Response to PEG's Commentary on HQT's MRI Evidence

PREPARED BY

Agustin J. Ros
Sai Shetty

PREPARED FOR

Hydro-Quebec TransÉnergie

NOVEMBER 29, 2021

Brattle

NOTICE

- This report was prepared for Hydro-Quebec TransÉnergie, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Introduction and Recommendations

A. Background on studies

In 2019 (D-2019-060), the Régie de l'énergie ("the Régie") requested that HQT prepare *l'étude de productive multifactorielle* (multi-factor productivity or "MFP") in the first three years of the *Mécanismes de Réglementation Incitative* ("MRI"). The Régie indicated that the MFP could be used potentially to reset HQT's current X-factor—that applies only to *charges nettes d'exploitation* (net operating expenses)—in year four of the plan or in a subsequent plan and that could apply to both HQT's operating expenses as well as its capital expenses. In its decision, the Régie also requested a statistical benchmarking or econometric cost comparison study to assist in establishing the Stretch factor ("S-factor").

Brattle submitted a report on February 19, 2021 that included a total factor productivity ("TFP") study—with resultant operation and maintenance ("O&M") and capital Partial Factor Productivity ("PFP") results—and an econometric cost comparison study ("cost-benchmarking").[1] Pacific Economics Group ("PEG") submitted a report dated February 15, 2021 that included TFP, PFP O&M and PFP capital and an econometric cost-benchmarking study.[2] PEG filed a second report on November 8, 2021 that provided commentary on Brattle's Direct Report.[3]

1. Brattle studies

– **Productivity Study**

We used FERC Form 1 data and a sample of 74 U.S. utilities that provided transmission services and calculated TFP as well as PFP O&M and PFP capital over the period 1995 to 2019. Table 1 below summarizes our results. The results represent our *base case* and reflect a number of methodological choices and assumptions that we made and that we discussed in detail in our Direct Report.

---

[1] *See*, Total Factor Productivity and the X-factor for Hydro-Quebec TransÉnergie, February 19, 2021, ("Direct Report"). We refiled this report on July 30, 2021.

[2] *See*, Transmission Productivity and Benchmarking Study, February 15, 2021 ("PEG Direct Report"). PEG refiled this report also on July 30, 2021.

[3] *See*, PEG Commentary on Hydro-Quebe's *MRI* Evidence, November 8, 2021, ("PEG Commentary Report").

TABLE 1: SUMMARY OF BRATTLE PRODUCTIVITY RESULTS

Year	Growth of TFP Index	Growth of PFP O&M (1995 - 2019)	Growth of PFP Capital (1995-2019)
1995 - 2019	-1.04%	-3.38%	-0.05%
2000 - 2019	-1.50%	-3.28%	-0.64%
2002 - 2019	-1.57%	-3.29%	-0.75%
2005 - 2019	-1.69%	-3.09%	-0.97%
2010 - 2019	-1.97%	-3.13%	-1.43%

Source: Brattle TFP Model

In our Direct Report, we also discussed how we complied with the Régie's General and Specific Guidelines in D-2019-060 pertaining to the TFP and econometric cost comparison studies. Two in particular were:

- The detailed results of the calculations underlying the studies must be filed in a spreadsheet and be sufficiently documented to allow the Régie and stakeholders to understand them, validate them and, if necessary, reproduce them,[4] and;
- All the assumptions, methodological choices and the calibration of the models, inputs, outputs and calculations must be documented and presented in order to understand the impact of using an assumption, a methodological choice, an input, an output or a calculation that can significantly vary the results.[5]

In order to comply with these two guidelines, we constructed an Excel-based, transparent, dynamic and user-friendly TFP model. The model contains all our underlying data with all live formulas to permit a user to understand, trace, validate and reproduce the results. The model permits the user to audit and validate our results and to conduct sensitivity analysis such as selecting different companies in the sample, altering our base case methodologies and assumptions and ascertaining the impact on results. In our Direct Report, we presented sensitivity analyses on the impact of changing the key assumptions in our study, as requested by the Régie, including examining the impact of different capital specifications, asset lives, output measures and inclusion or exclusion of certain costs.

Our results showed an X-factor of -1.04 percent for a MRI consisting of capital and operating expenses and an X-factor of -3.38 percent for a MRI on operating expenses only. This is for an I-X formula where I is a measure of input price inflation.

– Econometric Cost Comparison Study

4 D-2020-28 ¶ 92.

5 D-2020-28 ¶ 92.

We conducted an econometric cost-benchmarking study using the same 74 companies that we used in our TFP study adding HQT to our sample. To perform the econometric cost comparison, HQT provided us with financial and operational data comparable to the data for the U.S. transmission companies published in FERC Form 1. Our econometric cost comparison analysis begins in 2001, as that was the first year that HQT data were available. We developed an econometric model that explains the total costs of a utility—the dependent variable—as a function of a set of independent variables that we believe affect a utility's total costs. Given the fact that we have a "panel" of data—*i.e.*, a dataset consisting of observations on the same companies over the entire period—we considered two common estimators used with panel data—the "fixed-effects" and the "random effects" models. We use the estimated econometric model to compare HQT's cost performance *vis-à-vis* the industry. Specifically, we used the model's estimated parameters to predict HQT costs and to compare the predicted costs to HQT actual costs. We calculate a percentage difference and summarize how HQT fares over the period.

We concluded that over the 1995 to 2019 period, HQT's actual costs were below the model's predicted costs, always within a +/- 10% range. Based on this analysis, we concluded that HQT is not a poor performer, its cost performance lies around the mean values for the sample of companies. With respect to the Stretch Factor, we cautioned against mechanical use of econometric cost comparison analysis for setting the stretch factor, as it cannot be a complete substitute for what we believe is ultimately an exercise based on judgement as well as regulatory precedence. Based on the overall evidence, including S-factor decisions in other jurisdictions, we concluded that that 0.10 to 0.30 percent is a reasonable range for the S-factor for an MRI plan that resets the X-factor in year four of the plan, and that could apply to both HQT's operating expenses as well as its capital expenses.

2. PEG studies

– **Productivity Study**

PEG used FERC Form 1 data and a sample of 51 U.S. utilities that provided transmission services and calculated TFP as well as PFP O&M and PFP capital over the period 1996 to 2019. Table 2 summarizes PEG's results. The results represent PEG's methodological choices and assumptions, many of which differ from Brattle's, and which we discuss in our Direct Report and throughout this report. Neither PEG's Direct Report nor its Commentary Report include sensitivity analyses on the impact of changing key assumptions on its study. Its TFP model lacked the ability to easily trace, validate, and reproduce the TFP results without substantial effort and work and at the risk of making incorrect changes to the model that would have unknown impacts and possibly invalidate the sensitivity analysis. For this reason, throughout this report we use the Brattle TFP model to perform sensitivity analysis on PEG's methodology and TFP analysis.[6]

[6] In responses to Brattle data requests, we acknowledge that PEG was reasonably responsive to our requests including performing sensitivity analyzes on its model.

TABLE 2: SUMMARY OF PEG PRODUCTIVITY RESULTS

Period	MFP	O&M	Transmission Capital	Allocated General Plant
1996 - 2019 (24 Years)	-0.62%	-0.68%	-0.46%	-1.29%
2005 - 2019 (15 Years)	-2.26%	-1.74%	-2.16%	-1.80%

Source: PEG Direct Report, February 15, 2021

- **Econometric cost-benchmarking**

PEG conducted an econometric cost-benchmarking study using 48 companies. PEG estimated an econometric model using pooled ordinary least squares ("OLS"). In marked contrast to Brattle's results, PEG's benchmarking results from the Direct Report showed that for the most recent three-year period of 2017 to 2019, HQT's actual costs are considerably higher than predicted by its models for all three cost categories leading to the conclusion that HQT is a very poor cost performer. Based on these results and the approach adopted by the Ontario Energy Board ("OEB") for stretch factor determination, PEG proposed a stretch factor of at least 0.60% for the current CNE revenue cap and a stretch factor of at least 0.60% for any future comprehensive revenue cap based on total costs. PEG also recommends a stretch factor adder of 0.10% should the Régie base the X-factor on productivity results for the full sample period and an adder of 0.30% if productivity results for the most recent 15-year period are considered.

B. Summary of Brattle Concerns with PEG studies and Responses to Commentaries

1. Productivity

PEG's TFP study has flaws, as does its "Alternative Productivity Runs using Brattle Data" discussed in PEG's Commentary Report. In this report, we highlight and explain the concerns we have about PEG's empirical productivity research and respond to PEG's critique of our work in its Commentary Report. Among the most relevant concerns and responses are the following.

- ***Sample of companies***: PEG's exclusion of a significant number of transmission companies resulted in a material upward bias in measured productivity. Brattle used 74 U.S. companies, while PEG used 51. Among the companies that PEG excluded was Pacific Gas and Electric ("PG&E")—the largest company in our sample—and Georgia Power, within the top five in our sample. PEG also excluded Central Maine Power, a company that borders HQT and which PEG described as having similar business conditions as HQT.

- ***Transmission O&M expenses***: PEG excluded three FERC transmission O&M accounts representing more than *50 percent* of total transmission O&M expenses in its TFP study, resulting in a material upward bias in measured productivity. The excluded expenses are part of the costs that U.S. companies and HQT incur to provide transmission services. The FERC utilizes expenses in the three excluded accounts on a routine basis to establish just and reasonable transmission service rates. We performed simple statistical analysis on the excluded expenses and did not find evidence supporting PEG's reasons for excluding the accounts.

- ***Capital benchmark:*** PEG's lower sample of companies in its TFP study was due in part to its desire to use a 1964 capital benchmark, rather than 1988 using readily available data. We believe that any improvement in accuracy from an older capital benchmark is outweighed by the large bias from having a smaller sample in the TFP study. In addition, for the capital benchmark denominator we continue to recommend the use of a weighted average of an historical new construction price index to deflate the capital benchmark, with more weight given to recent years. Calculation of the capital benchmark is inexact and the assumptions requiring use of simple average are unlikely to be met.

- ***Common costs***: Our sensitivity analysis in our Direct Report showed that our *TFP growth* results are materially affected by our choice of excluding common costs—administrative and general ("A&G") and general plant. However, our PFP O&M results changed little with inclusion of common costs and the inclusion or exclusion of common costs does not affect our econometric cost-benchmarking conclusions. Unlike transmission O&M expenses excluded in PEG's study, common costs are by definition, not transmission related and cannot be directly assigned as such. TFP studies, as ours, can be sensitive to the methodology used to include common costs and thereby lessening the validity of the studies.

- ***Output***: We use peak demand for our productivity study rather than ratcheted peak demand, as the latter does not correspond with the actual peak demand observed in a given year. It is not consistent with the physical unit of output observed and produced in a given year, given the input services—*i.e.*, capital, labor and MR&S services—in that year. In addition, using ratcheted peak demand artificially constrains the output growth to be no lower than zero in any given year.

- **Additional comments**: Additional concerns we have include PEG using the same rate of return for each company in a given year. Rate of return is a key component of the capital price and PEG's assumption prevents the level of a company's rate of return to vary among companies in each year of the sample period, and distorting the capital price variation among the companies. PEG's model also ignores accelerated depreciation and taxes, which further distort capital prices of the sampled companies.

2. Econometric cost-benchmarking

PEG's econometric cost-benchmarking analysis is seriously flawed and unreliable, as is its "Alternative Benchmarking Runs Using Brattle Data" discussed in PEG's Commentary Report. In this report, we highlight and explain the concerns we have about PEG's empirical benchmarking research and respond to PEG's critique of our work in its Commentary Report. Among the most relevant econometric concerns and responses are the following.

- ***PEG's econometric model***: PEG's conclusion that HQT is a very poor cost performer relies on econometric models that have a fundamental methodological flaw. Its models fail to control for those *unobservable* economic and business condition factors that are unique to HQT—*e.g.*, unique logistical challenges, towers sometimes housed in structures due to cold winters throughout territory, being a Crown corporation, *etc*. PEG's approach counts all these unique HQT characteristics as cost inefficiencies while our approach does not. This is the main explanation for the differences between Brattle and PEG's cost-benchmarking results.

- Statistical tests that we performed on PEG's data reject the use of its econometric models, pooled OLS. Using PEG's data and the correct econometric model results in HQT no longer being a poor cost performer as its actual costs are below the model's prediction.

- ***Brattle's econometric model***: We utilize a fixed-effects ("FE") model for our econometric cost-benchmarking analysis and for predicting HQT's costs. A FE estimator is very well suited to the econometric problem at hand because it controls for HQT's unique factors when benchmarking HQT's costs. Statistical tests performed on our data confirm that a FE model is required and that pooled OLS would result in unreliable cost benchmarking. A literature review supports the general use of panel data models—like FE and Random Effects ("RE")—in empirical cost-benchmarking analysis.

- In responses to data requests from intervenors, PEG suggests that the correct way to implement the FE for cost benchmarking in this case is to *ignore* HQT's unique factors when using the model to predict HQT's costs. This approach assumes that HQT's unique factors are *endogenous* and under the control of management. PEG's cost benchmarking results suggests that with different management HQT could lower its costs by *more than 50 percent* just to be an average cost performer. We do not believe this is a credible result and is evidence of the flaw in PEG's cost-benchmarking methodology.

- PEG does not discuss the basis of such large cost inefficiencies on the part of HQT nor how different management would be able to change so dramatically the cost impact of HQT's unique features. Nor does it discuss the role of regulation, and why the regulatory regime has permitted and not corrected for such large inefficiencies throughout the years.

- ***Sensitivities on cost benchmarking***: Our cost-benchmarking conclusions are robust to different specifications and TFP assumptions, including different output measures (*i.e.*, use of transmission system peak demand), removal of O&M accounts that PEG excludes, utilizing a geometric decay capital specification, and a translog econometric specification.

- **Additional comments on PEG's econometric model**: When predicting HQT's costs, PEG uses *Hydro One's* scores for forestation and construction standard index from a recent OEB performance regulation proceeding. It is unlikely that scores for HQT and Hydro One are the same, thus further biasing the cost benchmarking analysis.

- ***PEG's recommended S-factor "adder"***: Based on its cost-benchmarking analysis and the OEB methodology, PEG recommends an S-factor of 0.6 *plus* an "adder" ranging anywhere from 0.1 to 0.3. PEG provides insufficient quantitative evidence on the adder and how to translate characteristics of specific regulatory regimes into specific stretch factors.

C. Recommendations

1. X-factor and S-factors

- **X-factor**

Based upon our productivity analysis in our Direct Report and for the reasons we discuss in this report, we maintain our X-factor recommendations from our Direct Report. Our results show an X-factor of -1.04 percent for a MRI consisting of capital and operating expenses and an X-factor of -3.38 percent for a MRI on operating expenses only. This is for an I-X formula where I is a measure of input price inflation.

- **S-factor**

Based upon our review of past regulatory decisions on the stretch factor adopted by regulators for a transmission or electricity distribution PBR plan discussed in our Direct Report, as well as the econometric cost comparison work we performed in the Direct Report and in this report, we maintain our S-factor recommendation from our Direct Report. Our econometric analysis in our Direct Report and in this report contradict PEG's conclusion that HQT is a very poor cost performer. Based upon our analysis, HQT's costs tended to be fairly close to the costs predicted by the econometric model. We continue to believe that 0.10 to 0.30 percent is a reasonable range for the S-factor for an MRI plan that resets the X-factor in year four of the plan or in a plan, and that could apply to both HQT's operating expenses as well as its capital expenses.

2. PEG's alternative productivity and benchmarking runs using Brattle data

– **Alternative productivity runs using Brattle data**

For the reasons we describe in this report, we do not agree with the changes that PEG makes to our TFP model and we discuss the reasons why in this report.

– **Alternative benchmarking runs using Brattle data**

As part of PEG's alternative benchmarking runs using Brattle data in its Commentary Report, PEG "upgrades" the capital benchmark, removes transmission expenses by others, and removes six companies. PEG then estimates econometric models using Fixed Effects, Random Effects and OLS. Even with these "upgrades" which we dispute, when PEG estimates Fixed Effects models, its conclusion that HQT is a poor cost performer no longer holds. Under the Fixed Effects models, PEG reaches the same conclusion we did in our cost-benchmarking analysis—HQT is not a poor cost performer, rather HQT's costs tended to be fairly close to the costs predicted by the econometric models.[7] When PEG estimates the "upgraded" data using OLS it shows HQT is a poor cost performer. However, for the reasons we discuss at length in this report, the use of OLS to estimate econometric models for the data at hand is a fundamental methodological flaw.

II. Productivity: Concerns with PEG's Study and Responses

A. Sample companies

1. Exclusion of transmission companies

Our TFP study utilized FERC Form 1 data for 74 U.S. electricity transmission companies. We obtained our data from S&P Global (formerly SNL Financial). In our Direct Report (Section V. B.), we outlined our sample selection methodology and process, which consisted of selecting as many companies as possible governed by data constraints. We stated that since productivity growth exhibits significant volatility at

[7] After criticizing the use of fixed effects models *per se* in cost benchmarking in its Commentary Report, in responses to questions from Brattle and other intervenors, PEG suggests that the proper way to use fixed effects for predictions is to ignore HQT's unique fixed effects because they reflect pure inefficiencies. We disagree and discuss the reasons why in Section III.A.

the individual firm level, selecting as large a sample as possible helps reduce the volatility.[8] Moreover, we commented that HQT is a very large company, larger than any in our FERC database, and restricting the sample to companies closer to HQT's size would leave few companies.[9] An additional reason to include as many companies as possible in the sample is to minimize the impact of any potential data issues in the underlying FERC Form 1 data, such as occasional errors in entering data or assigning costs to different accounts. Using a larger sample of companies to estimate TFP minimizes the impact these types of data issues can have on measured TFP growth.

For our sample selection process, we began with a population of 142 U.S. electricity transmission companies. For the reasons we discussed in Appendix I of our Direct Report, our sample size of US transmission companies for our productivity and econometric cost-benchmarking study was 74. Among some of the reasons for excluding 68 out of the 142 companies in our sample were: (1) not having complete data,[10] (2) mergers that make it more difficult to have a comparable data series for the merged company,[11] and (3) anomalous data.[12] In addition, in some instances we made minor adjustments to the data to preserve the company in our sample.[13] We have logged all these reasons and highlighted all the minor adjustments we made to the data in Appendix I of our Direct Report.

PEG's TFP study utilizes FERC Form 1 data for 51 U.S. electric utilities. Brattle included 27 U.S. electricity transmission companies in our sample that PEG does not include—see Table 3 below. In data response Brattle 1.1, PEG indicated that there were 129 reported companies that reported both miles of transmission lines and peak demand, and that presumably could be considered in the TFP study. In its Direct Report (p. 67), PEG indicated that mergers and acquisitions limited the sample size, as did missing or implausible data but it did not provide a company-by-company justification for the exclusions of many of the 129 potential companies nor did it document adjustments made to the original data. PEG states in its Commentary Report (p. 30), that "companies used in productivity or benchmarking studies typically have a modest effect on the results." As we show in the next section, this statement is incorrect.

---

[8] In response to Régie 11.1.2, we showed that the standard deviation of TFP growth for a subset of 5, 10, and 15 companies was much higher than the standard deviation of TFP growth for our entire sample of 74 companies.

[9] See also our response to the Régie 11.1.

[10] As an example, for Black Hills Colorado Electric Inc. there was no data prior to 2008.

[11] As an example, AEP Texas Central Company and AEP Texas North Company merged into AEP Texas in 2016 after which data is not reported separately for the two entities.

[12] As an example, Consumers Energy reported negative O&M costs in 2002 and no transmission line length in between 2001 and 2015.

[13] As an example, transmission line length for Baltimore Gas and Electric Company was unavailable for 1996, so we imputed its value using the 1995 and 1997 values. In addition, we imputed the 1994 transmission line length for Dayton Power and Light Company given that its reported value for 1994 was inconsistent with the 1995 value.

TABLE 3: TRANSMISSION COMPANIES IN BRATTLE'S SAMPLE AND EXCUDED IN PEG'S SAMPLE

Company Name	2019 Tranmission Length (Miles)	2019 System Peak (MW)	Total Real Costs Used in Econometric Model ($000)
Black Hills Power, Inc.	773	420	$19,976
Central Maine Power Company	2,906	1,616	$98,367
Cleveland Electric Illuminating Company	1,232	4,188	$163,097
Dayton Power and Light Company	1,711	3,246	$73,371
Entergy Arkansas, LLC	5,188	4,513	$130,509
Entergy Mississippi, LLC	3,132	2,994	$65,963
Entergy New Orleans, LLC	164	1,155	$14,911
Georgia Power Company	12,417	16,572	$286,560
Green Mountain Power Corporation	1,010	612	$32,178
MDU Resources Group Inc.	3,384	564	$25,415
Nevada Power Company	1,901	5,611	$73,262
Northern Indiana Public Service Company	1,230	3,149	$93,247
Northern States Power Company - WI	2,679	1,305	$62,064
NSTAR Electric Company	1,525	4,449	$206,125
Ohio Valley Electric Corporation	426	1,021	$8,520
Otter Tail Corporation	6,191	924	$27,276
Pacific Gas and Electric Company	36,659	18,731	$447,528
Portland General Electric Company	1,574	3,765	$91,808
Potomac Edison Company	2,076	3,609	$37,812
PPL Electric Utilities Corporation	4,500	7,729	$160,872
Public Service Company of New Hampshire	1,041	1,609	$77,049
Public Service Company of New Mexico	3,140	1,937	$62,542
Public Service Company of Oklahoma	3,123	4,104	$80,397
Puget Sound Energy, Inc.	2,610	4,498	$112,576
Sierra Pacific Power Company	2,333	1,808	$63,936
Southwestern Electric Power Company	4,170	4,727	$100,855
United Illuminating Company	112	1,216	$76,122

Source: Brattle TFP Model and S&P Global Data.

PEG described its sample selection methodology in data response 1.2 and explained it was based upon recent Ontario Energy Board proceedings and the sample selection methodology of Hydro One's witness in that proceeding. In addition, it seems likely that an important reason for PEG's much lower sample size is its preference to utilize only those companies for which it has calculated the benchmarking capital for 1964.[14] We do not believe that this is a reasonable tradeoff. The emphasis on an older benchmark capital and the resulting loss of a significant number of companies is not justified, as any marginal benefit in using an older benchmark capital is uncertain and not likely to be worth the substantial sample selection bias introduced into the analysis.

14 In Brattle questions 1.3.4, 1.3.7 and 1.3.8 we asked whether PEG has calculated the 1964 benchmark capital for Pacific Gas & Electric, Georgia Power and the remaining companies that were in Brattle's study but not in PEG's study. PEG did not respond to these questions.

As Table 3 above shows, PEG's smaller sample of companies does not include two large companies included in our sample, Pacific Gas and Electric as well as Georgia Power. PG&E is the largest company we have in our database based upon combined peak demand and transmission length, while Georgia Power ranks fourth highest.[15] PG&E is the only company in our sample whose transmission line length is comparable to HQT, with the second company in our sample having much lower line length compared to HQT. Central Maine Power is another company in our sample but not in PEG's sample even though PEG characterized the company as facing "business conditions that are similar to HQT's" (Direct Report p. 59).

PEG provided the following justification for excluding PG&E from its study (PEG response to Brattle 1.3.4):

> The transmission system of PG&E suffered severe wildfire damage in recent years, particularly 2018. PEG determined that the recent experience of PG&E is not characteristic of the normal operations of a power transmission company. Since the cost impact of these events show up in the last year of the sample (2019), productivity trends calculated using these data would be biased downward because the end point of the trend was very atypical. Because PG&E is a large company, its inclusion in the productivity and benchmarking work would materially bias results. When additional years of data reflecting more typical operating conditions are available, PG&E may be reincluded in PEG's cost research.

We disagree. Wildfires did not begin in 2018, nor will they likely disappear in future years, as evidenced by their continuation in the years since 2018. Wildfires and the potential for wildfires affect all utilities in California (and the Pacific Northwest) and a search reveals that the 10 largest wildfires in California history occurred throughout the period of our sample, 1995 to 2019 and not just in PG&E's territory.[16] Wildfires have also been common in other areas of the country as well and the costs of preparing and dealing with wildfires are appropriately included in TFP studies. In our TFP study, we do not treat the effects of wildfires any differently than the effects of other environmental and natural disasters. We do not exclude companies like Florida Power and Light ("FP&L") because its service territory has experienced significant hurricanes, nor do we exclude Central Maine Power because its territory is prone to ice storms, or utilities in Kansas because of tornados. In addition, to the extent that warming weather and environmental changes in more recent years have been more pronounced and impactful on transmission costs than in the past—and to the extent such changes reflect a growing trend in such activity that will likely continue—removing a company from the sample that is large and affected by such changes will bias the TFP results and diminish their use as a good estimate of forward-looking TFP,

15 See response to Régie 11.1.1.

16 See, https://www.frontlinewildfire.com/california-wildfires-history-statistics/.

which is used for the X-factor. Lastly, we note that in its 2018 study before the Ontario Energy Board, PEG also excluded PG&E from its sample, even though it sample period ended in 2016, two years *before* the large 2018 wildfire.

PEG indicated in its Commentary Report (p. 30), that “[w]hile some of the extra Brattle companies may have sound data, others have problematic data.” PEG provides no examples or evidence of Brattle’s “problematic data” even though it had access to our Appendix I in our Direct Report and to our underlying data. PEG raises concerns about our sample containing companies “that have not been corrected for the effect of mergers.” We indicted in our Direct Report (p. 44) that we removed some utilities due to data issues regarding mergers and acquisitions and we cited the example of the Ameren Illinois companies. As mentioned above, we also removed AEP Texas due to data not being available for the merged companies post-merger.

In its Commentary Report PEG objected to our inclusion of Georgia Power due to merger concerns but provides no specific example of the concern, which years and accounts are problematic and whether PEG’s solution of excluding the company is justified. In response to Brattle question 1.3.7, PEG indicated that Georgia Power was involved in a merger with Savanah Electric and Power. The merger in question occurred in 2005/06 and Savanah Electric and Power was a small utility at the time of the merger compared to Georgia Power[17]. An examination of Georgia Power’s output, capital accounts and O&M expenses did not reveal any major discrepancies that would justify the exclusion of such a large company operating in a non-ISO environment, nor the exclusion of NSTAR, another company that PEG excluded because of merger concerns.[18]

The one concrete evidence PEG provided on merger problems is for Green Mountain Power. PEG spends almost a paragraph in its Rebuttal Report (p. 30) describing its view of why recent mergers make it difficult to include Green Mountain Power, one of the smallest companies in our sample. We answered in response to PEG question 4.6 that removal of Green Mountain Power from our sample has practically no discernable effect on our results as our TFP growth remains at -1.04% and only affect results beyond the second digit.

[17] In 2006, Savannah Electric and Power’s total transmission O&M was just 5.31% of Georgia Power’s, according to S&P Global data.

[18] In response to Brattle question 1.3.7, PEG indicated that it did not include Georgia Power because “[i]t was not included in Mr. Fenrick’s work *presumably* because the appropriate adjustments to the historical data needed to include the company was not done.” [emphasis added]. A review of Georgia Power data for the period 2005/06 reveals what looks like merger-related impacts on *both* its costs and outputs.

2. Excluding companies resulted in an upward bias in productivity

PEG's exclusion of a significant number of transmission companies resulted in an upward bias in measured TFP and PFP O&M. We ran a sensitivity utilizing our TFP model and using the 47 companies that overlap in our and PEG's sample. We set all assumptions to our base case. Table 4 below shows higher TFP growth of -0.72% when utilizing the smaller sample of 47 companies compared to our base case of -1.04% when utilizing our 74 companies. The upward bias in PFP O&M growth was even higher, at -2.57% with the sample of 47 companies, compared to -3.38% with the sample of 74 companies. The upward bias in measured TFP and PFP O&M due to PEG's smaller sample was 0.32% and 0.81%, respectively during the entire period.

TABLE 4: TFP RESULTS – BRATTLE METHODOLOGY USING PEG SAMPLE COMPANIES

Model	TFP Growth (1995 - 2019)	Growth of PFP O&M (1995 - 2019)	Growth of PFP Capital (1995-2019)
Brattle Base Case (74)	-1.04%	-3.38%	-0.05%
Brattle Base Case using PEG Sample Companies (47)	-0.72%	-2.57%	0.02%
Difference due to PEG sample selection bias	**0.32%**	**0.81%**	**0.07%**

Source: Brattle TFP Model; Note: Using 47 companies that are common to the Brattle TFP sample and PEG sample.

We also performed a sensitivity analysis using PEG's base case to determine the sample selection bias and to determine whether we can rule out the conclusions above being the result of our methodology. First, we estimated TFP growth using the 74 companies in our sample but selecting PEG's base case scenarios—*i.e.*, geometric decay, exclusion of a majority of transmission O&M expenses, inclusion of general costs, *etc*. We then estimated TFP growth under the same assumptions but using the 47 companies that overlap in the Brattle and PEG sample. The results in Table 5 below confirm our finding from above that PEG's smaller sample size resulted in an upward bias of TFP growth, with the upward bias being higher. Specifically, the upward bias in measured TFP and PFP O&M growth due to PEG's smaller sample and using PEG's base case was 0.35% and 0.98%, respectively during the entire period.

TABLE 5: TFP RESULTS – PEG METHODOLOGY ON BRATTLE AND PEG'S SAMPLES

Model	TFP Growth (1995 - 2019)	Growth of PFP O&M (1995 - 2019)	Growth of PFP Capital (1995-2019)
PEG Base Case with Brattle Companies (74)	-1.22%	-0.94%	-0.72%
PEG Base Case with PEG Companies (47)	-0.87%	0.04%	-0.70%
Difference due to PEG sample selection bias	**0.35%**	**0.98%**	**0.02%**

Source: Brattle TFP Model; Note: The "PEG Base Case" referenced in the table uses the Brattle TFP model with the sample of 47 companies that are common to the Brattle and PEG sample. It also includes the assumptions used by PEG to model productivity for the US sample – geometric decay for capital, output weights, exclusion of transmission accounts 561, 565, and 566, inclusion of share of A&G and general plant, ratcheted peak demand and asset service life.

B. Transmission O&M expenses

1. Exclusion of more than 50 percent of transmission O&M expenses

PEG excluded close to 6*0 percent* of FERC Form 1 transmission O&M expenses from its transmission productivity study (see Table 6 below) which led to a significant upward bias in measured TFP growth. PEG excluded *all* expenses in account 561.1-561.8, *all* expenses in account 566 (miscellaneous transmission expenses) and *all* expenses in account 565 (transmission of electricity by others).

TABLE 6: PERCENTAGE OF FERC TRANSMISSION O&M EXPENSES EXCLUDED BY PEG

Company List	Account 565: Transmission of Electricity By Others Share of O&M	Accounts 566: Miscellaneous Transmission Expenses Share of O&M	Accounts 561.1-561.8 Share of O&M	All other (residual) transmission expenses	% of O&M Expenses Excluded
Brattle Sample	34.87%	17.18%	10.74%	37.21%	0.00%
PEG Sample	25.66%	21.03%	12.59%	40.72%	59.28%

Source: Brattle TFP Model; PEG sample includes the 47 companies that are common to the Brattle and PEG samples.

PEG emphasized that the exclusion of the three accounts is primarily due to data issues—as opposed to arguing that the categories are not part of the cost of providing transmission services. Given that the excluded expenses are (1) part of the cost incurred to provide transmission services and (2) tend to grow faster than other categories, as we show below, such exclusion biases measured TFP upward. Table 7 below shows that all three excluded accounts that PEG removed grew more rapidly than the remaining ("residual") O&M expenses, resulting in an upward bias in measured TFP and PFP O&M growth. In response to Brattle question 2.3, PEG indicated that the average annual growth rate of the included O&M costs over the full sample period was 3.56% while for the excluded items it was 8.32%.

TABLE 7: GROWTH RATE OF TRANSMISSION O&M EXPENSES EXLCUDED BY PEG

Company List	Account 565: Transmission of Electricity By Others	Accounts 566: Miscellaneous Transmission Expenses	Accounts 561.1-561.8	All other (residual) transmission O&M expenses
Brattle Sample	11.26%	13.13%	10.02%	5.12%
PEG Sample	11.93%	14.89%	8.49%	3.68%

Source: Brattle TFP Model; Values are summations of all spending by utilities per account, weighting larger utilities more heavily.

We have re-run our TFP model to remove the three O&M accounts that PEG excluded to determine the upward bias in measured productivity for our sample. Table 8 below shows the results. The removal of the three accounts results in a significant upward bias in measured TFP and PFP O&M growth.

TABLE 8: UPWAD BIAS IN MEASURED PRODUCTIVITY FROM REMOVAL OF O&M ACCOUNTS

Model	TFP Growth (1995 - 2019)	Growth of PFP O&M (1995 - 2019)
Brattle Base Model	-1.04%	-3.38%
Removing Load Dispatching (Act: 561)	-0.90%	-2.98%
Removing Transmission by Others (Act: 565)	-0.64%	-2.32%
Removing Miscellaneous Transmission Expense (Act: 566)	-0.86%	-3.00%
Removing All Three Accounts	-0.34%	-1.20%

Source: Brattle TFP Model

We asked PEG to re-run its TFP model including the omitted expenses. In response to Brattle question 2.4, PEG indicated that when it includes the expenses in three accounts measured TFP decreased from -0.64% to -1.12% and PFP O&M decreased from -0.68% to -2.38% over the 1996-2019.

2. Insufficient evidence provided for the exclusions

PEG provides two principal reasons in its Direct Report (p. 69), for not including the three FERC accounts—account 561.1-561.8, account 566 (miscellaneous transmission expenses) and account 565 (transmission of electricity by others)—in its productivity study. PEG states:

> "We excluded some categories of transmission CNE from our productivity trend calculations out of concern that 1) they were sensitive to the restructuring of the transmission industry and 2) this restructuring is of limited relevance to an MRI for HQT."

The restructuring that PEG refers to is the growth of ISO membership between 1996 and 2005. PEG includes a section in its Direct Report (pp. 63-65) entitled *ISO Complications*. The subsection contains PEG's rationale for excluding the three FERC accounts—the growth of ISOs has led to differences in how companies report costs and that "[c]hanges in how costs were reported *can* affect research results." [Emphasis added]

In our opinion, excluding a large amount of transmission O&M expenses from a transmission TFP study requires convincing and compelling evidence. A review of the specific reasons in its Direct and Commentary Reports for excluding the three FERC accounts reveals that PEG provided insufficient evidence to support its decision to exclude the accounts. Perfection in the FERC Form 1 data is not a requirement for the TFP study as we can accept some amount of data imprecision and inconsistencies in the way companies report their data for *any* account. The following excerpts are typical of the type of evidence that PEG provides to support its exclusion of more than 50% of FERC Form 1 transmission O&M expenses from its productivity study. PEG Direct Report pp 64-65:

> "The new data guidelines occasioned by FERC Order 668 did not occur until many California, Midwestern, New York, and New England utilities had been ISO members for several years. This has produced some shifts in where ISO costs are reported. As one example, a utility *might have initially* reported certain ISO costs as transmission by others expenses (which are excluded from our calculations) and then reported them as dispatching expenses." [Emphasis added]

PEG Direct Report p. 65:

> "Utilities *seem to have* reported ISO costs incurred before FERC Order 668 inconsistently, with some reporting them as transmission by others expenses and others reporting them as miscellaneous transmission expenses." [Emphasis added]

PEG Direct Report p. 65:

> "Some utilities *seem to have* reported, as miscellaneous transmission or dispatching expenses, sizable costs that other utilities report as transmission by others expenses." [Emphasis added]

PEG Direct Report p. 65:

> "ISO members *do not seem* to have reported their ISO costs consistently since the implementation of FERC Order 668. For example, while many members have consistently reported sizable costs for ISO services in accounts like 561.8, as directed by Order 668, many have not. This *may be due* in part to varied ISO policies and the peculiarities of formula rate plans." [Emphasis added]

Two facts emerge from these citations. First, in its Direct and Commentary Reports, PEG provides no concrete evidence of widespread, systematic and significant misreporting in the FERC Form 1 accounts nor evidence citing any FERC proceedings, orders, notices or concerns about misreporting in the three accounts.[19]

Second, even if there were convincing and compelling evidence of widespread, systematic and significant misreporting in the three individual FERC Form 1 accounts, which there is not, the alleged problems PEG highlights are not problems if one includes *all three* accounts in the productivity study.

---

[19] In response to Brattle question 2.6 to provide evidence on the misreporting of costs, PEG provided a confidential spreadsheet that contained the expenses in the three excluded accounts, which it described as a "detailed analysis of the CNE costs of the sampled transmitters." The analysis seems to be simply highlighting some expenses in yellow, with no evidence or analysis that the highlighted expenses are incorrect.

The fact that some amount of expenses in account 566 (miscellaneous transmission expenses) or accounts 561.1 – 561.8 (that include some dispatching expenses) are being misreported as expenses in account 565 (transmission of electricity by others), or vice-versa, is not relevant to a TFP or cost-benchmarking study as long as all three transmission O&M accounts are included in the studies. We include accounts 561, 565, and 566 in our productivity study and the fact that there may be some amount of misreporting among the three accounts is not a major concern and does not bias the studies' results. We are less concerned about these accounts being individually precise, and more that in aggregate they are generally correct.

3. Statistical analysis of excluded O&M accounts

We performed simple statistical analysis on the excluded accounts and did not find evidence supporting PEG's decision to remove expenses in the three accounts from the study. We examined the growth and volatility in the three FERC accounts that PEG excluded and compared it to the growth and volatility in the residual accounts. Specifically, we calculated the growth and standard deviation of the expenses in the three accounts separately and the three accounts combined and compared them to the growth and standard deviation of the residual accounts. Under PEG's hypothesis, we would expect to observe significantly more volatility in the three accounts due to the alleged misreporting and inconsistent treatment.

Table 9 presents the results and shows that the volatilities of the three excluded accounts *are not materially different* from the volatilities found in some of the other residual accounts. The account with the highest volatility was not one of the three excluded accounts, it was account 563 (overhead lines) with a standard deviation of 36.5%. This was followed by one of the excluded accounts, account 566 (miscellaneous transmission expenses) with a standard deviation of 31.4%. The next two accounts with the highest volatility are not excluded accounts, they are accounts 564 (underground lines) with a standard deviation of 27.8% and account 573 (maintenance of miscellaneous transmission plant) with a standard deviation of 26.5%. Account 565 (transmission of electricity by others) one of the excluded accounts ranks fifth out of 14 accounts in terms of standard deviation at 23.7%. The third account that PEG excluded, account 561.1 – 561.8 has a standard deviation of 9.8%, the fourth *lowest* of all accounts.

In addition, we also observe that the combined growth rate of the three excluded accounts was lower than the growth rate of some of the other residual accounts, such as accounts 563 (overhead lines) and account 564 (underground lines) and very close to the growth rate of account 571 (maintenance of overhead lines).

TABLE 9: GROWTH AND VOLATILITY OF O&M ACCOUNTS EXCLUDED BY PEG AND REMAINING ACCOUNTS

Expense Account	Average Growth	Standard Deviation
Account 565: Transmission of Electricity By Others	11.26%	23.67%
Accounts 566: Miscellaneous Transmission Expenses	13.13%	31.37%
Accounts 561.1-561.8	10.02%	9.75%
Accounts 561, 565, 566 Combined	9.97%	11.49%
Account 560: Operation Supervision & Engineering	5.39%	7.7%
Account 562: Station	2.10%	6.6%
Account 563: Overhead Lines	12.76%	36.5%
Account 564: Underground Lines	10.49%	27.8%
Account 567: Rents	2.53%	14.3%
Account 568: Maintenance Supervision and Engineering	3.29%	11.9%
Account 569: Maintenance of Structures	4.82%	18.3%
Account 570: Maintenance of Station Equipment:	2.01%	4.8%
Account 571: Maintenance of Overhead Lines	9.28%	16.1%
Account 572: Maintenance of Underground Lines:	5.69%	19.9%
Account 573: Maintenance of Misc. Transmission Plant	6.03%	26.5%
All Non-Excluded Accounts	5.12%	6.95%

Sources and Notes: Brattle TFP model and S&P Global. Values are summations of all spending by utilities per account, weighting larger utilities more heavily.

4. FERC Form 1 accounting and structural change

In its Commentary Report (p. 13), PEG states "Transmission CNE reported by U.S. utilities have been affected by "structural changes" in the U.S. transmission industry." PEG does not precisely defines structural change but it is reasonable to conclude that, in the quoted sentence, PEG is referring mainly to the growth and development of *wholesale* electricity competition in the U.S. and the evolution over time of more integrated and organized regional bulk wholesale markets, especially ISOs and RTOs. The implication being that these changes are unique, significant, and, importantly, causing companies to misreport costs in these three accounts to render them unusable for a productivity study.

We disagree with the premise that any recent "structural changes" in the U.S. market render the three FERC transmission O&M accounts unusable in a transmission TFP study. Economic, technological and regulatory changes have been a feature throughout the industry's history and PEG has not provided convincing evidence to conclude that FERC's accounting system is deficient in dealing with the more recent changes. We summarized our opinion on this issue in our response to PEG question 6.2, which included:

> The term "changes in the transmission industry" is not defined, ambiguous and open to interpretation and the question calls for speculation. In general, the FERC Uniform System of Accounts (USOA) is a time-tested and well-understood regulatory accounting system that has been in place since the mid-20th century in the U.S. and has been adopted by regulators in other parts of the world. Many of the transmission O&M accounts have been in place for a long period as well, providing industry participants with a long history of cost accounting experience and institutional expertise amid the significant evolution of the industry since its inception. The regulatory accounts of the USOA identify the costs of providing transmission services and is the basis for cost of service regulation that the FERC and states utilize for transmission revenue requirements and rates. The FERC periodically issues orders to review and revise its USOA taking into account "Commission's ratemaking policies, past Commission actions, industry trends and external factors (e.g., economic, environmental, and technological changes, and mandates from other regulatory bodies.")[20]
>
> The long period of FERC accounting experience encompasses the many evolving industry structures—from one based upon vertically-integrated utilities that would interconnect and engage in limited wholesale transactions to one based upon more formal wholesale competition requirements emanating from the 1978 Public Utilities Regulatory Policies Act (PURPA), to the 1996 FERC Order 888 on transmission open access and non-discriminatory rules leading to the creation of the Open Access Transmission Tariff (OATT) and its periodic reforms, to the continued evolution of organized wholesale power markets through ISOs/RTOs.

With respect to PEG's concerns regarding *ISO Complications*, there are FERC O&M accounts that specifically capture expenses associated with regional energy markets like the ISOs and RTOs. Accounts 575 and 576 are *Regional Market Expenses* accounts. These accounts were set up to capture expenses associated with regional energy markets and the growth of ISOs and RTOs. Among some of the expenses in these accounts are (i) general supervision and direction of the regional energy markets (575.1), (ii) expenses incurred to facilitate the Day-Ahead and Real-Time markets (575.2), capacity market

[20] See, https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters.

administration (575.4), ancillary services market administration (575.5) and (iii) market monitoring and compliance (575.6).

We also note that the functions and responsibilities of ISOs are not a recent phenomenon. While some ISOs were officially formed during the period of study or they have taken on more responsibilities in the more recent years, some are older and some of the functions and objectives of these organizations have been in place for many years in other organizations such as less formal power pools. As we stated in response to PEG question 6.1 on this issue, which included:

> The term structural change is ambiguous, open to interpretation and can mean different things to different professionals as is the term “emergence of ISOs and RTOs”. We note that some ISOs/RTOs have been operation for a long period (e.g. PJM began in 1927 with three utilities, with more members following in the 1950s, 60s, and 80s) as have power pools which are the foundations of many present day ISO/RTOs.

Finally, we note that the growth and development of *wholesale* electricity competition is not just a feature of U.S. markets but similar developments have been occurring in Canada. In addition, we note that the changing U.S. wholesale power markets and its rules and regulations affects Canadian utilities that sell capacity and energy in U.S. power markets. Hydro Quebec is a major exporter of energy and capacity to the U.S. and the FERC has granted it market-based rate authority. In order to receive market-based rate authority, Hydro Quebec has to prove, in part, that it lacks vertical market power. To demonstrate a lack of affiliate vertical market power, FERC’s regulations require that:

> [A] Seller whose foreign affiliate(s) own, operate or control transmission facilities outside of the United States that can be used by competitors of the Seller to reach United States markets must demonstrate that such affiliate either has adopted and is implementing an Open Access Transmission Tariff as described in §35.28, *or otherwise offers, comparable, non-discriminatory access to such transmission facilities*.” [emphasis added][21]

HQT has an Open Access Transmission Tariff (OATT) in place that competitors can use to wheel power through its territory in much the same way as utilities in the U.S., whether operating within an ISO/RTO or in non-ISO/RTO regions. We raise these points to indicate that the wholesale electricity restructuring that has been occurring in the U.S. is of relevance and has affected HQT’s operations. Some Canadian utilities, like HQT, operate their transmission systems in ways that meet the FERC rules, regulations and requirements, including reporting requirements.

[21] 18 C.F.R. § 35.37(d).

5. FERC's use of the excluded accounts to set transmission rates

The FERC routinely uses the accounts that PEG excluded in its productivity study to set just and reasonable transmission rates. We have done a cursory search of recent FERC transmission rate cases for companies operating in the Midcontinent Independent System Operator ("MISO") territory given the relative ease of researching transmission cases in that ISO compared to other areas. Table 10 shows the results of the search—all the companies identified in the search included account 561 and account 566 in their recent formula rates. The expenses in the accounts that PEG would exclude from a productivity study—because the data are too "noisy"—the FERC includes in the setting of just and reasonable transmission rates that customers pay for the use of the transmission system.

TABLE 10: FERC USE OF EXCLUDED O&M ACCOUNTS IN FORMULA RATES: MISO COMPANIES

Utility	In Brattle Study	Filing Year Examined	Formula Rate Includes Account 561	Formula Rate Includes Account 566
Ameren Illinois Company	No	2020	Yes	Yes
City Utilities of Springfield	No	2021	Yes	Yes
Duke Energy Ohio, Inc. & Duke Energy Kentucky, Inc.	No	2020	Yes	Yes
Entergy Arkansas, LLC	Yes	2021	Yes	Yes
Indianapolis Power & Light Company	Yes	2021	Yes	Yes
MDU Resources Group Inc.	Yes	2020	Yes	Yes
Mid-Atlantic Interstate Transmission	No	2019	Yes	Yes
Northern Indiana Public Service Company	Yes	2021	Yes	Yes
Public Service Electric and Gas Company	Yes	2021	Yes	Yes
Southern California Edison Company	Yes	2021	Yes	Yes
Virginia Electric and Power Company	No	2020	Yes	Yes

Note: Mix of companies determined by data availability. Data is sourced from company individual webpages and from MISO's list of general FERC filings.

With respect to account 565 (transmission of electricity by others), the FERC provides guidance on this account for recovery in transmission rates for tariffed customers so as to determine what amount of the expenses to recover from tariffed *vs.* non-tariffed customers. As we stated in response to PEG-IR-6.4:

> Account 565 is listed under FERC Transmission O&M accounts. The FERC and transmission companies utilize account 565 as an O&M expense in the transmission companies' Annual Transmission Revenue Requirement ("ATTR").[22] FERC's definition of the account is: "This account shall include amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others." [emphasis added]. The FERC has provided guidance to the industry on this account and what should be included in it and has stated that recovery of payments for transmission by others is allowed "only when the

[22] *See*, Nebraska Public Power District v. Tri-State Generation and Transmission Association, Inc., Southwest Power Pool, Inc., Docket No. EL 18-194-000, issued December 20, 2018.

> facilities are used either on a day-to-day basis to transmit power and energy for tariff customers, or when they form part of the pertinent company's integrated transmission system."[23] [emphasis added]. Thus, expenses included in account 565 represent legitimate transmission expenses incurred to provide service for tariff customers. These are relevant transmission O&M expenses to include in a transmission TFP and cost-benchmarking study.

6. Additional observations

- **PEG includes accounts 561.1-561.8 and 566 in its cost-benchmarking study**

Unlike the productivity study, in the econometric cost-benchmarking study PEG included account 561 and account 566 but keeps transmission of electricity by others out. In its Direct Report (p. 90), PEG states:

> "We did *not* exclude dispatching expenses or miscellaneous transmission expenses because HQT did not consistently itemize these expenses. However, we did remove some companies from the sample which reported uncommonly large dispatching or miscellaneous transmission expenses which we suspect other companies would have reported as transmission by other expenses. All of the anomalies occurred during years when these companies were ISO members. This is the main reason for differences in the econometric and productivity samples."

This statement reveals two salient points. First, PEG removes transmission O&M expenses in its productivity study that HQT in fact incurs. This confirms the fact that PEG is removing legitimate transmission O&M expenses from its productivity study, thus biasing its measured TFP and PFP O&M growth.

Second, PEG seems to concede that whatever problems it believes exist with accounts 561.1 – 561.8 and account 566, the problem does not affect all companies. Thus, a reasonable alternative that PEG could have done instead of excluding these legitimate transmission O&M expenses from its productivity study would have been to do the same as in the benchmarking study and remove some companies from its sample to determine whether excluding the expenses from all companies was reasonable. We asked PEG which companies it removed from it benchmarking study and the companies were Commonwealth Edison, Kansas Gas & Electric, Oklahoma Gas & Electric, PECO Energy, San Diego Gas & Electric, and

[23] *See*, *N.Y. State Elec & Gas Corp*, Opinion No. 447, 92 FERC ¶ 61,169, at 61,584 (2000), *order on reh'g*, Opinion No. 447-A, 100 FERC ¶ 61,021, *reh'g denied*, Opinion No. 447-B, 101 FERC ¶ 61,037 (2002), *order on reh'g*, Opinion No. 447-C, 103 FERC ¶ 61,321, at P 8 (2003) (emphasis added))

Southern California Edison. As a sensitivity, we re-ran our TFP model removing these companies and we present the results in Table 11 below. We asked PEG to re-run its TFP model but under the same cost information used for its benchmarking, it found TFP growth of -1.01% and PFP O&M growth of -2.22%.[24]

TABLE 11: TFP RESULTS REMOVING SIX COMPANIES PEG REMOVED IN ITS BENCHMARKING STUDY

Model	TFP Growth (1995 - 2019)	Growth of PFP O&M (1995 - 2019)
Brattle Base Model	-1.04%	-3.38%
Brattle Base Model with Six Companies Removed	-0.88%	-3.10%

Note: The six companies removed by PEG were Commonwealth Edison, Kansas Gas & Electric, Oklahoma Gas & Electric, PECO Energy, San Diego Gas & Electric, and Southern California Edison.

– **Rationale for excluded "transmission of electricity by others"**

Throughout its Commentary Report, PEG refers to a recent transmission TFP and cost-benchmarking work of Mr. Fenrick in several recent cases in Ontario before the Ontario Energy Board.[25] In one of the cites, PEG references Mr. Fenrick's decision to exclude account 565 (transmission of electricity by others) from his TFP study on behalf of Hydro One.[26] Specifically, PEG states (p. 13-14):

> "Mr. Fenrick threw out transmission by others expenses in his latest productivity and benchmarking studies for Hydro One, stating that 'Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not removed, would yield an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values.'"

We disagree with this rationale for excluding transmission of electricity by others.[27] We believe that the point above misses the classic economic "make or buy" decision-making that all firms encounter in their production of goods and services. Transmission of electricity by others includes a utility purchasing transmission services from other entities in order to bring in power and energy into its service territory

[24] PEG response to Brattle question 7.3.

[25] A search of "Mr. Fenrick" in PEG's Commentary Report revealed close to 40 references throughout the report on numerous topics.

[26] Mr. Fenrick's transmission TFP study included two out of three accounts that PEG excluded, accounts 561.1-561.8 and 566.

[27] As discussed above, the FERC permits expenses in this account to be included in formula rates, "only when the facilities are used either on a day-to-day basis to transmit power and energy for tariff customers, or when they form part of the pertinent company's integrated transmission system."

to meet the needs of its tariffed customers and its native load. In some cases, the utility uses its own transmission facilities to provide itself with transmission services, while in other instances it is purchasing transmission services from the market and often uses a combination of the two. In one case, the costs show up through the capital and associated O&M accounts, in the other case it shows up as an annual expense in account 565. Both serve a similar function—to provide transmission services and deliver power and energy to customers. Some companies in our sample have large expenses in this category while other have low expenses, reflecting the individual tradeoffs and network characteristics unique to each company.[28] We disagree with what seems to be the implication of the above quote: if a company buys an input, rather than self-supplying, it should not count in a TFP study.[29]

- **Assumption that a company can lose 50% of its costs and produce same level of output**

Removing such a large amount of O&M expenses implicitly assumes that outputs would be unaffected. PEG does not discuss whether the removal of legitimate transmission O&M expenses would necessitate adjusting transmission output in a TFP study, nor whether other inputs would need to be adjusted to maintain the same level of output.[30]

- **Accounts 561.1-561.8**

PEG refers to Load Dispatching as accounts 561.1-561.8. In fact, only half of the subaccounts (561.1 - 561.4) include dispatch in the title of the subaccounts. The other subaccounts do not. Thus, any alleged misreporting associated with this account would apply to only a subset of the account. The other subaccounts are (i) 561.5: Reliability planning and standards development, (ii) 561.6: Transmission service studies, (iii) 561.7: Generation interconnection studies, and (iv) 561.8: Reliability planning and standards development services.

- **Accounts 569.1 – 569.4**

In PEG's Commentary Report (p. 64), PEG highlighted similar concerns with data misreporting problems with accounts 569.1-569.4. Specifically, PEG stated:

> "Accounts 569.1-569.4 were established, under transmission load dispatching, for maintenance of these same assets. These accounts were intended chiefly for

[28] In a transmission TFP study that excludes transmission of electricity by others, a company that has a high and rapidly growing share of expenses in this category would artificially have higher TFP growth than other firms that have a low and slow growing share of these expenses and rely more on their own transmission network to provide power and energy to its customers.

[29] Excluding transmission of electricity by others in a transmission TFP study, would be akin to excluding purchase power expenses from a generation TFP study on the grounds that purchase power expenses are not commensurate with output values.

[30] When transmission O&M input quantity is measured as expenses divided by a price index—as is the case in PEG' studies—excluding certain O&M expenses necessarily reduces the quantity *level*.

> use by ISOs but some utilities may have elected to start reporting costs in these same accounts."

Nevertheless, PEG did not exclude these accounts in its productivity study or its cost-benchmarking study, in spite of the fact that PEG's concerns with these accounts are identical to the concerns in the other accounts.

- **Accounts 575 and 576**

PEG indicates in its Direct Report (p. 69) that it excluded accounts 575 and 576 from both its productivity and benchmarking studies. Accounts 575 and 576 are *not* transmission expenses under the FERC's Uniform System of Accounts. The FERC labels them as *Regional Market Expenses*. There is no reason to consider them as part of a transmission productivity study.

C. Capital

1. Benchmark capital

PEG's comments on Brattle's Direct Report took issue with the denominator Brattle used to calculate stock used with One Hoss Shay. Brattle uses a weighted average of an historical new construction price index, with more weight given to recent years. PEG recommends a simple average. We disagree.

As noted by PEG in the quote above, "…*the estimate of the capital quantity in the benchmark year is inexact*…". We generally concur with this point and stated in response to PEG question 5.1, "[s]ince we do not have data on the additions to plant prior to the benchmark year, the denominator serves to approximate the unavailable historical data." PEG provides a mathematical example in an Appendix in its Commentary Report but does not explain *conceptually* why the simple average is preferred. The example's statement of how to calculate an arithmetic average—"[t]he capital quantity can be calculated by dividing gross plant value by an arithmetic average of the three capital prices *since* gross plant value/average asset price = 6/[(P1+P2+P3)/3] = 6/[(1+2+3)/3] = 3"—does not *explain* why a weighted average would be incorrect in this case. PEG's example, and its support for the simple average, depends on its assumption about the *timing* of historical investments leading up to the benchmark year—it assumes constant investment over the three years, a strong assumption in the transmission industry where investment is lumpy. It also assumes that technology remains constant during the period, so that a *new* unit of capital today produces the same capital services as a *new* unit of capital 46 years prior, another strong assumption, especially over the 46-year life span of transmission plant and equipment.

2. Leveling capital input prices

PEG's Commentary Report (pp. 24) states that Brattle did not levelize capital asset price indexes because "All US utilities were assumed to pay the same rates for construction in 2001". PEG appears to refer to Brattle's use of the Handy-Whitman Index for the purpose of capital price calculations. The Handy-Whitman index, like other widely available cost indexes, provides the ratio of cost of electric utility construction in a given year to that in a base year. While the value of the index is different for every region in a given year, the native Handy-Whitman index uses 1973 as the base year with a value of 100 and Brattle re-bases this to 2001. The choice of the base year is arbitrary and has no effect on the results of a total factor of productivity study. As an example, Brattle could choose to re-base the Handy-Whitman index to the year 1926. In this case, the apparent rates for construction in the year 2001 would differ on a regional basis due to the rebasing, but the overall TFP and benchmarking results would be unchanged. Therefore, the base year does not imply that entities pay the same prices; it merely indicates a common starting point for a cost index that tracks the trajectory of prices in a given region. Based on the workpapers provided in their filing, PEG's own calculation of the labor price index, which uses the regional employment cost index for private industry workers based on four regions – (Northeast, South, Midwest, West) – uses the year 1988 as the base year in which the labor price index for all four regions is set to 100. In both these examples, the common index value in the base year does not imply that the absolute levels of prices across regions are identical. It only indicates a common starting point to base index values for subsequent years on.

3. Additional observations

- **Use of the same rate of return for each company in a given year**

PEG uses the same rate of return for each company in a given year. Rate of return is a key component of the capital price. PEG's assumption prevents the level of a company's rate of return to vary among companies in each year of the sample period. This minimizes the variation in the overall capital price among companies. This assumption is not required as the data are available and Brattle uses a company-specific rate of return so that each of the 74 companies have a different rate of return.

- **No provision for taxes or accelerated depreciation**

PEG does not take into account taxes or the effects of accelerated depreciation on the capital price. While ignoring taxes effectively lowers the price of capital and ignoring the tax benefits of accelerated depreciation effectively increases the price of capital, there is no reason to believe the net effect is zero.

- **Useful life**

PEG used a 47-year life for transmission in this study (Direct Report p. 98), while in its 2019 study before the Ontario Energy Board PEG uses 46-year life.[31] PEG provides no explanation given for the change in asset lives.

D. Labor price

PEG states (Rebuttal Report pp. 24) that "However, our understanding of their working papers is that state-by-state wage data were not actually used in Brattle's calculations." Brattle uses state specific wage data for each company in the productivity sample to calculate a mean wage level for 2019 as a base year[32]. In order to impute the wage data for every other year in the sample, we use the Employment Cost Index for Wages and Salaries for Private industry workers in Utilities, as published by the US BLS. However, this employment cost index for utility industry workers is only available at the national level with no data available at a more granular regional level. Since the labor price index used in the productivity study tracks the growth of wages for companies in the sample, the resultant labor price index turns out to be the same for all companies in the sample as it is derived from the national employment cost index for utility workers. It must be noted that labor accounts for only approximately 5% of the total costs in the Brattle productivity sample. As a sensitivity, Brattle used the same regionalized cost indexes as described by PEG in their Direct Report and found virtually no impact on our TFP or cost benchmarking conclusions.

E. Common costs

Our sensitivity analysis in our Direct Report showed that our *TFP growth* results are materially affected by our choice of excluding common costs—administrative and general ("A&G") and general plant. However, our PFP O&M results changed little with inclusion of common costs and the inclusion or exclusion of common costs does not affect our econometric cost-benchmarking conclusions. Unlike transmission O&M expenses excluded in PEG's study, common costs are by definition, not transmission related and cannot be directly assigned as such. TFP studies, as ours, can be sensitive to the methodology used to include common costs and thereby lessening the validity of the studies.

---

[31] See Mark Newton Lowry, Ph.D., "Empirical Research for Incentive Regulation of Transmission," February 4, 2019, p. 33.

[32] State specific wage levels for 2019 are obtained from the Occupational Employment and Wage Statistics (OEWS) published by the U.S. BLS.

F. Output

Regarding Brattle's use of output variables, specifically the peak demand variable, PEG notes two points of contention with our work. The first pertains to Brattle's use of the monthly peak demand variable in the benchmarking study. PEG alleges that the use of the monthly peak definition tends to favor HQT in the benchmarking study. We address this critique in Section III.A.6. The second involves Brattle's use of ratcheted peak demand in the benchmarking study but not the productivity study. We provided our rationale in response to PEG-IR-3.1:

> "The output measures for a productivity study can be deflated revenues or physical units of output in a given year. Ratcheted peak demand does not correspond with the actual peak demand observed in a given year and thus is not consistent with the physical unit of output observed and produced in a given year, given the input services—i.e., capital, labor and MR&S services—in that year. In addition, using ratcheted peak demand constrains the output growth to be no lower than zero in any given year, even though physical peak demand units produced in a given year can show negative growth. Not permitting a physical output unit to show negative growth biases upward the output growth rate."

In addition, we note that concerns about an output variable never being able to decrease were raised in recent Ontario TFP proceedings. We understand that these concerns were part of the reason that Mr. Fenrick now uses a 10-year rolling average of annual peak demand for its productivity study, rather than ratcheted peak demand that he uses only for the cost-benchmarking work.

III. Econometric Cost Comparison: Concerns with PEG's Study and Responses

A. Econometric model

1. PEG's econometric cost benchmarking fails to control for HQT's unique factors

A challenge in econometric cost benchmarking is to control for as many cost drivers as possible in the econometric model to ensure that a firm is not unfairly rewarded or penalized when the model is used to make predictions about costs and to reach conclusions about relative firm efficiencies. For example, if the percent of transmission lines that are underground were not an explanatory variable, the econometric model would penalize a company with a large share of underground lines because having more underground lines is more costly and the costs produced by the model would unfairly be both unreliable and to the detriment of the firm. If not included in the model, the effect of the percent of transmission lines that are underground would show up in the error term (the residuals) of the model. For a firm with a large share of underground lines the residuals would, all else equal, be large. Consequently, the model's predicted costs would be lower than actual costs leading to an incorrect conclusion about the firm's relative performance.

As stated by PEG in its Direct Report (p. 28):

> "We noted above that simply comparing the results of a 100-meter sprinter racing uphill to a runner racing on a level course is not ideal for measuring the relative performance of the athletes. Statistics can sharpen our understanding of each runner's performance. For example, a mathematical model could be developed in which time in the 100-meter dash is a function of track conditions like wind speed, racing surface, and gradient. The parameters corresponding to each track condition would quantify their impact on times. The samples of times turned in by runners, under the varying track conditions, could be used to estimate model parameters. The resultant run time model could then be used to predict the typical performance of the runners *given the track conditions they faced*." [Emphasis added]

PEG's econometric models have a fundamental methodological flaw because they fail to control for those *unobservable* economic and business condition factors that are specific to each firm, and especially HQT, which has unique cost characteristics. By not controlling for HQT's unobservable factors, PEG's predictions significantly under estimate HQT's costs that are outside management's control. These factors include characteristics such as the type of organization (*e.g.*, HQT being a government-owned crown corporation), unique technology, and challenging logistical conditions to name a few, see more below. PEG did not have independent variables that controlled for these and other factors described below. When PEG uses its econometric model to predict and to benchmark HQT's costs it assumes that if the economic and business factors that cannot be included in the econometric model increase costs more for HQT than for US companies, then HQT is relatively less efficient.[33] This assumption, which is wrong and makes PEG's cost benchmarking unreliable, is the main explanation for the differences between Brattle and PEG's cost-benchmarking results.[34]

---

[33] The simple OLS model assumes the error terms are uncorrelated with the included variables and that they have an average of zero. Therefore, in order for PEG's assumption to be valid, the effect of the left-out variables for *all* companies over sufficiently long time period would be close to the OLS constant. Accordingly, when PEG uses its econometric model to predict and to benchmark HQT's costs it assumes that HQT and all U.S. companies *are nearly identical* when it comes to all the economic and business factors that cannot be included in the econometric model.

[34] We show below using PEG's data that statistical tests reveal that it is a mistake to ignore the firm-specific unobservable effects in the econometric model and once corrected and using PEG's data—with all its

The effects of ignoring the firm-specific unobservable effects are twofold. First, PEG's parameter estimates are biased and inconsistent, resulting in incorrect cost predictions. Second, PEG's models ignore the unique, unobservable HQT factors when predicting HQT's costs. This makes PEG's cost-benchmarking results unreliable, as HQT is very different in the conditions that it faces that are outside management's control compared to the U.S. firms.

PEG's Direct Report spent approximately five pages (pp. 83-89) discussing how unique HQT was in comparison with its U.S. counterparts. Among the unique HQT characteristics that PEG identified were:

- Being a crown corporation (p. 83) and having a unique corporate structure (p. 87);
- Transmission of large amounts of power over large distances has over the years encouraged HQT to use *unusual and innovative technologies* including 735 kV alternating current lines and high-voltage direct current line, new tower design, and remote monitoring systems (p. 85);
- Sizable lakes, rivers, cold winters throughout territory with postes sometimes housed in structures (p. 86);
- Special logistical challenges, many facilities are distant from good roads (p. 86);
- Extensive telecommunications network (p.85);
- HQT operating asynchronously from North America's Eastern Interconnection (p. 85);
- Sizable portion of HQT's access to transmission corridors achieved by easements (p. 85);
- Hard rock close to the surface, difficult to establish footing for structures (p. 86);
- Accounting idiosyncrasies (p. 88);
- A list of cost advantages including scale and scope economies, low borrowing rates, and no income taxes (pp. 86-87);

In its econometric cost-benchmarking model, analysis and its predictions for HQT, PEG does not control for the above-listed factors. In response to Brattle question 5.1, PEG conceded that although it believes it has a good model, it did not capture all relevant factors that affect total, CNE and capital transmission costs.

Since these factors are not included among the independent variables and they tend to make HQT relatively more costly, their effects on costs show up as large residuals for HQT and incorrectly lead to a conclusion that HQT is a very poor performer. PEG confirmed this last point on the residuals. We asked PEG in question 5.2, if any relevant factors are not included in the model but that likely have an impact

assumptions regarding capital, labor, MRS, output, and common costs—PEG's cost-benchmarking conclusions are similar to Brattle's cost-benchmarking conclusions.

on transmission costs—because, for example, they may be hard to capture in a variable—how does PEG's model account for these factors? PEG's response was:

> "These factors would appear in the difference between predicted and actual cost and would affect HQT's benchmarking score."

Using PEG's example above, failing to control for HQT's unique conditions would be like "comparing the results of a 100-meter sprinter racing uphill to a runner racing on a level course." While it would be a challenge to obtain data and create independent variables for many of the listed factors, the use of the correct econometric model mitigates the consequences of not including such variables. PEG's use of OLS does not.

PEG's failure to include HQT when estimating its econometric model compounds the problems by making the parameters of the independent variables less reliable. Were HQT similar to its U.S. counterparts in terms of the independent variables, this exclusion may not have been very problematic. That is not the case, however, as HQT is an outlier with respect to some of the independent variables. In response to Régie 11.1, we indicated that in terms of peak demand, for 2019 Florida Power & Light was the company in our sample with the largest peak demand at 24,241. In 2019, HQT's peak demand was 40,806—approaching almost double the amount. In terms of transmission line length, for 2019 Pacific Gas and Electric (PG&E) was the company in our sample with the largest transmission length at 36,659, compared to 34,530 for HQT. However, PG&E was not in PEG's sample. While line mileage for PG&E was comparable to HQT, the next two largest companies in the US sample, PacifiCorp and Southern California Edison, had a total transmission line mileage of 17,616 and 14,526, respectively – only about half as much as HQT.

As a result, PEG's parameters for these two variables—as well as their squared and interaction terms—are not reflecting this unique aspect of HQT. In other words, PEG's slope coefficients would be different had it included HQT in its regression models. This reduces the benefits of explicitly controlling for these two factors in its model. Because the purpose of including these independent variables in a cost-benchmarking study is to control for those factors that make the sample companies more or less efficient, excluding HQT makes the effects produced by its model less reliable.

Returning to the sprinter example, it would be akin to estimating a model where the gradient of the tracks ranged between 2 and 5 degrees, and using that model to predict the time of a runner on a track with a 10-degree gradient. We would not expect such a model to be able to predict accurately the runner's time.

2. Brattle's econometric cost benchmarking controls for HQT's unique factors

Brattle utilizes a fixed-effects, FE, model for our econometric cost-benchmarking analysis and for predicting HQT's costs. A FE estimator is very well suited to the econometric problem at hand because it controls for HQT's unique factors when benchmarking HQT's costs. Specifically, the FE model treats all of the companies' unique characteristics as another parameter to estimate and used in making predictions. In essence, each company's fixed effect parameter is another independent variable and ensures that the model does not penalize or reward a company for its unique characteristics when making prediction. In other words, it ensures that the 100-meter sprinter racing uphill and the runner racing on a level course are compared properly.

In the case of HQT, using FE ensures that HQT is not penalized for the list of unique factors that PEG identified in its Direct Report, such as "unusual technologies", being a crown corporation, and special logistical challenges to name a few. The FE model explicitly accounts for those factors when estimating parameters and when used to make predictions. The fixed effects parameters are no different than and serve the same purpose as any of the other independent variables in the same way that the independent variable percentage of transmission lines underground ensures that the model does not unfairly penalize a firm for its percent of buried lines.

As we stated in response to PEG 12.1:

> "We use the fixed-effects model for cost-benchmarking HQT vis-à-vis the U.S. sample of transmission companies. The fixed effects model estimates a unique constant term for each firm in our sample, including HQT and utilizes it for prediction. It is common to refer to this unique constant term as the unobserved heterogeneity of each firm in our sample, including HQT. The unobserved heterogeneity represents all those unobserved, time-invariant factors that affect transmission costs and that differ across firms and is a crucial part of cost-benchmarking. The fixed effects model controls for the unobserved heterogeneity and uses each firm's constant term for the cost-benchmarking."

In response to PEG 13.1, we stated:

> "We estimate our benchmark models utilizing a panel data set. Our data set has observations for the same 74 transmission companies over the period 1994-2019. This is a rich data set that can be exploited in ways that would not be possible had we not had data on the same companies over time but instead had data on different transmission utilities over time, the latter type of data set being known as pooled cross-sectional data. Fixed effects and random effects estimators are panel data estimators and it is best practice in econometrics and

not in any way controversial to utilize panel data estimators with panel data. A fundamental strength of panel data estimators is its ability to obtain consistent estimators in the presence of omitted variables. Omitted variable bias is a common challenge in econometric modelling because no matter how well specified a model is, it is unlikely that all observable variables have been included. More important, there are factors that are not possible to include in an econometric regression because the variable is unobservable to the researcher—i.e., it may not be feasible to measure—or due to the resources that would be required to accurately and objectively measure the variable, e.g., intangible factors such as quality of management and workers. These are all factors that vary among our sample of 74 utilities and that likely have direct impacts on transmission costs. Not using a panel data estimator for the panel data at hand and instead utilizing pooled OLS is a mistake, as it is not using the proper tool for the job at hand, as reflected in the result of the Hausman test discussed in response to 13.11 below. The RE estimator is preferred to pooled OLS when the researcher fails to reject the null hypothesis of no correlation between the unobserved effects and the regressors."

Finally, in response to PEG 13.2, we stated:

"The FE is ideal for benchmarking HQT to the U.S. sample of transmission companies. As discussed in response to 12.1, the fixed effects model estimates a unique constant term for each firm in our sample, including HQT. These constant terms are used for prediction. The unique constant term is, by definition, the unobserved heterogeneity that represents all those unobserved, time-invariant factors that affect transmission costs and that differ across firms and is a crucial part of cost-benchmarking. Ignoring this heterogeneity in a benchmarking exercise is a mistake and biases the results, as demonstrated through the Hausman test result in our sample."

In responses to data requests from Brattle and intervenors, PEG suggests that the correct way to implement the FE for cost benchmarking in this case is to *ignore* HQT's unique factors when using the model to predict HQT's costs. This approach assumes that HQT's unique factors are *endogenous* and under the control of management. Under this approach, PEG's cost benchmarking results suggests that with different management HQT could lower its costs by *more than 50 percent* just to be an average cost performer. We do not believe this is a credible result and is evidence of the flaw in PEG's cost-benchmarking analysis. PEG does not discuss the basis of such large cost inefficiencies on the part of HQT nor how different management would be able to change so dramatically the cost impact of HQT's unique features. Nor does it discuss the role of regulation, and why it has permitted such large inefficiencies throughout the years.

PEG's approach would automatically treat any time-invariant variable as an inefficiency, regardless of what it was. Including the unique constant terms is the strength of the fixed effects approach. That is, leaving out fixed effects not only biases the coefficients of included variables, but it also (as PEG's description indicates) makes the unsupported assumption that all time invariable variables are pure inefficiencies and thus penalizes HQT's unique conditions. PEG is fine with holding companies harmless with respect to all included variables—as it should—but seems to want to put companies on the hook for variables that are hard to measure.

3. Academic literature supports the use of panel data models in econometric cost-benchmarking

In its Commentary Report (pp. 20-23) PEG posits that panel data estimators, such as fixed effects, are not good for determining inefficiencies among firms in econometric benchmarking studies[35] and suggests that they are not used in published econometric benchmarking studies.[36] In this section, we provide a review of the academic literature on panel data models and econometric benchmarking of firm inefficiencies. In a subsequent section, we respond to PEG's critiques on the use of fixed effects for econometric cost benchmarking.

In the Appendix, we provide a table with a list of some academic articles on the use of panel data models in econometric benchmarking and measuring firm inefficiencies. While the academic literature on the topic is voluminous and we have not performed an exhaustive search, from our review panel data models are common in such empirical research, including their use in the electricity sector. The use of panel data estimators has a long history, dating back more than forty years beginning with the study by Pitt and Lee (1981) that examined technical inefficiencies in Indonesian textiles with the use of a random effects model. Another early study was Schmidt and Sickles (1984) who used several estimators for estimating firm inefficiency in the airline sector, including the fixed effects model and the random effects model. The authors specifically recommend against using OLS, as the random effects model is preferred when individual fixed effects are not important.

Kumbhakar (1991) provides a theoretical discussion on the use of panel data models and develops methods to measure technical inefficiency using both random and fixed effects treatment of firm and time effects. Kumbhakar follows this with Kumbhakar and Heshmati (1995) who apply random effects model to measure efficiency in Swedish Diary Farms. The authors cite the use of fixed effects as an appropriate choice, but select the random effects because they are dealing with a "rotating" panel as farms enter and leave their sample throughout the period. Horrace and Schmidt (1996) use panel data

[35] See for example, PEG Commentary Report (p. 23): "The 'unique constant term' for HQT reflects the Company's average inefficiency as well as the cost impact of excluded time-invariant cost drivers. This corrupts Brattle's predictions as benchmarks of cost efficiency." We respond directly to this observation further below.

[36] See PEG Commentary Report (p. 20).

and maximum likelihood, random effects (GLS) and fixed effects estimators to estimate firm inefficiency in a number of sectors, including a panel data of Texas electric utilities.

Farsi and Filipino (2004) use a panel data of 59 electric distribution utilities in Switzerland over a period of 9 years and obtain efficiency rankings using random effects and fixed effects models. Commenting on the use of panel data and models, they state (p. 2):

> "There is a common perception that the estimation results can be improved using panel data. In contrast with cross-sectional data, panels provide information on same companies over several periods. Moreover, panel data models can better control for unobserved heterogeneity among companies. This perception is supported by suggestive evidence."

Farsi, Filipino and Greene (2005) use panel data to estimate cost functions for Swiss railways companies. The authors utilize several estimators including fixed effects and random effects. Importantly, the authors utilize the Hausman test to confirm correlation between firm-specific effects and the explanatory variables and inform the choice of appropriate estimator. Commenting on the use of panel data, the authors state (p. 71):

> "Railway networks are characterized by a high level of output heterogeneity. Networks with different shapes and densities have different organization and coordination problems, thus different costs. Furthermore, environmental characteristics such as topography and climate can influence the operating costs. In many cases, the information is not available for all output and environmental characteristics. Many of these characteristics are therefore omitted from the cost function specifications. Moreover, there exist other omitted variables such as differences across companies in accounting procedures that are generally not taken into account. *Unobserved firm-specific heterogeneity can be taken into account with conventional fixed or random effects in a panel data model.*" [Emphasis added]

Farsi, Filipino and Greene (2006) continue their work on the use of panel data models for measuring firm inefficiency by examining 59 electricity distribution utilities in Switzerland. The authors state (p. 273):

> "As opposed to cross-sectional data, panels provide information on same companies over several periods. Repeated observations of the same company over time allows an estimation of unobserved-specific factors, which might affect costs *but are not under the firm's control*. Individual companies operate in different regions with various environmental and network characteristics that are only partially observed. *It is crucial for the regulator to distinguish between inefficiency and such exogenous heterogeneity*." [Emphasis added]

Hausman and Ros (2013) use a panel data to benchmark telecommunications prices among developing economies.[37] The authors used fixed effects estimation to estimate price equations and used the price equations to benchmark Mexican mobile and fixed telecommunications prices. This approach is the general approach that Brattle and PEG use in this proceeding—estimate econometric models as best as possible, use the models to make predictions on costs and compare the actual costs to predicted costs to reach conclusions about firm inefficiency.

4. Statistical tests applied to PEG's data show use of OLS is incorrect

In our Direct Report (p. 61), we conducted a statistical test—the Hausman test—and concluded that it would be a mistake to ignore and not control for HQT's unique features when estimating our econometric model and comparing HQT's predicted costs to its actual costs.[38] In this section, we conduct the same test on PEG's data as well as conducting additional statistical tests and show that it was incorrect for PEG to ignore and not control for HQT's unique features when conducting its econometric cost-benchmarking analysis.

PEG's econometric methodology ignores and fails to control for each transmission companies' unique, unobservable feature. In the case of HQT, PEG's model fails to control for the unique HQT features discussed above—*e.g.*, being a crown corporation, having unusual and innovative technologies, and special logistical challenges. Specifically, PEG's econometric methodology fails to control for these unobservable factors because the pooled OLS model includes all those unobservable effects in the error term of the regression. If the unobservable effects are important in determining costs and there is significant unobserved heterogeneity among the firms, then use of pooled OLS will be unreliable for cost-benchmarking purposes. Using OLS not only will distort the residuals (error terms) that are the measure of relative efficiency, but also provide biased and inconsistent parameters. In other words, it would not be able to distinguish between a sprinter running uphill and one running on a flat track. By contrast, the fixed effects model removes those effects from the error term and treats them as independent parameters to estimate, thus explicitly controlling for those important factors when comparing predicted with actual costs. The random effects model is a middle ground between pooled OLS and fixed effects by partially leaving in the unobserved heterogeneity in the error term.

We can use the Hausman test to determine if PEG's assumption of ignoring HQT's unique characteristics—*i.e.*, the assumption of leaving each company's unobserved heterogeneity entirely in

[37] Hausman is Professor Jerry A. Hausman and the inventor of the Hausman test, Ros is Agustin J. Ros and co-author of this report.

[38] *See*, Jerry A. Hausman, *Specification Tests in Econometrics*, 46 ECONOMETRICA 1251, 1262-63, 1273 (1978).

the error term—was correct.[39] In Table 12, we provide the results of the Hausman test using the Brattle and PEG benchmarking panel datasets for total cost-benchmarking. In both instances, the p-value obtained from the Hausman test is small enough to reject the null hypothesis, which means that PEG's econometric parameters are biased and inconsistent and are unreliable for cost-benchmarking purposes.[40] An additional overidentification restrictions test accounting for heteroscedasticity also rejects the null hypothesis and confirms the results of the Hausman test.[41]

We also conducted an additional test that involves the use of dummy variables for each group or company in the model specification.[42] In particular, the dummy variables, which have a value of 1 if an observation belongs to the given company and 0 otherwise are included in a simple OLS model. The advantage of using this approach is that a researcher can directly test, in a "test for joint significance", whether or not the use of dummy variables, the company fixed effects, are important. The null hypothesis under this test states that the coefficient estimates for the dummy variables are all *jointly* zero. As a matter of implementation, we take PEG's OLS specification for total costs as given and introduce company specific dummy variables to perform this test. In Table 12, p-values obtained from this F-test for joint significance on both, the Brattle and PEG benchmarking datasets, are very low meaning that the null hypothesis can be safely rejected. The result of this test points directly to the presence of omitted variable bias in the simple OLS model that PEG estimated.

TABLE 12: STATISTICAL TESTS ON PEG'S DATA: HAUSMAN, OVERIDENTIFICATION AND F-TESTS[43]

	Brattle Benchmarking			PEG Benchmarking		
	Hausman Test	Test accounting for heteroskedasticity	F-test for Joint Significance	Hausman Test	Test accounting for heteroskedasticity	F-test for Joint Significance
p-value	0.0005	0.0056	0.0000	0.0000	0.0000	0.0000

Note: The tests conducted on PEG's total cost dataset utilize the data and regression specifications provided by

[39] Specifically, in lay terms and for our purposes the null hypothesis of the Hausman test is that there is no correlation between the unique, company-specific factors and the independent variables. A rejection of the null hypothesis means that the unique, company-specific factors are important and failure to control for them would result in biased and inconsistent parameter estimates. Importantly for our purposes, failure to reject the null hypothesis means that PEG's pooled OLS methodology is econometrically in error and leads to biased and inconsistent parameter estimates and unreliable cost-benchmarking conclusions.

[40] In econometrics, a p-value smaller than 0.05 is said to be a statistically significant result and is considered an acceptable level to be able to reject the null hypothesis.

[41] Specifically, we conducted a variant of the Hausman test—an overidentification restrictions tests—which tests for whether the regressors are uncorrelated with the company-specific factors under the presence of heteroskedastic errors, using the xtoverid command in Stata. The p-value for this test, provided in Table 12, also results in a rejection of the null hypothesis and confirming PEG's pooled OLS results in biased and inconsistent parameter estimates and unreliable cost-benchmarking conclusions.

[42] Page 20 of PEG's Commentary on Brattle's Empirical Study provides an alternative way to implement fixed effects estimation.

[43] The results from Table 12 hold for both, capital costs and O&M costs – the results of the Hausman and F-tests are all statistically significant implying that the consideration of a fixed effects model is warranted.

PEG in their workpapers. The tests conducted on the Brattle dataset utilize the regression specifications provided in the February Direct Report. Test accounting for heteroscedasticity was the overidentification test using xtoverid. The F-test for joint significance is a test whether the individual company dummy variables are statistically significant.

In summary, the three tests described in this section support the use of the fixed effects approach for the benchmarking exercise. Using PEG's own data and based upon the result of the three statistical tests, PEG's econometric models yield unreliable results for benchmarking HQT's costs.

To be clear, when conducting our statistical tests on PEG's dataset we used all of PEG's methodology and approach in its TFP and cost-benchmarking work. This includes PEG's exclusion of the sizable amount of transmission O&M costs, PEG's approach to capital, labor, common costs, output and PEG's sample of companies. In the next section, we demonstrate that using PEG's data and applying the correct econometric model results in very different cost-benchmarking conclusions.

Finally, we compare HQT's fixed effects with the fixed effects of each of the 74 companies in our sample. Recall, the fixed effects represent all the unobservable, unique factors that make providing transmission services more or less costly, while holding all other factors constant. For HQT it includes those factors like being a Crown Corporation, unique technologies and challenging logistical conditions.

Figure 1 presents a summary of the fixed effects obtained from Brattle's preferred benchmarking regression for total costs in order of the size of fixed effects. The fixed effects have been translated to real total cost measures for the sake of comparison.[44] As can be seen in the figure, the cost impact of HQT's unobservable, unique factors are the highest all the other companies.

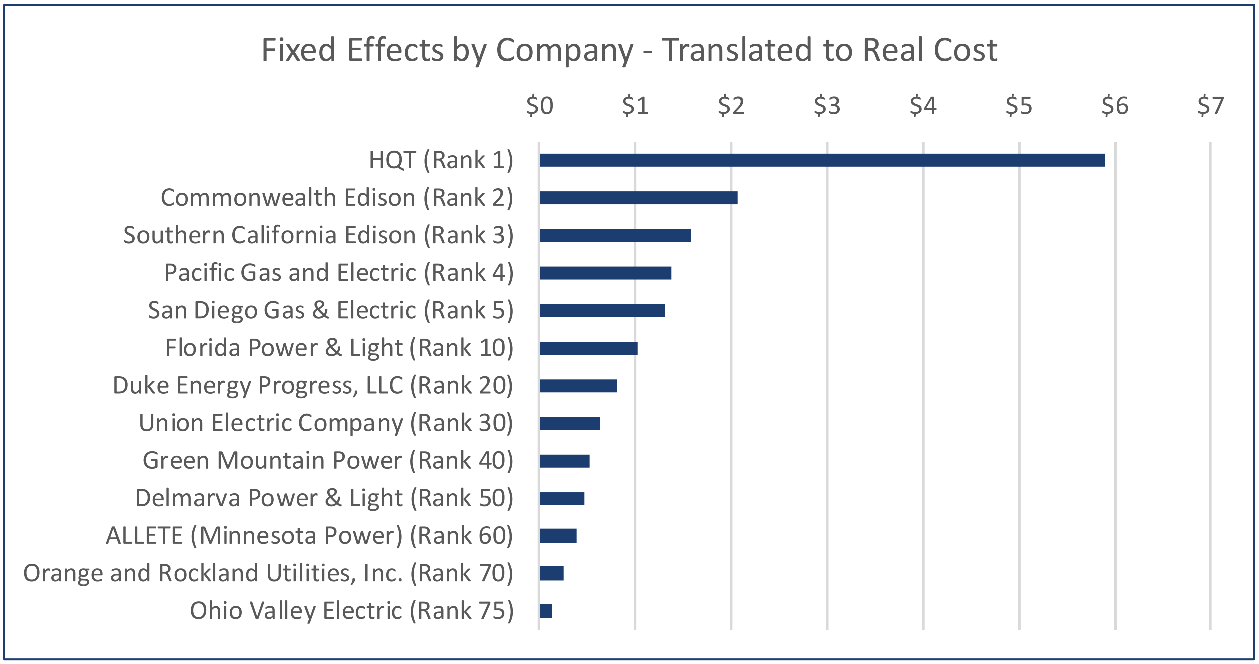
Figure 1 provides a good representation of the fundamental difference between Brattle and PEG's cost benchmarking analysis. We view the unobserved heterogeneity (cost differences) represented in the picture between HQT and Commonwealth Edison as being the result of factors that are unique to HQT and outside the firm's control. PEG, on the other hand, views the cost difference as due entirely to firm inefficiency. PEG confirms this point in response to Brattle question 5.5 where PEG suggests that HQT's constant term should not be used when making predictions.[45] Importantly, PEG does not discuss the basis of such large inefficiencies on the part of HQT nor where the failure within the company to operate efficiently emanates from.

---

[44] Since the dependent variable in the total cost regression is the logarithm of real cost, the costs in Figure 1 are calculated by taking the exponential of the fixed effects for the respective companies.

[45] We discuss this point in detail below in III.A.7.

FIGURE 1: HQT AND SAMPLE UNOBSERVED HETERGENEITY AND COSTS ($ MILLIONS)



5. Differences in Brattle and PEG results explained by choice of estimator

We use PEG's data to estimate correct econometric models and use the results to benchmark HQT costs. We do not make any changes to PEG's capital specification, O&M costs, common costs, output measures, sample companies and all other differences between the Brattle and PEG studies. We show that the correct econometric model with PEG's data and approach does not support PEG's conclusion that HQT is a poor performer.

Table 13 provides the summary of cost-benchmarking results based on Brattle's replication of PEG's analysis as well as the application of the fixed effect model to PEG's benchmarking dataset. The first three columns in the table provides the average difference in actual and predicted costs for HQT using PEG's preferred OLS approach. The average difference for the 2017 and 2019 period, which was provided in PEG's February report, showed that HQT's actual costs are considerably higher than those predicted by the benchmarking model. The next three columns in the table provide the results from using a fixed effects approach on PEG's benchmarking dataset. For both, the long-run and short-run period, the average differences for total costs, capital costs and O&M using the fixed effects estimator are much lower. For the long-run period, there is close to no difference in costs. The average cost difference continues to lie in the +/-10% band for the short-run period, much lower than those obtained from the OLS estimator.

TABLE 13: COMPARISON OF PEG'S BENCHMARKING RESULTS: OLS VS. FIXED-EFFECTS

	OLS			Fixed Effects		
	Total Costs	Capital Costs	O&M Costs	Total Costs	Capital Costs	O&M Costs
2008 - 2019	74.1%	61.3%	124.5%	-0.5%	-0.5%	-2.1%
2017 - 2019	67.4%	54.8%	121.1%	-7.1%	-8.2%	-1.1%

Note: This analysis uses the same specifications as laid out by PEG in the February report and workpapers.

Similarly, Brattle conducted a sensitivity of our econometric analysis using the OLS estimator that PEG employed for the benchmarking study to determine the impact it would have on our conclusions. As discussed above, we have already shown that the use of OLS on our and PEG's data is incorrect; we are providing this analysis to show the impact on using the incorrect estimator. The specifications we used are the same as those described in our Direct Report with the only difference being that we use the incorrect OLS estimator instead of the correct fixed effects estimator. Table 14 compares the results from the two models on Brattle's benchmarking data.

TABLE 14: BRATTLE COST-BENCHMARKING RESULTS USING OLS

	OLS			Fixed Effects		
	Total Costs	Capital Costs	O&M Costs	Total Costs	Capital Costs	O&M Costs
2001 - 2019	114.3%	118.3%	68.1%	-1.7%	-1.1%	-8.5%
2005 - 2019	114.4%	122.2%	57.7%	-2.8%	1.9%	-20.8%
2010 - 2019	111.4%	123.1%	43.5%	-6.0%	2.5%	-35.2%

Note: This analysis uses the same data and specifications as laid out by Brattle in the July report.

As is the case with Brattle's replication of PEG's benchmarking analysis, the average differences in costs obtained from the incorrect OLS approach are dramatically different than the fixed effects estimator. The OLS results show that actual total costs for HQT are more than double those predicted by the model while the fixed effects estimator shows that cost differences are within the +/-10% range.

From the results presented in Table 13 and Table 14, it is evident that the vast differences in conclusions by PEG and Brattle are driven primarily by the choice of estimators. The differences in conclusions are generally not driven by the underlying data, TFP assumptions, or methodologies.

6. Brattle's benchmarking results are robust to different specifications and TFP assumptions

We have conducted sensitivity tests on our econometric cost-benchmarking analysis in response to some of PEG's comments about our work.

1. **Peak Demand definition:** Brattle uses the same peak demand variable in both the productivity and benchmarking study, whereas PEG uses the monthly peak demand variable in the productivity study and the transmission system peak demand variable in the benchmarking study. In PEG's critique of our work, they state[46]:

   > **"**In Brattle's sample, the transmission system peak is about 11% higher on average from 2004-2019, and about 5%-8% higher on average for recent years. Brattle's use of monthly peak in benchmarking therefore tends to help their client"

   In this sensitivity, we use the transmission system peak demand in the benchmarking study to test the robustness of Brattle's conclusions. As can be seen in Table 15, using the alternative peak demand definition in our benchmarking has practically no impact on our benchmarking conclusions. HQT's actual costs are still below predicted costs. Over the entire period actual costs are now -1.0% below predicted costs compared to -1.7% when using monthly peak demand.

2. **Removal of selected O&M costs:** While Brattle includes all O&M costs in its productivity and benchmarking study, PEG removes three FERC accounts from transmission O&M expenses in the productivity study – FERC Accounts 561.1 to 561.8, 565 and 566. We remove these expenses in the benchmarking dataset here to test the robustness of the benchmarking results. As can be seen in Table 15, removal of these accounts does not have a significant impact on our benchmarking conclusions. HQT's actual costs are still below predicted costs. Over the entire period, actual costs are now -0.9% below predicted costs compared to -1.7% when the three FERC accounts were included.

3. **Translog Specification:** This involves the use of quadratic and second-order interactions for the output scale variables in the econometric benchmarking regressions. We modify the preferred specifications described in Brattle's direct report to include these second-order and interactions terms to gauge any change in the benchmarking results. As can be seen in Table 15, using the translog specification has little impact on our benchmarking conclusions. HQT's actual costs are still below predicted costs. Over the entire period, actual costs are now -1.6% below predicted costs compared to -1.7%.

4. **Geometric Decay Specification:** Brattle uses the One-Hoss-Shay approach to calculate capital stock while PEG uses the Geometric Decay. In its Direct Report (p. 60), PEG alleges that one hoss shay is unsuitable for benchmarking purposes. Here we re-do our benchmarking analysis by using the Geometric Decay approach instead. This also involves the use of Net Transmission plant in the calculation of capital stock for the benchmark year.[47] As can be seen in Table 15, the use of

[46] *See* page 18 of PEG's Commentary on Brattle's Empirical Study.

[47] *See* Page IV-37 of July Brattle Report.

geometric decay improves HQT's cost performance. Over the entire period, actual costs are now -1.9% below predicted costs compared to -1.7% when we used one hoss shay.

TABLE 15: BRATTLE HQT TOTAL COST-BENCHMARKING SENSITIVITIES

	Brattle Base Case	Transmission System Peak Demand	Selected O&M Costs Removed	Translog Specification	Geometric Decay Capital
2001 - 2019	-1.7%	-1.0%	-0.9%	-1.6%	-1.9%
2005 - 2019	-2.8%	-1.6%	0.8%	-2.1%	-6.1%
2010 - 2019	-6.0%	-5.2%	0.1%	-4.7%	-12.4%

Note: The results in the table reflect the average differences between HQT's actual costs and predicted costs for the respective periods. The selected O&M costs removed refer to FERC Form 1 accounts 561.1 – 561.8, 565 and 566.

7. Responses to PEG's criticism of panel data models

In its Commentary Report (p. 20), PEG describes the fixed effects estimator as a two-step process. The first step being to transform the data by subtracting "each company's mean value for cost and business condition variables (e.g., transmission line length) from the company's corresponding year value."[48] The second step is to estimate the transformed data by OLS. PEG then asserts that the first step data transformation renders the fixed effect estimator unsuitable for cost-benchmarking because "[t]he variation between companies in the value of the variables is ignored," and that Brattle's "models therefore effectively predict how the Company's cost varies from year to year around its average cost given the changes in the values of the business conditions it faced."

The data transformation that PEG describes above—and in which it concludes is a fatal flaw to cost-benchmarking—is *not* required to implement the fixed effects model. An alternative to transforming the data is to keep the data as given, add dummy variables for each company in the sample and run OLS. The resulting parameters *are identical* to the parameters when the data are time-demeaned—*i.e.*, they are identical to the fixed-effects parameters. Had PEG added company dummy variables to its OLS model it would have obtained the fixed effects parameters. Given the significant differences among the companies in the sample, and the many reasons that PEG itself identified as making HQT unique, we believe it is eminently reasonable to included company-specific dummy variables to control for those differences. Had PEG done so, it would have estimated a fixed effects model and its cost-benchmarking results would have been very different, as we showed above in Section III.A.5.

Even without the dummy variable approach to fixed effects, time-demeaning the data does not mean that the model effectively predicts how costs vary from year to year but not across firms. The fixed effect slope coefficients capture any variation in how cost responds to included variables. For example,

[48] In econometrics parlance, this is referred to as having "time-demeaned" the data.

if there are differences in companies in output scale economies, the resulting coefficients would reflect this variation, *i.e.*, the coefficient would be something like an average across companies and not company-specific scale economies. Thus, we disagree with PEG's assertion (pp. 21-22) that "fixed effects ignores the valuable information contained in between variation when estimating model parameters."

Finally, in response to the Régie 2.3, PEG acknowledges the use of panel data and estimators for econometric cost benchmarking and points to several non-academic reports before regulators to support its view that including fixed effects in cost prediction is not typical. These studies were used for a different purpose and not for assistance in setting stretch factor in a revenue cap plan. Differences in the companies within the sample were not as pronounced as the differences between HQT and its U.S. counterparts, which explain why in the jurisdictions referenced differences in efficiency scores among different estimators were similar. There was nothing to give the consultants pause when examining efficiency conclusions from different approaches, unlike in this case. Moreover, in the Australian case, the consultants acknowledge that counting all the fixed effects as inefficiencies requires an assumption that cost inefficiencies are invariant over time, which is a reason they include alternative techniques that do not rely on inefficiencies being the fixed effects.

The view that the fixed effects are the inefficiencies in a cost benchmarking study is belied by the academic literature discussed above and reflects a dated view of the literature. Moreover, if one ascribes the fixed effects as representing all inefficiencies, the implication is that inefficiencies are constant over time and the firm cannot improve—a proposition that is unreasonable and goes against our understanding of firm behavior.

8. Additional concerns with PEG's econometric analysis

- **Initial PEG methodology and approach**

In its justification for using pooled OLS, in its Direct Report (p. 101) PEG states:

> "To diffuse controversy in this proceeding, we have adopted in this study the general approach that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors available in the Stata statistical software package."

In its Commentary Report (p. 19), PEG states:

> "In Ontario *MRI* proceedings, Hydro One witness Fenrick has favored an ordinary least squares estimator. The witness for Board Staff (PEG) has in these same proceedings favored a feasible generalized least squares estimator that corrected for autocorrelation and groupwise heteroskedasticity. In this proceeding, we elected to use an ordinary least squares estimator that is similar

> to Mr. Fenrick's in the hope of avoiding an *arcane methodological controversy*." [Emphasis added]

As we have shown in this section, the difference in HQT cost-benchmarking results when using OLS and fixed effects (and between OLS and the random effects estimator) is significant. It is much more important than the differences in results emanating from differences in sample companies, capital specification, inclusion or exclusion of certain O&M costs, inclusion or exclusion of common costs and output measures. It is not an "arcane methodological controversy".

- **Comments on predictions vs. benchmarking**

Finally, in its Commentary Report (p. 21), in an additional critique of fixed effects PEG states that "Brattle's methodology would be more useful were the goal of the econometric research to predict HQT's cost." Both Brattle and PEG's cost-benchmarking methodology is to estimate the best econometric cost models possible, use the model to *predict* HQT's costs and compare predicted costs to actual costs. On p. 18 of its Commentary Report, three pages prior, PEG describes its cost-benchmarking methodology as:

> "We discussed the econometric approach to cost-benchmarking on pages 28-33 and pages 100-101 of our February report, explaining that econometric cost models approximate the relationship between cost and external business conditions. These conditions are sometimes called cost "drivers". The parameters for each driver are estimated using a sample of historical data on the costs of utilities and the business conditions that they faced. *Predictions of cost that are made when the model is fitted with a utility's values for the business condition variables are then used as benchmarks*. [Emphasis added]

Clearly, the goal of the cost-benchmarking exercise is to *predict* HQT's costs.

- **Mis-measurement of substation data**

PEG downloaded data only for two years (2009 and 2019) and interpolated for the intervening years with a straight-line method. This resulted in mis-measurement of this independent variable, where for many years the number of substations appearing in its data set included *fractional* number of substations. Data errors in the independent variable can create bias.

- **PSE' forestation and construction standard index**

PEG utilized PSE's forestation and construction standard index variables in its econometric models. However, PSE did not create those variables for HQT. In its Commentary Report (p. 101), PEG indicated:

> "PSE has used its forestation variable in several power distribution benchmarking studies. It is inefficient to develop a variable of similar quality when its use in this proceeding can be purchased at a reasonable price from PSE. To save money we used the value for the forestation variable which PSE had assigned to Hydro One Networks in a distribution MRI proceeding."

With respect to the construction standard index, PEG similarly states (PEG Commentary Report p. 102):

> "PSE developed its construction standards index for use in its Hydro One Transmission benchmarking study. To save money we used the value for the construction standards index which PSE had assigned to Hydro One Networks in that study."

PEG fails to provide evidence that these are reasonable assumptions, and given the reasons that PEG itself mentioned that make HQT unique, it is unlikely that PSE's scores for HQT would have been the same. This introduces an additional source of bias in PEG's benchmarking analysis.

B. Stretch factor

In its Direct Report (p. 96), PEG proposed that the stretch factor "should be no less than 0.60%". This conclusion was based on results of PEG's OLS approach and the benchmarking thresholds set by the OEB in a prior formula rate case. The table below provides the ranges adopted by the OEB in its 4th Generation Incentive Regulation.

TABLE 16: OEB 4TH GEN IR STRETCH FACTORS

Group	Cost Performance Range (Actual vs. Predicted)	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within ±10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

Source: EB-2010-0379, Report of the Board, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors."

However, it is evident from Table 13 that the average cost differences calculated in the benchmarking exercise are highly sensitive to the choice of estimator used. A fixed effects approach on PEG's own benchmarking dataset and specification results in significantly lower cost differences between HQT's actual and predicted costs. Relatedly, the thresholds set by the OEB would dictate that a 0.30% stretch factor be used.

Finally, in its Direct Report (p. 96) PEG indicates that:

> "Based on our incentive power research, we recommend a stretch factor adder of at least 0.1% should the Régie base X on productivity results for the full sample period. An adder of at least 0.3% is recommended if X is based on results for the most recent fifteen years."

In response to Brattle question 6.1, PEG provided a link to one of its report for support of the recommended adders. However, that report provides insufficient evidence on how to translate characteristics of specific regulatory regimes into specific stretch factors.

Appendix A: Literature review of use of panel data models in econometric benchmarking

TITLE	AUTHOR	JOURNAL	COMMENT
The measurement and sources of technical inefficiency in the Indonesian weaving industry	Pitt and Lee (1981)	*Journal of Development Economics*	Uses panel data and a random effects model to measure inefficiency among 50 Indonesian textile firms in the 1970s.
Production frontiers and panel data	Schmidt and Sickles (1984)	*Journal of Business and Economic Statistics*	Uses several estimators for estimating firm inefficiency in the airline sector, including the fixed effects model and the random effects model. The authors specifically recommend against using OLS as the random effects model is preferred.
Estimation of technical inefficiency in panel data models with firm– and time-specific effects	S.C. Kumbhakar (1991)	*Economics Letters*	Theoretical discussion. Uses panel data models and develops methods to measure technical inefficiency using both random and fixed effects treatment of firm and time effects.
Efficiency measurement in Swedish dairy farms: An application of rotating panel data, 1976-88	Kumbhakar and Heshmati (1995)	*American Agricultural Economics Association*	Apply random effects model to measure efficiency in Swedish Dairy Farms. The authors cite the use of fixed effect as an appropriate choice, but select the random effects because they are dealing with "rotating" panel as farms enter and leave their sample throughout the period.
Confidence statements for efficiency estimates from stochastic frontier models	Horrace and Schmidt (1996)	*Journal of Productivity analysis*	Uses maximum likelihood, random effects (GLS) and fixed effects in a panel to estimate inefficiency in various sectors. The sectors included a panel of Indonesian rice farms and a panel of Texas electric utilities.
Regulation and measuring cost efficiency with panel data models: application to electricity distribution utilities	Farsi and Filipino (2004)	*Review of Industrial Organization*	Uses a panel data of 59 electric distribution utilities in Switzerland over a period of 9 years and obtains efficiency rankings obtained from Random Effects and Fixed Effects models.

Distinguishing between heterogeneity and inefficiency: stochastic frontier analysis of the World Health Organization's panel data on national health care systems	Greene (2004)	*Health Economics*	Fitted a fixed-effects frontier model to a panel of 191 countries over the period 1993-1997 to examine efficiency of health care outcomes.
Reconsidering heterogeneity in panel data estimators of the stochastic frontier model	Greene (2005)	*Journal of Econometrics*	Theoretical discussion with application to banking. Uses several estimators including fixed effects (OLS with unit dummies), "true" fixed effects, random effects and others.
Panel estimators and the identification of firm-specific efficiency levels in parametric, semiparametric and nonparametric settings	Robin C. Sickles (2005)	*Journal of Econometrics*	Theoretical with application to U.S. Banking. The paper analyzes a number of competing approaches to modeling efficiency in panel studies. The specifications considered include the fixed effects, the random effects, the Hausman–Taylor random effects stochastic frontier, and the random and fixed effects stochastic frontier with an AR(1) error.
Efficiency measurement in network industries: Application to the Swiss railway companies	Farsi, Filippini and Greene (2005)	*Journal of Regulatory Economics*	Uses panel data to estimate cost functions for Swiss railways companies. Authors utilize several estimators including fixed effects and random effects. Uses the Hausman test confirm firm-specific effects are correlated with explanatory variables.
Application of panel data models in benchmarking analysis of the electricity distribution sector	Farsi, Filippini and Greene (2006)	*Annals of Public and Cooperative Economics*	Uses panel data to estimate cost functions of 59 electricity distribution companies in Switzerland. Authors utilize GLS, true random effects, and MLS.
An econometric assessment of telecommunications prices and consumer surplus using panel data	Hausman and Ros (2013)	*Journal of Regulatory Economics*	Fixed and Mobile telecommunications
Estimating efficiency effects in a panel data stochastic frontier model	Paul and Shankar (2020)	*Journal of Productivity Analysis*	Theoretical with application to farming