Hydro One Networks Inc.

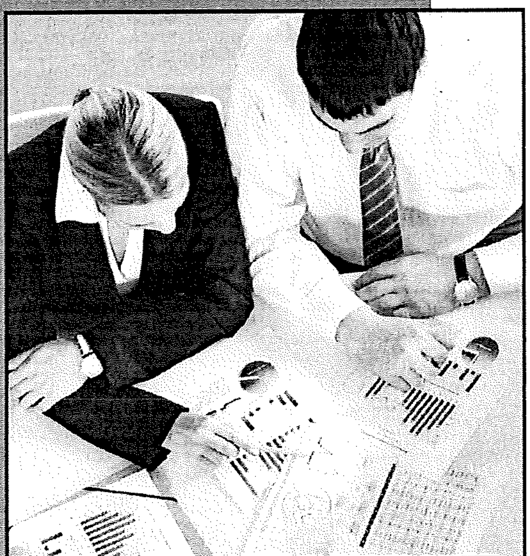
EB-2019-0082

<u>CME Compendium - Witness Panel #4</u>

October 31, 2019

Power System Engineering, Inc.

Full-service consultants



Transmission Study for Hydro One Networks:

Recommended CIR Parameters and Productivity Comparisons

Prepared by:

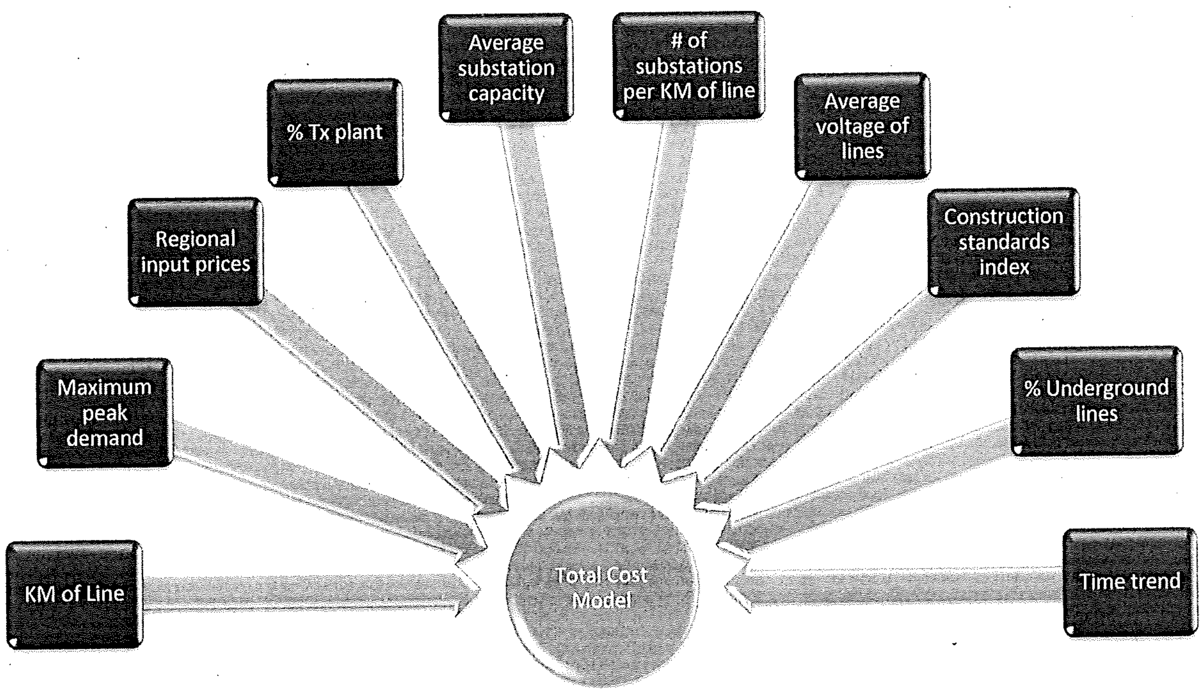
Power System Engineering, Inc.

January 24, 2019

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission plant in total electric utility plant,
- Average capacity in MVA per transmission substation,
- Number of transmission substations per kilometre of transmission line,
- Average voltage of transmission lines,
- Construction standards index for building a transmission pole,
- Percent of lines that are underground, and
- A time trend variable.

The variables included in the benchmark analysis are shown in the figure below.

Figure 4 Variables in Econometric Cost Model



The list of variables incorporated into the econometric model is extensive. These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All variables are statistically significant at a 99% confidence level, and all variables are correctly signed (i.e. they are signed the way we would expect).

3.2.1 Output Variables

The total cost model includes two **output variables**. The first is the total kilometres of transmission line, the second is the maximum peak demand for each utility during the sample period. The output variables are gathered from SNL Energy's database. The raw data was gathered by SNL Energy from FERC Form 1 filings. The historical output data for Hydro One comes directly from the company. The maximum peak demand variable is calculated based on taking the maximum annual peak demand on the system in the sample that has occurred up to that year. For example, for the 2005 observation, the variable is the highest annual peak demand for either 2004 or 2005. For the 2016 observation, the maximum peak demand is the highest annual peak that has occurred since 2004.[18]

3.2.2 Input Prices

Input prices are divided into two categories: capital and OM&A. The capital input price calculation (using the perpetual inventory capital cost method) is discussed in detail in Section 3.3 The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price: labour and non-labour.

The labour component is calculated by taking wage levels for numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics (BLS) estimates of job occupation weights in the *Electric Power Generation, Transmission, and Distribution Industry*. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from the 2011 Canadian census, using wage data for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency for the U.S. and Hydro One regarding labour input prices, and also puts the input price in terms of each country's currency.

The non-labour component of the OM&A input price uses the gross domestic product price index (US GDP-PI) for the U.S. utilities. The Ontario non-labour component uses the same US GDP-PI for each year, but adjusts for the purchasing power parity (PPP) index. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price, we weighted each index using a 38% labour and a 62% non-labour rate.[19] This was derived from the inflation factor research that examined the labour and non-labour components in transmission total costs. Using the capital and OM&A cost

[18] An adjustment was made for the three Southern Company utilities (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. These three utilities reported transmission peak demands on the FERC Form 1 for the entire Southern Company system rather than at the individual operating company level. We proportioned out the reported Southern Company transmission peak demand reported on p. 400 of the FERC Form 1 by the reported system peak data of each operating company reported on p. 401 of the FERC Form 1.

[19] Note: this weighting is a different weighting than the one described in Section 1.1.3 and Section 2.2.1. The weighting in this section (38% labour/62% non-labour) applies to OM&A costs, which are more labor-intensive and have a larger labour component. The weighting recommended in previous sections (14% labour/86% non-labour) applies to **total** costs.

shares, PSE calculated a total input price index.

Total cost is divided by this comprehensive input price to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. That is, as the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all a utility's purchases (including labour) increase by 10%, its costs would also increase by 10%. This is derived from production theory, which states that costs equal input quantity multiplied by input price.

3.2.3 Business Condition Variables: Other

Beyond the two output variables and the input price index, there are six additional business condition variables included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of transmission plant in total electric plant** uses gross plant in service information from FERC Form 1s.[20] The variable measures the ability for a transmission utility to reduce costs through economies of scope: if the utility is also a generation and/or distribution utility, there may be cost savings to the transmission utility because of this added scope. The coefficient on the variable is expected to be positive: the higher the percentage of transmission plant in total electric plant, the higher we would expect total costs to be.

The **average substation capacity** variable is measured in MVA. The variable measures the average capacity per transmission substation reported on each utility's FERC Form 1 for each year. For Hydro One the assets were reported directly to PSE. We would expect that costs would increase as the average capacity per substation increases.

The **number of transmission substations per KM of transmission line** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to PSE by Hydro One. We would expect a positive correlation between: (1) the number of transmission substations per KM of transmission line, and (2) total costs.

The **average voltage of transmission lines** measures the differences in voltage levels across transmission systems. This variable is constructed by calculating a weighted average by length of the different voltage levels found on each utility's transmission system. Serving higher voltages will be more costly than serving lower voltages, *ceteris paribus*. Therefore, we would expect a

[20] All FERC Form 1 data was gathered by PSE using SNL Energy's Excel extraction tool. The exception is the data on pages 422 to 427 of the FERC Form 1s. This data includes all data dealing with substations and details of the transmission lines. PSE gathered and processed this data manually because SNL does not provide the details necessary for variable construction.

Input prices are calculated using the same procedures as the historical data, but with inflation projections for 2018-2022.[22] Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour OM&A component is based on the Conference Board of Canada's projections for the GDP-IPI. The projections range from 1.8% in 2018 to 1.9% in 2022. The labour component uses the Conference Board of Canada's projections for average weekly earnings in Ontario. This ranges from 3.1% in 2018 to 2.3% in 2022. The capital category is set to increase using the Conference Board of Canada's projections for engineering structures, electric power generation, transmission, and distribution. This ranges from 2.3% in 2018 to 2.2% in 2022.

The plant additions for 2018-2022 are based on Hydro One projections. OM&A cost projections are set based on Hydro One projections for 2020, and then escalate by 1.98% per year from the 2020 value. This 1.98% figure is based on the inflation factor recommended weighting of 14% (labour) and 86% (non-labour) using the Conference Board of Canada's projections for Average Weekly Earnings in Ontario (labour component) and their GDP-IPI projections (non-labour component) minus the X factor and stretch factor, which are set at 0.0% each. See Section 2.2.1 for how the 14%/86% weights were determined.

The **percentage of transmission plant in total electric plant** projections are based on the historic variable value for Hydro One.

The **average substation capacity** projections are based on asset projections provided to PSE by Hydro One.

The **number of transmission substations per KM of transmission line** projections are based on asset projections provided to PSE by Hydro One.

The projections for **average voltage of transmission lines** are based on asset projections provided to PSE by Hydro One.

The projections for **percentage of underground lines** are based on asset projections provided to PSE by Hydro One.

The **construction standards index** variable is set to the same value throughout all historical and projected years for Hydro One.

3.3 Perpetual Inventory Capital Cost Method

This report evaluates Hydro One's capital costs as a component of the total cost definition. PSE's measure of capital cost is based on a service price approach. This approach has a solid basis in

[22] Input price data for 2017 was available and used in the 2017 observation for Hydro One.

economic theory, and is the same method used in the 4GIR research and PSE's research in Hydro One's distribution CIR application.[23] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period t is the product of indexes of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period t, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using data on the value of net transmission utility plant in a benchmark year, and on gross transmission plant additions in subsequent years. It also uses an assumption about service lives. We use 1989 as the benchmark year in the current study for all U.S. utilities. We use 2002 as the benchmark year for Hydro One. This is the first feasible year to use for Hydro One, due to lack of data availability in years prior to 2002.

Hydro One provided PSE with their net transmission plant and their transmission plant additions. These included an allocation for general plant. For the U.S. sample, PSE allocated a portion of net plant and general plant additions based on the ratio of transmission gross plant in service to total gross plant in service minus general and intangible plant.

Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 1989 or 2002. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. This method is used both for Hydro One and the U.S. utilities. The formulas for the capital quantity index in 2002 and in subsequent years are provided below.[24]

$$XK_{2002}^{i} = \frac{Net\ Plant_{2002}^{i}}{TWA_{2002}^{i}}$$

$$XK_t^i = XK_{t-1}^i * d + \frac{Add_t^i}{WKA_t^i}$$

[23] See Hall and Jorgensen (1967) for a discussion of the use of service price methods for measuring capital cost.

[24] For the U.S. utilities the formulas begin in 1989.

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all transmission utilities provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the value of 3.59% for this parameter, based on Hydro One's 2015 Depreciation Rate Study and the U.S. Bureau of Economic Analysis (BEA) declining balance rate of 1.65 for electrical transmission, distribution, and industrial apparatus.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power transmission. We compute this index using data on differences in the cost of constructing utility plants between regions, and within regions over time. In particular for U.S. transmitters, we use the Handy-Whitman indexes for total power transmission plants, which vary over time and across six geographic regions. For Hydro One, we used the Handy-Whitman index for the North Atlantic region and adjusted for the Canadian PPP.

We determined the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*. These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for both U.S. and Hydro One. The index is already adjusted for currency differences between the two countries.

3.4 Translog Cost Function

Section 3.2 above listed the variables used to benchmark transmission costs. These variables were all evaluated to quantify their effect on transmission costs. As a starting point for evaluating variables, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers" (i.e., the variables), can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

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OEB Staff Interrogatory # 66

Reference:
Exhibit D. Tab 1, Schedule 1, Attachment 1, Section 3.3 (Perpetual Inventory Capital Cost Model)

Interrogatory:
With respect to Section 3.3 of PSE's evidence on its Perpetual inventory Capital Cost Model:

a) Which cities in the RSMeans *Heavy Construction Cost Data* were assigned to Hydro One? If multiple cities were used, how were the index values averaged?

b) What RSMeans cities were used for each sampled U.S. utility? If multiple cities were used, how were the index values averaged?

c) Which version of the city cost index (e.g. materials, installation, total) was used?

d) When calculating the depreciation rate, does the 1.65 declining balance parameter used refer to just equipment, just structures or both? What would be the appropriate declining balance parameter for each type of plant?

e) Why is a 1989 benchmark year adjustment used for the U.S. utilities?

Response:
a) The city assigned to each utility in the sample for the RSMeans mapping, including Hydro One Networks, was based only on the headquarter city for each utility. In Hydro One Networks' case, this was Toronto.

b) The cities used for the RSMeans mapping was the headquarter city for each utility.

c) Total city cost index was used for the RSMeans variable.

d) The 1.65 declining balance parameter refers to just equipment for electrical transmission, distribution, and industrial apparatus. According to the BEA, the appropriate declining balance parameter for just structures would be 0.91.

e) 1989 is the earliest data available from the data supplied by SNL Energy to begin the capital stock series for the U.S. utilities. In Hydro One's case, the earliest year is 2002.

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FILE NO.:	**EB-2018-0218**	**Hydro One Sault Ste. Marie Inc. on Behalf of Hydro One Sault Ste. Marie LP**
VOLUME:	**Technical Conference**	**REDACTED - PUBLIC**
DATE:	**January 15, 2019**	

NET PLANT FOR A RECENT HISTORICAL YEAR.

MR. SIDLOFSKY: Mr. Shepherd?

MR. SHEPHERD: I just have a few questions left. I am on Staff 66, and Staff 66 says that -- I think it says that the construction cost assumed for Hydro One was the Toronto construction cost. Is that right, from the RSMeans index?

MR. FENRICK: Yes. Consistent with how we did the rest of the sample, we used the headquarter city as the map.

MR. SHEPHERD: How does construction costs feed into your model? It affects your capital model, right?

MR. FENRICK: It flows into the capital price. So when you do a benchmarking study, you want to levelize for the regional differences in the prices the utilities have to pay for, you know, for labour or for capital.

And so we use the RSMeans to provide that levelization on the capital price, to correct for the regional -- or adjust for the regional differences between utilities in construction costs.

MR. SHEPHERD: Now, the only component of this that matters is the Delta from year to year, right, because this is a rate of change calculation, right?

MR. FENRICK: No, that's not right. This is a levelization, so we are taking -- we did the levelization in 2012. So we took the RSMeans in 2012, and it's a book that has heavy construction costs for a whole host of cities through North America. We took the values, the headquarter city values for every utility in the sample, set that, and then we changed that trend using the Handy Whitman indexes. But in 2012, the levelization is based on the differences in the cities as reported by RSMeans.

MR. SHEPHERD: So basically you are saying that the expected costs for Hydro One, for example, will be different than for somebody whose headquarters is in Philadelphia, because construction costs are different in those two cities, right?

MR. FENRICK: Correct.

MR. SHEPHERD: All right. So did you adjust for the fact that Toronto is notoriously -- has the largest amount of construction activity of any city in North America?

MR. FENRICK: No, there was no adjustment made. We took -- we thought we were consistent throughout the whole sample and we didn't make adjustments to cities.

MR. SHEPHERD: So if Toronto's construction costs are affected by the high amount of construction activity and the inability to get people and cranes and stuff like that, how would that affect your results?

MR. FENRICK: Are you saying if those -- that reality increased the value found in RSMeans?

MR. SHEPHERD: Yes.

MR. FENRICK: It would increase the levelization factor for Hydro One.

MR. SHEPHERD: So it would mean that Hydro One's costs would be expected to be higher than peers in cities with lower construction costs.

MR. FENRICK: If the construction costs are higher in

Toronto then, all else being equal, the benchmark would be higher for Hydro One.

MR. SHEPHERD: So what is included in heavy construction? Does it including building condos and stuff like that? Or does it only include things that are specifically relevant to Hydro One, like transmission lines and things like that?

MR. FENRICK: It's the heavy construction, so it's not specific to the utility transmission business. So it would include, you know, condos and those types of things, heavy construction type.

MR. SHEPHERD: My next question is on Staff 68, and you've said in your answer to B that the incentives under the FERC rate plans are generally weaker than the incentives in Ontario plans, right? Is that a fair statement about what you said there?

MR. FENRICK: Yes, I consider formula rates to have weaker incentives than the typical incentive regulation regime here in Ontario.

MR. SHEPHERD: And the incentives we are talking are Basically cost control incentives, right -- mostly they are cost control incentives?

MR. FENRICK: That's fair.

MR. SHEPHERD: So wouldn't that necessarily mean that for regulatory reasons, U.S. transmitters would have worse productivity than Ontario transmitters? All other things being equal, that should be the case, right?

MR. FENRICK: With the caveat that formula rates have

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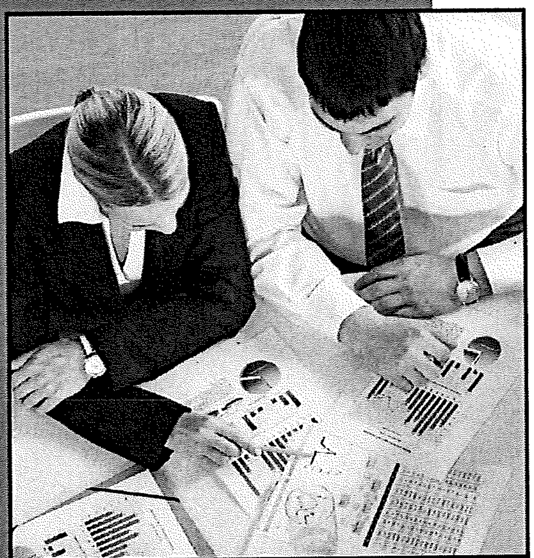

Reply to PEG's Report ("Incentive Regulation for Hydro One Transmission")

Prepared by:

Power System Engineering, Inc.
October 15, 2019

Hydro One's TFP and total cost benchmarking scores in the earlier years of the sample period however, that concern should cease to apply by the later years of the sample period.

3.2.5 Construction Standards Index Variable

PSE took the proper approach that is consistent with how the US sample is calculated. This approach used the service territory of each company, including Hydro One, to formulate the variable. If it were possible to switch to one based on calculating the variable based on the location of transmission lines for each company, the benchmarking results would likely improve for Hydro One. Despite PEG citing this as a concern, PEG refused to revise their results with a variable value that addressed these concerns.[40] PSE estimates that modifying the dataset to reflect PEG's concern would improve Hydro One's benchmarking score by about 3.5%. However, we do not believe this would be the proper approach, given the data limitations on the U.S. sample.

3.2.6 PSE Used the Same Input Price Inflation Index Assumptions for the Entire Sample

We view using the same input price inflation indexes for the studied utility and the rest of the sample in a benchmarking study as the better approach. This issue is inconsequential, given that both PSE and PEG levelized input prices after the major inflation index differences between the PSE and PEG capital indexes occurred. Both PSE and PEG levelized the capital in 2012. We also note that PEG used a similar approach to PSE when it used U.S. inflation indexes in their recent Ontario Power Generation research.

3.2.7 Hydro One's OM&A Expenses Grow by the Proposed Revenue Escalation Formula (i.e., Inflation)

PSE escalated Hydro One's OM&A expenses in the forecasted period based on the proposed revenue escalation formula of I – X, where X = 0. PEG takes the exact same approach in their benchmarking research.

PEG believes that the company's I-X revenue escalation formula will not provide the company with enough revenue escalation; we deduce this because PEG also believes it is a "rosy scenario" for expenses to increase by only inflation during the Custom IR period. When requested to offer PEG's view, PEG refused to provide an opinion on the appropriate OM&A productivity factor in the revenue escalation formula.[41]

3.2.8 Four Other Items

PEG lists four other concerns it describes as "less important.".

1. PEG correctly states that PSE used Toronto values to levelize the Company's construction cost index. PEG used the same values in its research.[42] PSE used the headquarter city for

[40] See PEG's response to EB-2019-0082, L1, Tab 1, Schedule 7, part c.

[41] Exhibit L1, Tab 1, Schedule 8, part c.

[42] See PEG's response to EB-2019-0082, L1, Tab 1, Schedule 9, part a.

every utility in the sample, including Hydro One, when levelizing the capital asset price. This is the consistent approach and given that Hydro One serves many remote areas of Ontario, where capital prices could be higher than in Toronto, this is a good approximation of Hydro One's capital price levelization.[43]

2. PEG mentions that PSE applied the capital price levelization in the wrong year. Like the prior concern, PEG also levelized in the exact same year as PSE, which is 2012.[44] This is inconsequential to the result.

3. PEG discusses the 1.65 declining balance parameter used by PSE to formulate the transmission depreciation rate. This is, again, inconsequential to the benchmarking result. PEG used the same approach as PSE in their HOSSM research.

4. PEG states that PSE only used transmission plant in calculating the capital price and quantity trends, even though a material portion of assets are recorded as general plant. The approach that PSE undertook enables a consistent approach between Hydro One and the U.S. sample. In contrast, PEG's approach is not consistent and treats Hydro One differently than the rest of the sample, due to Hydro One's inability to break out transmission and general plant. We do not dwell on this inconsistency in our critiques of PEG in Section 2 because we believe this is an inconsequential inconsistency.

4 Reply to PEG's Plan Design Comments

In this section we provide a reply to some of PEG's plan design comments. We did not investigate the actual capital needs of the Company, and do not know if the proposed capital spending amounts are necessary. From a high-level perspective, what we do know of the capital spending plan is this: at the proposed capital spending levels, the company's total costs during the 2020-2022 period are 32% below the expected levels. This is PSE's result, and PEG's result would be close, if the two PEG flaws discussed in Section 2 are corrected.

This benchmarking result should not be ignored when contemplating whether the capital needs of the company are at the proper amounts. A finding of 32% below cost is a strong one and provides evidence that the company is producing cost savings relative to the industry, but also may need to increase spending for a time relative to the industry.

PEG recognized the need for capital spending in the electric transmission industry and how the industry has changed over time in work for the Edison Electric Institute (EEI), which is the US investor-owned electric utility industry's trade group. In a 2015 EEI paper that PEG authored (*Alternative Regulation for Emerging Utility Challenges),* on p. 47 PEG recognized the need for increased investments in the transmission industry to help tackle these emerging challenges in the utility industry. PEG wrote that investments in the power transmission industry are "urgently needed investments." However, PEG's suggestions on reducing the capital spending proposal of

[43] In PEG's response to EB-2019-0082, L1, Tab 1, Schedule 9, part b PEG suggests there is evidence the construction costs will be lower than Toronto. However, PEG cites indexes for a number of relatively large municipalities but ignore the fact that Hydro One serves many remote areas that likely increase construction costs.

[44] See PEG's response to EB-2019-0082, L1, Tab 1, Schedule 4, part e.

M1-HON-9

Reference: Exhibit M1, page 24

Preamble: PEG states that only Toronto values were used to levelize the Company's construction cost index, even though much of the transmission system is located far from Toronto.

Interrogatories:

a) What city values did PEG used in their research to levelize the construction costs for Hydro One?

b) Does PEG believe that it may be possible that construction costs for Hydro One are higher than those in the Toronto index, due to the company serving relatively remote and hard to reach areas?

Response to HON-9: The following response was provided by PEG.

a) PEG followed PSE's construction cost levelization method using data provided by PSE which used Toronto as the only city for HON. Despite our stated concerns, we did not prioritize making a change to this part of the work.

b) No. Evidence suggests that they will be lower. Below is a table with construction cost data from the 2012 RSMeans book for every available city in Ontario. It can be seen that Toronto has the highest value. Therefore, if PEG did use a population-weighted average value as they have done in many prior studies, it would result in a lower value for HON and a lower cost performance score.

Table HON-9

RSMeans City Cost Indexes
(2012 Book, 2010 Values)

Ontario	
City	**Total Weighted Average Value**
Toronto	112.3
Sarnia	110.5
Brantford	110.4
Hamilton	109.4
Kingston	109.2
Barrie	109.1
Cornwall	108.7
Oshawa	108.7
Ottawa	108.7
Peterborough	108.6
Owen Sound	108.3
Timmins	107.8
London	107.8
North Bay	107.8
Sault Ste Marie	104.6
Kitchener	103.4
Thunder Bay	103.0
St. Catharines	102.8
Sudbury	102.7
Windsor	102.4