

i) Is PEG using a different rate of return assumption in its U.S. TFP research versus the econometric benchmarking research? If so, please explain why PEG is not using the same assumption.

j) If PEG is using a different rate of return assumption in its U.S. TFP research, please provide the Table 11a and 11b using the rate of return assumptions used in the econometric benchmarking research which follow the OEB’s approved rate of returns.

Responses:

The following responses were provided by PEG.

a) PEG acknowledges that an error was made here. Please see the total cost and OM&A cost models below for revised results. The error was introduced late in the process when the upgraded M&S price index was being introduced into the model. It did not result in much change in results partly because capital cost is a large share of total cost. As can be seen, the results are robust with respect to the evaluation of Toronto Hydro’s total cost performance. We removed the percent overhead line variable from the corrected model because the correction to the cost specification resulted in a statistically insignificant parameter.

   We also present below a revised model of OM&A cost that reflects a small correction to the data used in its estimation. Both this model and the total cost model include a correction to pre-2012 price index values as discussed in the response to M3-TH-021 part f.

   The year-by-year benchmarking results for Toronto Hydro using the corrected models (and the capital cost model, which didn’t require correction) are presented in the third table below.

PEG Corrected Model of Total Distributor Cost

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTELEC =	% of Line Plant OH
PCTAMI =	Percent AMI
PCTODXG =	Percent Distribution O&M of Transmission, Distributic
FOR =	Percent Forestation in Service Territory
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.423***	54.697	0.000
D	0.532***	59.797	0.000
N*N	0.696***	6.049	0.000
D*D	1.131***	10.239	0.000
N*D	-0.898***	-7.818	0.000
AREACU	0.0215***	26.445	0.000
AREAOTHER	0.0428***	23.185	0.000
PCTELEC	0.0792***	5.371	0.000
PCTAMI	0.0127***	3.389	0.001
PCTODXG	0.0899***	11.052	0.000
FOR	0.0475***	32.749	0.000
DXWORK	0.179***	8.476	0.000
TREND	-0.0022	-1.577	0.115
CONSTANT	13.11***	1005.514	0.000

Adjusted R^2	0.972
Sample Period	2007-2021
Number of Observations	1,143

PEG Corrected Model of Distributor OM&A Cost

VARIABLE KEY

N =	Number of Customers
D =	10-Year Rolling Avg of Distribution Peak
N*N =	Number of Customers squared
D*D =	Distribution Peak squared
N*D =	Number of Customers squared
AREACU =	Area Congested Urban
AREAOTHER =	Area Not Congested Urban
PCTOHL =	% of Line Plant OH
DXCSI =	Distribution Construction Standards Index
FOR =	Percent Forestation in Service Territory
DXWORK =	% Distribution Lines Over 50 kV
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.549***	21.171	0.000
D	0.376***	17.069	0.000
N*N	1.163**	3.163	0.002
D*D	1.627***	4.815	0.000
N*D	-1.368***	-3.888	0.000
AREACU	0.0318***	5.933	0.000
AREAOTHER	0.0452***	8.712	0.000
PCTOHL	0.431***	6.342	0.000
DXCSI	0.450***	13.341	0.000
FOR	0.0738***	15.778	0.000
DXWORK	0.155**	2.994	0.003
TREND	-0.00706***	-4.613	0.000
CONSTANT	11.99***	659.437	0.000

Adjusted R^2	0.885
Sample Period	2007-2021
Number of Observations	1,143

Year-by-Year Distributor Cost Benchmarking Results

	[Actual - Predicted Cost]		
Year	**Total Cost Benchmark Score**	**Capital Cost Benchmark Score**	**OM&A Cost Benchmark Score**
2007	-26.85%	-20.82%	-11.58%
2008	-23.56%	-16.99%	-10.25%
2009	-21.21%	-15.87%	-5.17%
2010	-14.21%	-12.23%	10.00%
2011	-7.85%	-5.58%	15.37%
2012	-8.99%	-5.67%	11.22%
2013	-4.26%	-2.04%	17.50%
2014	-0.78%	3.16%	15.78%
2015	1.67%	7.24%	11.01%
2016	6.95%	13.90%	10.86%
2017	10.69%	18.40%	11.30%
2018	12.65%	19.46%	15.78%
2019	14.67%	21.13%	18.74%
2020	14.95%	22.65%	15.37%
2021	17.52%	24.48%	19.97%
2022	19.41%	27.47%	18.01%
2023	*22.89%*	*30.14%*	*23.31%*
2024	*24.52%*	*31.24%*	*26.12%*
2025	*26.62%*	*33.14%*	*28.23%*
2026	*28.92%*	*35.54%*	*29.41%*
2027	*30.82%*	*37.94%*	*28.91%*
2028	*32.92%*	*40.18%*	*29.67%*
2029	*35.18%*	*42.86%*	*29.69%*
Averages			
2020-2022	**17.30%**	**24.87%**	**17.78%**
Forecast Period 2023-2029	***28.84%***	***35.86%***	***27.90%***
CIR Period 2025-2029	***30.89%***	***37.93%***	***29.18%***

Notes

Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

b) This statement is confirmed. The area congested urban variable data obtained from Clearspring had a number of 0 values and thus could not be logged. The area not congested urban variable did not have any 0 values, but PEG did not log that variable in order to keep the variable treatment the same. This is desirable for consistent interpretation, and for the model parameters to capture the effects discussed in M3-TH-017, parts a) and d).

c) Please see the response to M3-TH-17, part a).

d) No, because it is not mathematically possible to log the area congested urban variable because of the numerous zero values. Clearspring did not log its congested urban variable.

e) PEG has rarely not logged business condition variables in econometric models but found it necessary in this case due to numerous zero values for the congested area variable. We developed this variable specification for this proceeding to address Toronto Hydro's congested urban cost challenge concerns. We investigated Clearspring's modified CU variable --- which was not presented in any of Clearspring's previous models --- and found it to be controversially constructed and distortional in its impact. Its parameter estimate was extremely sensitive to the sampled companies and implausible as an estimate of the cost impact of incremental growth in urban congestion.

f) Please see our response to part e) above. Both PEG and Mr. Fenrick have used area rural and area not rural variables in much older models. We believe that a standalone area congested variable is preferable to Clearspring's PCTCU variable. Using Clearspring's skyscraper adjustment to make the variable time-variant is controversial and inexact but allowed PEG to adjust its benchmarks for the expected increase in Toronto's urban congestion.

g) PEG did not translog the area variable in the first (total cost) model in which we used it in research for the OEB. In a subsequent update the area variable was not statistically significant and was removed from the model. PEG has used other measures of system extensiveness such as line length in cost models. We have not routinely translogged line length variables where we have used them.

h) The variable wndxus is constructed by adding the growth of the U.S. GDPPI and the MFP of the U.S. private business sector and converting the resulting growth rate to an index number. Please see the table below.

Construction of the Input Price Index for the U.S. Economy

	Growth				WNDXUS
	GDPPI	TFP Private Business Sector	3 Year Average MFP	wndxus	Index Number
1993					
1994		0.41%			
1995		-0.12%		0.00%	100.000
1996	1.81%	1.30%	0.53%	2.34%	102.368
1997	1.72%	1.12%	0.77%	2.49%	104.945
1998	1.10%	1.77%	1.39%	2.49%	107.595
1999	1.39%	2.15%	1.68%	3.07%	110.947
2000	2.26%	1.36%	1.76%	4.02%	115.496
2001	2.28%	0.48%	1.33%	3.61%	119.743
2002	1.49%	1.95%	1.27%	2.76%	123.089
2003	1.98%	2.31%	1.58%	3.56%	127.552
2004	2.64%	2.37%	2.21%	4.85%	133.894
2005	3.07%	1.45%	2.04%	5.11%	140.920
2006	3.06%	0.29%	1.37%	4.43%	147.305
2007	2.67%	0.27%	0.67%	3.34%	152.308
2008	1.86%	-0.96%	-0.13%	1.73%	154.960
2009	0.66%	0.40%	-0.10%	0.56%	155.834
2010	1.19%	2.56%	0.67%	1.86%	158.756
2011	2.04%	-0.45%	0.84%	2.88%	163.390
2012	1.85%	0.60%	0.90%	2.75%	167.951
2013	1.71%	0.62%	0.26%	1.97%	171.286
2014	1.73%	0.59%	0.60%	2.33%	175.331
2015	0.87%	0.80%	0.67%	1.54%	178.052
2016	0.95%	-0.07%	0.44%	1.39%	180.544
2017	1.81%	0.61%	0.45%	2.26%	184.667
2018	2.26%	0.70%	0.42%	2.68%	189.674
2019	1.67%	1.24%	0.85%	2.52%	194.516
2020	1.34%	-0.32%	0.54%	1.88%	198.209
2021	4.46%	3.28%	1.40%	5.86%	210.175
2022	6.82%	-1.71%	0.42%	7.24%	225.949
2023	3.57%	0.74%	0.77%	4.34%	235.966

i) Yes. For the econometric benchmarking work, PEG used the Clearspring capital cost data. PEG opted to use the Clearspring data for benchmarking so that its critique of the work could be isolated to areas in which PEG deemed important. It was a concession to make it easier for parties to compare the models and eliminate to the extent possible other sources of differences in results and should not be seen as endorsement of every choice made by Clearspring. The U.S. productivity work is a stand-alone study using a PEG data set in order to provide U.S. power distribution productivity results to inform the choice of the base productivity trend. Ontario data are not relevant to the calculation of U.S. productivity trends.

j) PEG declines to undertake this task. It is unduly burdensome given the time and budget available to answer IRs. It is also not relevant to U.S. productivity calculations.

M3-TH-026

Reference: PEG Clearspring Report, p. 6 “OEB Staff retained PEG to appraise and comment on Clearspring’s benchmarking evidence and the Company’s proposed rate framework.”

Interrogatory

Please provide the engagement letter and all related materials including any RFP and proposal response, and all written instructions provided to PEG, related to the preparation of PEG’s report.

Response:

The following response was provided by Board Staff.

Please see response for M1-TH-001 filed May 17, 2024.