Réponses de AQCIE-CIFQ/PEG à Demande de renseignements du Transporteur (The Brattle Group)

Productivity Study

1. Sample selection

Reference: PEG Report p. 67: "FERC Form 1 was the source of data on transmission costs, network characteristics, and peak demand of U.S. electric utilities which we used in our research."

Reference: PEG Report p. 67: "Data for 51 U.S. power transmitters were used in our productivity trend research."

Reference: PEG Report p. 59: "Expand the sample from PEG's Ontario study to include some additional U.S. power transmitters that face business conditions that are similar to HQT's (e.g., Central Maine Power)."

Demande(s)

1.1 For the most recent year of PEG's productivity study, how many power transmitters filed transmission costs, network characteristics and peak demand at the FERC through FERC Form 1?

Réponse :

In 2019, 205 companies filed the Form 1. Of these, 172 reported having transmission plant in service. Of these, 129 reported (both) miles of transmission line and peak demand data.

1.2 Please explain PEG's sample selection methodology for the productivity study, including the criteria PEG used to include (or exclude) transmitters.

Réponse :

PEG developed a transmission cost research sample in two recent projects for Ontario Energy Board ("OEB") staff. Our work for the OEB was to evaluate evidence sponsored by Hydro One. Their expert had his own criteria for the exclusion of companies which resulted in a sample that was broadly sensible in our opinion. PEG did not make a priority of expanding this sample for the HQT study. PEG started the HQT work with the sample from their previous Ontario work but took the opportunity to remove a few more companies. In the opinion of PEG, the incremental benefit of some additional data points did not outweigh the cost of the additional data corrections and analysis involved and would not have resulted in a meaningful difference in the results of the study.

1.3 Brattle used a sample of 74 companies for its productivity study while PEG used 51. The table below depicts the companies that Brattle and PEG included in their productivity studies.

Table 1.3

Company	In Brattle Model	In PEG Model	In Both
Alabama Power Company	Yes	Yes	Yes
ALLETE (Minnesota Power)	Yes	Yes	Yes
Arizona Public Service Company	Yes	Yes	Yes
Atlantic City Electric Company	Yes	Yes	Yes
Avista Corporation	Yes	Yes	Yes
Baltimore Gas and Electric Company	Yes	Yes	Yes
Black Hills Power, Inc.	Yes	No	No
Central Hudson Gas & Electric Corporation	Yes	Yes	Yes
Central Maine Power Company	Yes	No	No
Cleco Power LLC	Yes	Yes	Yes
Cleveland Electric Illuminating Company	Yes	No	No
Commonwealth Edison Company	Yes	Yes	Yes
Connecticut Light and Power Company	Yes	Yes	Yes
Consolidated Edison Company of New York, Inc.	Yes	Yes	Yes
Dayton Power and Light Company	Yes	No	No
Delmarva Power & Light Company	Yes	Yes	Yes
Dominion Energy South Carolina, Inc.	Yes	No	No
Duke Energy Carolinas, LLC	Yes	Yes	Yes
Duke Energy Florida, LLC	Yes	Yes	Yes
Duke Energy Indiana, LLC	No	Yes	No
Duke Energy Ohio, Inc.	No	Yes	No
Duke Energy Progress, LLC	Yes	Yes	Yes
Duquesne Light Company	Yes	Yes	Yes
El Paso Electric Company	Yes	Yes	Yes
Empire District Electric Company	Yes	Yes	Yes
Entergy Arkansas, LLC	Yes	No	No
Entergy Mississippi, LLC	Yes	No	No
Entergy New Orleans, LLC	Yes	No	No
Evergy Kansas South, Inc.	Yes	No	No
Evergy Metro, Inc.	Yes	No	No
Florida Power & Light Company	Yes	Yes	Yes
Georgia Power Company	Yes	No	No
Green Mountain Power Corporation	Yes	No	No
Gulf Power Company	Yes	Yes	Yes
Idaho Power Company	Yes	Yes	Yes
Indianapolis Power & Light Company	Yes	Yes	Yes
Jersey Central Power & Light Company	No	Yes	No
Kansas City Power & Light	No	Yes	No
Kansas Gas & Electric	No	Yes	No
Kentucky Utilities Company	Yes	Yes	Yes
Louisville Gas and Electric Company	Yes	Yes	Yes
MDU Resources Group Inc.	Yes	No	No
Mississippi Power Company	Yes	Yes	Yes
Monongahela Power Company	Yes	Yes	Yes
Nevada Power Company	Yes	No	No
New York State Electric & Gas Corporation	Yes	Yes	Yes
Niagara Mohawk Power Corporation	Yes	Yes	Yes
Northern Indiana Public Service Company	Yes	No	No
Northern States Power Company – MN	Yes	Yes	Yes
Northern States Power Company – WI	Yes	No	No
NSTAR Electric Company	Yes	No	No
Ohio Valley Electric Corporation	Yes	No	No
Oklahoma Gas and Electric Company	Yes	Yes	Yes
Orange and Rockland Utilities, Inc.	Yes	Yes	Yes
Otter Tail Corporation	Yes	No	No
Pacific Gas and Electric Company	Yes	No	No
PacifiCorp	Yes	Yes	Yes
PECO Energy Co.	Yes	Yes	Yes
Portland General Electric Company	Yes	No	No
Potomac Edison Company	Yes	No	No
Potomac Electric Power Company	Yes	Yes	Yes
PPL Electric Utilities Corporation	Yes	No	No
Public Service Company of Colorado	Yes	Yes	Yes
Public Service Company of New Hampshire	Yes	No	No
Public Service Company of New Mexico	Yes	No	No
Public Service Company of Oklahoma	Yes	No	No
Public Service Electric and Gas Company	Yes	Yes	Yes
Puget Sound Energy, Inc.	Yes	No	No
Rochester Gas and Electric Corporation	Yes	Yes	Yes
San Diego Gas & Electric Company	Yes	Yes	Yes
Sierra Pacific Power Company	Yes	No	No
South Carolina Electric & Gas	No	Yes	No
Southern California Edison Company	Yes	Yes	Yes
Southern Indiana Gas and Electric Company	No	Yes	No
Southwestern Electric Power Company	Yes	No	No
Southwestern Public Service Company	Yes	Yes	Yes
Tampa Electric Company	Yes	Yes	Yes
Tucson Electric Power Company	Yes	Yes	Yes
Union Electric Company	Yes	Yes	Yes
United Illuminating Company	Yes	No	No
West Penn Power Company	Yes	Yes	Yes

1.3.1 Please confirm the companies highlighted in the table were not used in the PEG study.

Réponse :

Not confirmed. The above table contains some errors that will help resolve some of the differences. The following pairs of companies are identical.

- **Dominion Energy South Carolina = South Carolina Electric and Gas**
- **Evergy Kansas South = Kansas Gas and Electric**
- **Evergy Metro = Kansas City Power and Light**

Other than these companies, the statement is confirmed.

1.3.2 Please confirm that Pacific Gas and Electric was not used in the PEG study.

Réponse :

This statement is confirmed.

1.3.3 For 2019, what size rank (in terms of transmission length and peak demand) would Pacific Gas and Electric have had in PEG's sample, had it been included?

Réponse :

PG&E would have ranked second and sixth in the sample as measured by line length and peak demand.

1.3.4 Please provide the specific reason(s) why Pacific Gas and Electric was not included in the productivity study. Also, specifically indicate whether PEG has calculated the 1964 benchmark capital for Pacific Gas and Electric?

Réponse :

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.

1.3.5 Please confirm that Georgia Power Company was not used in the PEG study.

Réponse :

The statement is confirmed.

1.3.6 For 2019, what size rank (in terms of transmission length and peak demand) would Georgia Power Company have had in PEG's sample, had it been included.

Réponse :

Georgia Power would have ranked fourth and second in the sample as measured by line length and peak demand.

1.3.7 Please provide the specific reason why Georgia Power Company was not included in the productivity study. Also, specifically indicate whether PEG has calculated the 1964 benchmark capital for Georgia Power Company?

Réponse :

Georgia Power was involved in a merger with Savannah Electric & Power. It was not included in Mr. Fenrick's work presumably because the appropriate adjustment to the historical data needed to include the company was not done. PEG based its sample on the Fenrick sample and did not make a priority of adding companies to the sample for this project.

1.3.8 For each of the remaining companies in the table above that was in the Brattle study but was not in the PEG study, please provide the specific reasons why PEG did not use the company in its productivity study. Also, specifically indicate whether PEG has calculated the 1964 benchmark capital for each company.

Réponse :

Please see Attachment PEG-Brattle-1.3.8, which is based on Table 1.3 provided above. PEG added two columns. The first shows the companies in the 2019 Fenrick study sponsored by Hydro One Networks. The second column describes why each company was excluded.

1.3.9 What steps did PEG undertake during its study to ascertain whether the exclusion of transmitter companies that provide FERC Form 1 data biased its productivity analysis?

Réponse :

PEG tested the sensitivity of Brattle's results to the sampled companies by excluding companies that PEG did not have in its study. The goal was to determine how much different the results would be with a reduced sample. PEG started by removing the companies for which Brattle did not adjust for mergers (Green Mountain, Georgia Power, NSTAR) and those that had clear data problems (PG&E and Nevada Power). Removing these 5 companies resulted in the MFP trend *rising* from 0.09% to 0.21% for the full Brattle sample period. This was not unexpected due to the known problems with these companies.

To assess the potential bias from the exclusion of companies without large data issues, PEG then excluded all other companies from Brattle's sample which were not included in their study. The exclusion of the additional companies only resulted in an increase in the MFP trend from 0.21% to 0.31%. Because the direction of the change was to raise the productivity trend, PEG concluded that the potential addition of companies in the Brattle work without clearly problematic data to its own study would not have lowered the MFP trend toward the Brattle value.

Reference: PEG Rebuttal Report p. 30: "While some of the extra Brattle companies may have sound data, others have problematic data. For example, several have implausible surges in miscellaneous transmission expenses. Others have problematic data for one or more business condition variables."

1.3.10 Please provide the names of the companies that have implausible surges in miscellaneous transmission expenses.

Réponse :

The following additional companies in PEG's productivity study were deemed to have implausibly large surges in miscellaneous transmission expenses: Commonwealth Edison, Kansas Gas and Electric, Oklahoma Gas and Electric, PECO Energy, San Diego Gas and Electric, and Southern California Edison.

1.3.11 Please provide the names of the companies that have problematic data for one or more business condition variables.

Réponse :

Please see the response to question 1.3.8 for a list of companies and reasons for exclusion. Many companies included in the Brattle work but excluded from the PEG work were also excluded by the Hydro One witness in Ontario according to his own criteria which included missing or problematic business condition data. The recollection of PEG is that the most common reason for exclusion was missing or problematic substation data.

2. Transmission Operation & Maintenance costs (O&M)

Reference: PEG Report p. 69: "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 FERC Form 1 categories excluded on these grounds were Transmission of Electricity by Others (account 565), Load Dispatching (accounts 561.1-561.8), Miscellaneous Transmission Expenses (566), and Regional Market Expenses (accounts 575 and 576)."

Demande(s)

2.1. For each account, (with the exception of accounts 575 and 576) please provide the share of expenses as a percent of total transmission O&M expenses (accounts 560-574) in PEG's study.

Réponse :

The following table contains the requested information for the sum of all sampled utilities for 2019.

Average Percent of Total CNE by Account: 2019

FERC Account	Percent of Transmission CNE by FERC Account
560	6.1%
561.1	**1.5%**
561.2	**4.0%**
561.3	**1.1%**
561.4	**5.0%**
561.5	**0.9%**
561.6	**0.1%**
561.7	**0.2%**
561.8	**2.7%**
562	3.7%
563	1.7%
564	0.2%
565	**25.0%**
566	**15.4%**
567	3.4%
568	1.1%
569	0.5%
569.1	0.2%
569.2	1.8%
569.3	0.4%
569.4	0.0%
570	7.3%
571	16.3%
572	0.8%
573	0.8%
Percent Excluded	55.8%

2.2. What percent of total transmission O&M expenses (accounts 560-574) has PEG excluded in its transmission productivity study?

Réponse :

Please see the response to question 2.1.

2.3. Please determine the growth rate for accounts 561, 565 and 566 over the period and compare to the growth rate for the remaining transmission O&M accounts (not including accounts 561, 565, 566).

Réponse :

The average annual growth rate of the included O&M cost categories over the full sample period was 3.56%. The sample average annual growth rate of the excluded items was a much higher 8.32%.

2.4. Please recalculate the total factor productivity trends and the CNE productivity trends including accounts 561.1-561.8, 565, 566.

Réponse :

These trends are reported in the following table. It can be seen that *CNE* productivity growth was substantially more negative over the full sample period but less negative over the last fifteen years.

US Transmission Productivity Results: No Excluded CNE

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index				Productivity			
		Summary	O&M	Transmission Capital	Allocated General Plant	MFP	O&M	Transmission Capital	Allocated General Plant
1996	1.2%	0.3%	2.5%	-0.9%	1.2%	0.9%	-1.2%	2.2%	0.0%
1997	0.9%	0.4%	5.0%	-1.2%	-4.4%	0.5%	-4.1%	2.1%	5.3%
1998	2.2%	2.6%	14.2%	-1.9%	2.1%	-0.3%	-12.0%	4.2%	0.1%
1999	2.8%	0.0%	7.5%	-1.9%	-2.3%	2.8%	-4.7%	4.6%	5.1%
2000	0.4%	-0.1%	0.4%	-1.3%	10.5%	0.5%	0.0%	1.7%	-10.1%
2001	1.8%	2.4%	6.0%	-0.9%	13.4%	-0.6%	-4.3%	2.6%	-11.6%
2002	0.7%	-2.1%	-5.6%	-0.4%	-4.3%	2.8%	6.2%	1.0%	4.9%
2003	1.4%	-0.2%	1.3%	-0.7%	1.2%	1.6%	0.1%	2.0%	0.2%
2004	0.6%	6.8%	18.5%	-0.2%	-1.5%	-6.1%	-17.8%	0.9%	2.1%
2005	2.7%	4.8%	10.6%	0.1%	-1.8%	-2.1%	-7.9%	2.7%	4.5%
2006	2.3%	-0.2%	-0.7%	0.4%	-0.8%	2.5%	3.0%	1.9%	3.1%
2007	0.0%	-1.9%	-2.5%	1.4%	0.2%	2.0%	2.5%	-1.3%	-0.2%
2008	0.3%	3.4%	5.6%	1.2%	1.0%	-3.1%	-5.3%	-0.9%	-0.7%
2009	-0.1%	-0.4%	-3.6%	2.5%	2.2%	0.3%	3.5%	-2.6%	-2.3%
2010	0.7%	3.5%	6.8%	2.2%	-1.4%	-2.8%	-6.1%	-1.5%	2.0%
2011	0.3%	1.2%	-0.8%	2.9%	2.9%	-0.9%	1.2%	-2.5%	-2.6%
2012	0.4%	1.6%	0.8%	2.1%	5.5%	-1.2%	-0.3%	-1.7%	-5.1%
2013	0.3%	4.5%	3.0%	4.9%	6.2%	-4.2%	-2.6%	-4.6%	-5.9%
2014	1.2%	2.9%	-2.9%	5.0%	0.4%	-1.7%	4.1%	-3.8%	0.9%
2015	0.4%	5.8%	5.6%	5.9%	1.3%	-5.5%	-5.3%	-5.5%	-0.9%
2016	0.8%	4.2%	0.4%	4.7%	9.6%	-3.4%	0.4%	-3.9%	-8.8%
2017	0.1%	3.6%	2.2%	3.7%	2.2%	-3.5%	-2.1%	-3.6%	-2.2%
2018	0.8%	6.0%	11.0%	3.1%	3.9%	-5.2%	-10.1%	-2.3%	-3.1%
2019	0.7%	0.8%	-4.9%	3.4%	6.6%	-0.1%	5.6%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**2.08%**	**3.34%**	**1.42%**	**2.25%**	**-1.12%**	**-2.38%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**2.66%**	**2.03%**	**2.90%**	**2.54%**	**-1.93%**	**-1.29%**	**-2.16%**	**-1.80%**

Reference: PEG 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.

2.5 What dispatching expense account is PEG specifically referring to in the statement?

Réponse :

Please see the response to question 2.11.

2.6 Please list the companies that have, in fact, inconsistently reported the expenses referred to in the statement.

Réponse :

PEG's concerns with the transmission *CNE* data were discussed on some length on

pages 63 to 65 of their February report. This discussion was based on a detailed analysis of the *CNE* cost data of sampled transmitters. The spreadsheet that we used in this analysis can be found in Attachment PEG-Brattle-2.6 Confidential. Please note the following.

- **Many utilities reported a surge in transmission by others expenses.**
- **Six members of ISOs or RTOs (e.g., Commonwealth Edison, Kansas Gas and Electric, Oklahoma Gas and Electric, PECO Energy, San Diego Gas and Electric, and Southern California Edison) reported sharp increases in miscellaneous transmission expenses.**
- **Three members of ISOs or RTOs (Commonwealth Edison and PECO Energy, and Southern California Edison) reported sharp increases in dispatch-related expenses. These seemed to be transfers from miscellaneous transmission expenses. Many other companies reported smaller but material jumps in dispatch related expenses. The salient cause was scheduling, system control and dispatching expenses from an ISO or RTO.**
- **Nevada Power reported a surge in transmission rents.**

Based on this analysis, PEG decided to exclude six companies (indicated in brown in the attachment) from the econometric model estimation and to exclude transmission by others, miscellaneous transmission expenses, and accounts 561.1 to 561.8 from the productivity calculations.

2.7 Please provide evidence that, in fact, companies have inconsistently reported the expenses referred to in the statement.

Réponse :

Please see the response to question 2.6.

2.8 Does PEG believe that the inconsistent reporting is systematic among the companies that are members of ISO, or is it more or less random?

Réponse :

Yes.

2.9 If systematic, please describe the company characteristics that would make the inconsistent reporting more or less likely.

Réponse :

ISO members are most likely to have the problem but members do vary in their reporting.

Reference: PEG 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.”

Reference: PEG 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.”

2.10 Please list the companies that have, in fact, reported the expenses referred to in the statements inconsistently.

Réponse :

Please see the response to question 2.6.

Reference: PEG Report p. 65: "Whether or not utilities are ISO members, they have some discretion as to whether to report dispatch expenses in FERC Account 561 (Load Dispatching) under Transmission Expenses or FERC Account 556 (System Control and Load Dispatching) under Other Power Supply Expenses."

2.11 FERC Account 561 has subaccounts 561.1 – 561.8. Is it PEG's opinion that all of these subaccounts are "load dispatching"?

Réponse :

No. PEG used the term "load dispatching" in their report for all of accounts 561.1 – 561.8 because they are all subaccounts of the old account 561 which was titled "Load Dispatching". The intent was to identify the cost associated with operation of the transmission system as a system as opposed to the O&M associated with particular physical transmission assets. These system costs are those associated with tasks potentially assumed by ISOs and RTOs.

81	2. TRANSMISSION EXPENSES
82	Operation
83	(560) Operation Supervison and Engineering
84	(561) Load Dispatching
85	(562) Station Expenses
86	(563) Overhead Lines Expenses
87	(564) Underground Lines Expenses
88	(565) Transmission of Electricity by Others

2.12 If not, which ones do not involve load dispatching?

Réponse :

The accounts that do not involve load dispatching include those for planning and studies.

Reference: PEG Report p. 53: "The first of these proceedings (EB-2018-0218) considered an MRI for Hydro One Sault Ste. Marie, a small transmission subsidiary of Toronto-based Hydro One Networks which serves a region on the eastern shore of Lake Superior."

2.13 Please confirm that PEG's productivity study in the proceeding cited in the statement, excluded account 567, transmission rent expenses. If so, please provide an explanation for the change in methodology between that study and PEG's study for this proceeding on this issue and the reason for excluding transmission rent expenses in the proceeding cited in the statement but not in the current proceeding.

Réponse :

Problems with rent expense data could be addressed by either an adjustment to the sample or an adjustment to the reported expenses. In PEG's sample, the problem was limited to a single utility (Nevada Power) that owns a valuable transmission asset as part of a joint venture. The accounting problem is that this company has accounted for the cost of the assets it owns as rents. This means that the company's O&M expenses include a large amount of capital cost and this distorts the productivity and benchmarking results. In lieu of removing an additional cost category, PEG decided in their HQT study to exclude Nevada Power.

Reference: PEG Rebuttal Report (p. 13): "All three of these cost categories have also been affected by idiosyncratic reporting of costs incurred for the services of independent system operators and regional transmission organizations."

2.14 What steps did PEG undertake during its study to ascertain whether the alleged misreporting and inconsistencies associated with accounts 561.1- 561.8, 565, 566 are, in fact, occurring and significant?

Réponse :

Please see the response to question 2.6.

3. Capital

Reference: PEG Report p. 69: "Taxes (and franchise fees) were excluded, and no provisions were made for tax-related accelerated depreciation."

Reference: Laurits R. Christensen and Dale W. Jorgenson, "The Measurement of U.S. Real Capital Input 1929-1967," *Review of Income and Wealth* 1969, vol. 15(4).

Reference: PEG Report p. 98: "The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of the (transmission or general) plant that it and any predecessor utilities reported. We estimated the quantities of capital in that year by dividing these values, respectively, by triangularized weighted averages of 47 consecutive values of a regional Handy Whitman Index of power transmission construction cost and 16 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value."

Demande(s)

3.1 Is PEG's exclusion of taxes and lack of provision for tax-related accelerated depreciation consistent with the referenced article?

Réponse :

No. That article detailed a methodology for decomposing capital cost into a price and a quantity which included taxes.

3.2 By excluding taxes and tax-related accelerated depreciation, is it not the case that the capital prices actually experienced by PEG's sample companies are different than the capital price that PEG calculated?

Réponse :

Yes.

3.3 By excluding taxes and tax-related accelerated depreciation, is it not the case that the capital and the CNE shares actually experienced by PEG's sample companies are different than the capital and the CNE shares that PEG calculated?

Réponse :

Yes. This in turn would mean a lesser weight on capital quantity trends in the productivity study.

3.4 Please confirm that the Handy Whitman index tracks the price of gross additions to plant, not net additions.

Réponse :

This statement is confirmed. However, PEG uses the Handy Whitman Indexes to deflate the value of gross plant additions. In the case of the geometric decay method, in the first indexing or benchmark year a triangularized weighted average of the Handy Whitman Indexes is used to arrive at the average price at which earlier gross plant additions were made. When deflating net plant value, the issue is not that one is looking for a price index for so called net additions. All additions are gross additions. The challenge when implementing geometric decay is to calculate a net capital stock. The starting point for this calculation is the reported gross plant value less accumulated depreciation on the history of gross additions that are still in service and therefore show up in the company's accounts in the benchmark year. An assumption is made that that the quantity of capital in the benchmark year was accumulated in equal amounts over a period equal to the average service life of plant (e.g., 1 unit per year for 46 years). Under this assumption, the earliest plant has gross plant equal to HW x 1 and accumulated depreciation of 45/46 x HW which equals 1/46 x HW of net plant. Subsequent years will have 2/46, 3/46, etc. of net plant that will be observed in the benchmark year. It is this 1, 2, 3 … 46 pattern that is the source of the triangular weights in the formula. The Handy Whitman Index in the formula is meant to apply to gross additions even in the context of net stock calculations.

Reference: PEG Report p. 73: "For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute."

3.5 In a given year, did PEG use the same ROE for each company or was the ROE different for each company?

Réponse :

PEG used the same ROE for all US companies.

Reference: PEG Report pp. 72-73: "For debt we used the embedded average interest rate on long-term debt of a large group of electric utilities as calculated from FERC Form 1 data."

3.6 Did the "large group of electric utilities" include the same companies that are in PEG's data base?

Réponse :

The large group of utilities comprised most companies that filed the FERC Form 1 in a given year and had the required data for the calculation. All of the US utilities in PEG's study were included in the calculation of the embedded average interest rate.

3.7 Please describe the general approach used, identify the FERC form 1 accounts and provide the underlying workpapers supporting the approach.

Réponse :

The general approach is to calculate an average interest rate paid on long term debt. This was calculated as the ratio of interest on long term debt (account 427) to balance sheet values that correspond to that interest (accounts 221 and 224, bonds and other long-term debt). The data were screened to eliminate a few cases in which this ratio would result in an implausible interest rate, possibly due to timing issues in which only 1 month of interest is paid for a given year or a large amount of debt matured before year end in which a lot of interest was paid on very little outstanding debt at year end. The working papers are included as Attachment PEG-Brattle-3.7 Confidential. The effect on benchmarking results is minor because the same interest rates are used in both the capital cost and the capital price calculations. For the productivity work this only affects the weight that capital is given.

3.8 In a given year, did PEG use the same interest rate for each company?

Réponse :

The same interest rate was used for each US company.

Reference: PEG Report p. "The assumed 47-year average service life for transmission plant, 16-year average service life for general plant, 1.65 declining balance rate for equipment, and 0.91 declining balance rate for structures were used to set d."

3.9 Please confirm that in EB-2018-0218, PEG utilized a 46-year average service life.

Réponse :

This statement is confirmed.

3.10 Please provide an explanation for the different treatment of average service life in this proceeding and provide the evidence PEG relied upon to make the change.

Réponse :

PEG routinely upgrades its research methodology as new projects create the opportunity to do so cost-effectively.

3.11 Please confirm that in EB-2018-0218, PEG utilized a 1.65 declining balance rate for all capital equipment.

Réponse :

This statement is not confirmed. PEG used an alternative decay rate based on a 1.65 rate for equipment and 0.91 rate for structures. If the phrase "all capital equipment" in the question was not meant to include structures, then the statement is confirmed.

3.12 Please provide an explanation for the different treatment of the declining balance rate in this proceeding and discuss and provide the evidence PEG relied upon to make the change.

Réponse :

When possible, PEG prefers to use the service life information of the company being benchmarked as the basis of the decay rate calculations. This method keeps the calculation consistent with the situation of the company and only makes the incremental assumption that the other companies have the same economic depreciation rate. Making these assumptions removes objections based on the company having a different rate than assumed for others. Having the same rate for all companies is desirable because it would be difficult to determine service lives for all companies in the sample such that company-specific rates could be calculated. If one rate is going to be used for all companies, PEG believes it is best to base it on the subject of the benchmarking.

3.13 In the workpapers provided by PEG for TFP calculations, the decay rates for transmission plant and general plant are static hard-coded inputs. Please provide the approach PEG used to calculate the decay rates from the parameters outlined in the reference above.

Réponse :

Please see the following table. The calculations separate transmission plant in service into structures and equipment. Structures were assigned a declining balance parameter of 0.91 while equipment was assigned a parameter of 1.65. These values are consistent with those used by the Bureau of Economic Analysis when calculating capital stocks for the US economy. For each type of transmission asset, a decay rate was calculated. The decay rate used was a weighted average of the asset-specific decay rates. The types of assets chosen for this excluded Telecom and *Logiciels* and licenses. For *lignes*, PEG separated the lines from the poles and towers such that the former could be treated as equipment and the latter as structures. The decay rate for general plant was calculated as 1.65 divided by 18 years.

Decay Rate Calculations

Transmission Asset	Average Service Life	Percentage of Plant	HQT split	Weights	Declining Balance Parameter	Decay Rate
Telecom	21.00	4.7%				
Batiments	35.00	1.2%		1.28%	0.91	2.6%
Logiciels and licences	10.00	1.3%				
Autres actifs	12.00	1.5%		1.60%	1.65	13.8%
lignes	73.00	32.6%				
Lines	65.32		42.0%	14.57%	1.65	2.5%
Poles / Towers	75.11		58.0%	20.11%	0.91	1.2%
postes	35.00	58.7%		62.45%	1.65	4.7%
Total		100.0%		100.00%		3.81%

4. Administrative & General costs (A&G)

Reference: PEG Report p. 69: "In addition to costs of transmission plant ownership, we included a sensible share of the costs of general plant ownership… CNE that we considered comprised applicable transmission CNE and a sensible share of applicable administrative and general CNE."

Reference: PEG Report p. 69 footnote 89: "We apportioned to transmission cost a share of each American utility's general costs equal to the share of included transmission *CNE* in its net *CNE*. Since general costs are tied to the management of labor, in calculating net *CNE* we excluded some *CNE* that are large relative to their labor cost component. Examples of these excluded expenses include those for energy, transmission by others, and uncollectible bills."

Demande(s)

4.1 With respect to reference 89, please identify all categories of such expenses that were excluded and the reason why they were excluded.

Réponse :

PEG excluded from their general cost allocator expenses for fossil steam generation fuel, nuclear fuel, other power generation fuel, purchased power, other power generation other expenses, franchise fees, pensions and benefits, total regional market expenses, uncollectible bills, and transmission by others. Each of the foregoing items involves a relatively small amount of labor and administrative overhead relative to cost. This matters because administrative and general costs are sensitive to employment. Using generation fuels as an example, it only takes a small number of people to purchase fuels whereas it takes a lot of people to operate and maintain company-owned transmission assets. If fuel procurement was allowed to have the same dollar for dollar impact on cost allocation as transmission, the fuel procurement department would be assigned a greater proportion of company overhead than running the entire transmission system. This would not adhere to reasonable cost allocation principles.

4.2 Please recalculate the total factor productivity trends and the CNE and capital productivity trends with those expenses included in the share of general plant and administrative and general expenses.

Réponse :

Please see the table below for results of the requested alternative run. The multifactor productivity trend over the full sample period only changed by 0.03% (from -0.62% to -0.59%).

US Transmission Productivity Results: Alternative Allocator

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index: Summary	Input Quantity Index: O&M	Input Quantity Index: Transmission Capital	Input Quantity Index: Allocated General Plant	Productivity: MFP	Productivity: O&M	Productivity: Transmission Capital	Productivity: Allocated General Plant
1996	1.2%	-0.7%	-0.2%	-0.9%	1.2%	1.9%	1.5%	2.2%	0.0%
1997	0.9%	-1.5%	-2.5%	-1.2%	-4.4%	2.4%	3.4%	2.1%	5.3%
1998	2.2%	-1.1%	2.2%	-1.9%	2.1%	3.3%	0.0%	4.2%	0.1%
1999	2.8%	-2.0%	-4.1%	-1.9%	-2.3%	4.8%	6.8%	4.6%	5.1%
2000	0.4%	-0.7%	3.5%	-1.3%	10.5%	1.1%	-3.1%	1.7%	-10.1%
2001	1.8%	-1.4%	-5.3%	-0.9%	13.4%	3.2%	7.1%	2.6%	-11.6%
2002	0.7%	-1.0%	-4.4%	-0.4%	-4.3%	1.7%	5.1%	1.0%	4.9%
2003	1.4%	-0.3%	2.8%	-0.7%	1.2%	1.7%	-1.5%	2.0%	0.2%
2004	0.6%	0.2%	2.8%	-0.2%	-1.5%	0.4%	-2.2%	0.9%	2.1%
2005	2.7%	0.9%	4.2%	0.1%	-1.8%	1.9%	-1.5%	2.7%	4.5%
2006	2.3%	1.5%	4.5%	0.4%	-0.8%	0.8%	-2.2%	1.9%	3.1%
2007	0.0%	2.3%	5.1%	1.4%	0.2%	-2.3%	-5.1%	-1.3%	-0.2%
2008	0.3%	2.4%	5.3%	1.2%	1.0%	-2.1%	-5.0%	-0.9%	-0.7%
2009	-0.1%	3.1%	4.8%	2.5%	2.2%	-3.2%	-4.9%	-2.6%	-2.3%
2010	0.7%	2.7%	5.2%	2.2%	-1.4%	-2.0%	-4.5%	-1.5%	2.0%
2011	0.3%	2.7%	2.3%	2.9%	2.9%	-2.3%	-1.9%	-2.5%	-2.6%
2012	0.4%	1.9%	1.8%	2.1%	5.5%	-1.5%	-1.4%	-1.7%	-5.1%
2013	0.3%	4.4%	1.8%	4.9%	6.2%	-4.1%	-1.5%	-4.6%	-5.9%
2014	1.2%	4.4%	-1.3%	5.0%	0.4%	-3.2%	2.5%	-3.8%	0.9%
2015	0.4%	4.9%	-1.7%	5.9%	1.3%	-4.6%	2.0%	-5.5%	-0.9%
2016	0.8%	4.9%	5.8%	4.7%	9.6%	-4.1%	-5.0%	-3.9%	-8.8%
2017	0.1%	3.3%	0.1%	3.7%	2.2%	-3.2%	0.0%	-3.6%	-2.2%
2018	0.8%	2.7%	-0.2%	3.1%	3.9%	-1.8%	1.1%	-2.3%	-3.1%
2019	0.7%	3.7%	3.8%	3.4%	6.6%	-3.0%	-3.1%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**1.55%**	**1.51%**	**1.42%**	**2.25%**	**-0.59%**	**-0.55%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**3.05%**	**2.76%**	**2.90%**	**2.54%**	**-2.32%**	**-2.02%**	**-2.16%**	**-1.80%**

4.3 Please recalculate the total factor productivity trends and the CNE and capital productivity trends with the share of general plant and share of administrative and general expenses removed.

Réponse :

Please see the table below with the results of the requested alternative run. The multifactor productivity trend over the full sample period only changed by 0.05% (from -0.62% to -0.57%). This result is different from the similar sensitivity analysis done by Brattle where they found a much larger difference.

US Transmission Productivity Results: No A&G or General Plant

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index: Summary	O&M	Transmission Capital	Allocated General Plant	Productivity: MFP	O&M	Transmission Capital	Allocated General Plant
1996	1.2%	-0.6%	0.2%	-0.9%	1.2%	1.9%	1.1%	2.2%	0.0%
1997	0.9%	-1.4%	-3.0%	-1.2%	-4.4%	2.4%	3.9%	2.1%	5.3%
1998	2.2%	-1.3%	1.6%	-1.9%	2.1%	3.6%	0.6%	4.2%	0.1%
1999	2.8%	-2.1%	-4.7%	-1.9%	-2.3%	4.9%	7.5%	4.6%	5.1%
2000	0.4%	-0.7%	4.2%	-1.3%	10.5%	1.1%	-3.8%	1.7%	-10.1%
2001	1.8%	-1.2%	-3.4%	-0.9%	13.4%	3.0%	5.2%	2.6%	-11.6%
2002	0.7%	-0.9%	-5.5%	-0.4%	-4.3%	1.6%	6.2%	1.0%	4.9%
2003	1.4%	-0.3%	3.4%	-0.7%	1.2%	1.6%	-2.0%	2.0%	0.2%
2004	0.6%	0.2%	3.1%	-0.2%	-1.5%	0.4%	-2.5%	0.9%	2.1%
2005	2.7%	0.9%	4.8%	0.1%	-1.8%	1.8%	-2.0%	2.7%	4.5%
2006	2.3%	1.6%	4.9%	0.4%	-0.8%	0.8%	-2.6%	1.9%	3.1%
2007	0.0%	2.1%	4.8%	1.4%	0.2%	-2.1%	-4.7%	-1.3%	-0.2%
2008	0.3%	2.6%	6.0%	1.2%	1.0%	-2.3%	-5.7%	-0.9%	-0.7%
2009	-0.1%	2.7%	3.6%	2.5%	2.2%	-2.8%	-3.7%	-2.6%	-2.3%
2010	0.7%	2.5%	4.5%	2.2%	-1.4%	-1.8%	-3.8%	-1.5%	2.0%
2011	0.3%	2.7%	2.3%	2.9%	2.9%	-2.4%	-2.0%	-2.5%	-2.6%
2012	0.4%	1.8%	0.9%	2.1%	5.5%	-1.4%	-0.4%	-1.7%	-5.1%
2013	0.3%	4.5%	1.8%	4.9%	6.2%	-4.1%	-1.5%	-4.6%	-5.9%
2014	1.2%	4.6%	-0.5%	5.0%	0.4%	-3.3%	1.7%	-3.8%	0.9%
2015	0.4%	4.9%	-2.4%	5.9%	1.3%	-4.6%	2.8%	-5.5%	-0.9%
2016	0.8%	4.8%	5.4%	4.7%	9.6%	-4.0%	-4.6%	-3.9%	-8.8%
2017	0.1%	3.4%	0.3%	3.7%	2.2%	-3.3%	-0.2%	-3.6%	-2.2%
2018	0.8%	2.2%	-4.6%	3.1%	3.9%	-1.3%	5.5%	-2.3%	-3.1%
2019	0.7%	4.1%	7.2%	3.4%	6.6%	-3.4%	-6.5%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**1.54%**	**1.45%**	**1.42%**	**2.25%**	**-0.57%**	**-0.48%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**3.02%**	**2.58%**	**2.90%**	**2.54%**	**-2.28%**	**-1.84%**	**-2.16%**	**-1.80%**

Cost Benchmarking Study

5. Econometric Modelling

Reference: PEG Report p. 100-101: “A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms in the cost model. The estimation procedure that is best known, ordinary least squares (“OLS”), is readily available in commercial econometric software. It has good statistical properties under simple assumptions about the structure of the data and the error terms. These assumptions are often violated by real world economic data. A common problem in econometric cost research is autocorrelation of error terms. Autocorrelation, also known as serial correlation, occurs when data from one year are correlated to the data in subsequent years. This reduces the precision of parameter estimates and debases estimates of the error terms that are used in tests of the statistical significance of parameter estimates. This can complicate model development. Several econometric methods have been developed to address autocorrelation. One class of estimators, called generalized least squares, adjusts the parameters using estimates of the autocorrelation pattern and improves the accuracy of the estimated standard errors. We have in past studies frequently used a generalized least squares estimator with an AR1 process in our research. Another class of estimators, called robust standard errors estimators, improves the accuracy of the estimated standard errors but uses OLS to estimate model parameters. The choice between these approaches has been debated several times in recent Ontario Energy Board proceedings. 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."

Demande(s)

5.1 Is it PEG's opinion that their models reported in Tables 3-5 of the PEG report have included all relevant factors that affect total, CNE and capital transmission costs?

Réponse :

No. However, PEG strives to continually upgrade the business condition variables in their cost models and has over several studies gathered a good set of transmission cost drivers.

5.2 If any relevant factors are not included in the model but that likely have an impact on transmission costs—because, for example, they may be hard to capture in a variable—how does PEG's model account for these factors?

Réponse :

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

5.3 What statistical tests did PEG undertake during its study to test whether the OLS assumptions were violated by the "real world" transmission data at hand? Please provide the results of any tests conducted?

Réponse :

Please see the response to question 5.4.

Reference: PEG Report p. 28: "The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies."

Reference: PEG Report p. 31: "These results have important implications for benchmarking. For example, the results suggest that we can often improve the precision of an econometric benchmarking model by pooling data for sampled companies over multiple years rather than using only a cross-section of data for a single year."

5.4 Please discuss how PEG selected its preferred estimation procedure for its panel data and discuss any statistical tests that PEG performed during its study in assisting it in selecting its preferred estimation procedure.

Réponse :

PEG tested for autocorrelation and heteroskedasticity in the error terms and, on this basis, decided to use a robust standard errors estimation procedure. PEG found that

the cost performance quartile results were broadly similar (and quite negative) using a feasible generalized least squares estimator that controlled for autocorrelation and groupwise heteroskedasticity. They featured the OLS results in their report since the modeling procedure is more straightforward.

5.5 Please recalculate the models in Tables 3-5 using a fixed-effect panel estimator, provide updated Tables 3-5 and recalculate the benchmark results on pages 93-94 of the PEG report.

Réponse :

The table below provides a summary of the results of PEG's cost models estimated with fixed effects. PEG has provided benchmarking results using the standard "xb" linear prediction method and the "xbu" option that Brattle used with their fixed effects estimations.

Model	Prediction Method	HQT score
Total Cost	xbu	-6.53%
Total Cost	xb	239.30%
Capital Cost	xbu	-7.70%
Capital Cost	xb	240.26%
CNE	xbu	1.01%
CNE	xb	188.69%

It can be seen that the benchmarking scores are extremely sensitive to the predictor chosen. HQT does much better and has a score close to zero with the "xbu" predictor that Brattle used.

The following tables correspond to Tables 3-5 in PEG's February report. It can be seen that the t statistics on the parameter estimates are far lower using fixed effects than using ordinary least squares.

Econometric Model of Transmission Total Cost

Estimated with Fixed Effects

VARIABLE KEY

ym =	Miles of transmission line
ym2 =	ym squared
yptx =	Transmission peak
yptx2 =	yptx squared
ymyptx =	ym · yptx
mva0919pernsub0919 =	Substation capacity per number of stations
nsub0919perym =	Number of substations per miles of transmission line
load_tx =	Construction standards index
pctpoh =	Percent of transmission plant that is overhead
pctptx =	Percent of plant transmission
trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.060	0.34	0.736
ym2	-0.004	-0.03	0.977
yptx	0.180	1.98	0.054
yptx2	0.044	0.31	0.759
ymyptx	-0.098	-0.65	0.521
mva0919pernsub0919	-0.223	-1.47	0.149
nsub0919perym	-0.126	-0.86	0.396
load_tx	0.000	0.00	0.000
pctpoh	0.151	0.84	0.405
pctptx	0.526	3.63	0.001
trend	0.017	5.92	0.000
Constant	18.574	110.85	0.000

R-squared within:	0.646
R-squared between:	0.335
R-squared overall:	0.358
Sample Period	2004-2019
Number of Observations	711

Econometric Model of Capital Cost

Estimated with Fixed Effects

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
pctpoh = Percent of transmission plant that is overhead
pctptx = Percent of plant transmission
nsub0919perym = Number of substations per miles of transmission line
load_tx = Construction standards index
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.060	0.29	0.770
ym2	-0.049	-0.29	0.770
yptx	0.066	0.77	0.445
yptx2	0.044	0.28	0.779
ymyptx	0.039	0.25	0.802
mva0919pernsub0919	-0.192	-1.02	0.311
pctpoh	0.074	0.41	0.686
pctptx	0.547	2.97	0.005
nsub0919perym	-0.118	-0.67	0.504
load_tx	0.000	0.00	0.000
trend	0.015	5.89	0.000
Constant	13.656	76.59	0.000

R-squared within:	0.632
R-squared between:	0.068
R-squared overall:	0.093
Sample Period	2004-2019
Number of Observations	711

Econometric Model of Transmission CNE

Estimated with Fixed Effects

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
pctptx = Percent of plant transmission
pforgis1 = Percent forestation in service territory
rto = Binary variable indicates RTO/ISO member
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.207	1.38	0.175
ym2	0.207	0.96	0.341
yptx	0.492	2.11	0.041
yptx2	-0.040	-0.14	0.886
ymyptx	-0.409	-1.81	0.077
mva0919pernsub0919	-0.122	-1.33	0.191
pctptx	0.391	2.71	0.009
pforgis1	0.000	0.00	0.000
rto	-0.018	-0.23	0.818
trend	0.015	3.05	0.004
Constant	17.564	71.48	0.000

R-squared within:	0.350
R-squared between:	0.696
R-squared overall:	0.655
Sample Period	2004-2019
Number of Observations	711

PEG notes that a fixed effects estimator does not measure between-company variation. Several of the transmission cost driver variables in PEG's featured model have little within-company variation over the sample period, such that estimating with a fixed effects method only captures the effect of *changes* in the variable, and that effect is sensitive to data from the subset of companies with material changes. All costs associated with each company's own average levels are moved to the error term. Using the "xbu" prediction method, each company is benchmarked only on its

deviations from its own average costs and inefficiency.

Reference: PEG Report p. 75: "These variables were substation capacity (measured in MVA) per substation, substations per line mile, and the share of overhead assets in the gross value of transmission line assets."

5.6 Please explain how PEG processed the substation data for the sample of US companies. From the workpapers provided by PEG, it appears that substation data, both substation capacity and substations per mile, were obtained for 2009 and 2019, and values for intermediate years were interpolated with a straight line method using the two available 2009 and 2019 data points. Please confirm if this is correct.

Réponse :

This statement is confirmed. PEG first cleaned the data with programmatic rules, then hand-checked and corrected the values after discovering programmatic cleaning still missed some major problems.

The Form 1 substation data require extensive cleaning and PEG did not have the time or budget to complete a full time-series. Since mismeasurement bias is a problem in econometric modeling, PEG opted to obtain two accurate points and then interpolate values between them in order to capture both the level and overall growth.

6. Stretch Factor

Reference: PEG Report, p. 96: "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."

Demande(s)

6.1 Please provide the analysis conducted that supports the adders of 0.1% and 0.3%.

Réponse :

PEG first considered the prevalence of transmission formula rates amongst the sampled utilities. The performance impact of regulation was then considered with the aid of PEG's incentive power model. This model was most recently presented in a paper PEG wrote for Lawrence Berkeley National Laboratory. The incentive power model was discussed in Section 5 and Appendix B of that report. This paper can be accessed at:

https://eta-publications.lbl.gov/sites/default/files/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf .

7. O&M Data

Reference: PEG Report, p. 90: "As in the productivity study, we excluded costs of transmission by others. 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."

Demande(s)

7.1 Please provide evidence that the companies removed, in fact, reported the expenses as transmission by other expenses.

Réponse :

Please see the response to question 2.6.

7.2 Please recalculate the benchmarking analysis with companies included and present results.

Réponse :

When the companies included in the productivity work but previously excluded from the benchmarking work are included in the econometric model, HQT's cost performance score is 50.8%, which is 49th out of 52 companies and corresponds with a bottom quartile ranking. The rankings for all companies between the two models are highly statistically correlated, with a Spearman's rho of 0.9484 and a p-value of 0.0000.

7.3 Please recalculate the productivity study with the inclusion of the dispatching expenses and miscellaneous transmission expenses that PEG used in the benchmarking study.

Réponse :

The requested alternative analysis is provided below. It can be seen that the average *CNE* productivity trend of sampled utilities is much more negative over the full sample period but is less negative over the most recent fifteen years.

US Transmission Productivity Results: Using Benchmarking CNE

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index: Summary	Input Quantity Index: O&M	Input Quantity Index: Transmission Capital	Input Quantity Index: Allocated General Plant	Productivity: MFP	Productivity: O&M	Productivity: Transmission Capital	Productivity: Allocated General Plant
1996	1.2%	1.2%	0.0%	2.1%	-0.9%	1.3%	-0.9%	2.2%	0.0%
1997	0.9%	0.9%	0.0%	5.9%	-1.2%	0.9%	-5.0%	2.1%	5.3%
1998	2.2%	2.2%	2.1%	13.2%	-1.9%	0.1%	-10.9%	4.2%	0.1%
1999	2.8%	2.8%	-0.3%	5.7%	-1.9%	3.1%	-2.9%	4.6%	5.1%
2000	0.4%	0.4%	-0.5%	-0.4%	-1.3%	0.9%	0.8%	1.7%	-10.1%
2001	1.8%	1.8%	1.8%	5.7%	-0.9%	0.0%	-3.9%	2.6%	-11.6%
2002	0.7%	0.7%	-1.6%	-2.8%	-0.4%	2.3%	3.5%	1.0%	4.9%
2003	1.4%	1.4%	-0.2%	0.8%	-0.7%	1.6%	0.6%	2.0%	0.2%
2004	0.6%	0.6%	6.7%	18.2%	-0.2%	-6.1%	-17.6%	0.9%	2.1%
2005	2.7%	2.7%	5.2%	12.0%	0.1%	-2.4%	-9.3%	2.7%	4.5%
2006	2.3%	2.3%	0.1%	0.0%	0.4%	2.3%	2.4%	1.9%	3.1%
2007	0.0%	0.0%	-2.1%	-3.0%	1.4%	2.1%	3.0%	-1.3%	-0.2%
2008	0.3%	0.3%	3.2%	5.1%	1.2%	-2.9%	-4.8%	-0.9%	-0.7%
2009	-0.1%	-0.1%	0.0%	-3.0%	2.5%	-0.1%	2.9%	-2.6%	-2.3%
2010	0.7%	0.7%	3.3%	6.0%	2.2%	-2.6%	-5.3%	-1.5%	2.0%
2011	0.3%	0.3%	1.0%	-0.6%	2.9%	-0.7%	0.9%	-2.5%	-2.6%
2012	0.4%	0.4%	1.8%	1.5%	2.1%	-1.4%	-1.0%	-1.7%	-5.1%
2013	0.3%	0.3%	4.2%	2.0%	4.9%	-3.8%	-1.7%	-4.6%	-5.9%
2014	1.2%	1.2%	2.7%	-4.1%	5.0%	-1.5%	5.3%	-3.8%	0.9%
2015	0.4%	0.4%	5.8%	5.8%	5.9%	-5.4%	-5.5%	-5.5%	-0.9%
2016	0.8%	0.8%	4.4%	1.0%	4.7%	-3.6%	-0.2%	-3.9%	-8.8%
2017	0.1%	0.1%	3.4%	1.0%	3.7%	-3.3%	-0.9%	-3.6%	-2.2%
2018	0.8%	0.8%	5.5%	9.2%	3.1%	-4.6%	-8.4%	-2.3%	-3.1%
2019	0.7%	0.7%	1.0%	-5.0%	3.4%	-0.3%	5.7%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**0.96%**	**1.97%**	**3.18%**	**1.42%**	**-1.01%**	**-2.22%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**0.74%**	**2.62%**	**1.86%**	**2.90%**	**-1.88%**	**-1.13%**	**-2.16%**	**-1.80%**

7.4 Were there any companies that PEG included in the benchmarking study that were not included in the productivity study? If so, please provide the company names and the reasons why they were not included in the productivity study.

Réponse :

No.