Demande de renseignements numéro 1 du Transporteur (The Brattle Group « Brattle ») à l'Association québécoise des consommateurs industriels d'électricité et du Conseil de l'industrie forestière du Québec (« AQCIE-CIFQ ») (Pacific Economics Group Research LLC « PEG »)

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)."

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?

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

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

Company	In Brattle Model	In PEG Model	In Both
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.

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

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?

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?

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

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.

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?

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

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?

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.

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

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)."

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.

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

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).

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

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?

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

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

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?

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

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.

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"?

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

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.

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?

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."

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

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?

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?

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

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?

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?

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

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

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.

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

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.

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.

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."

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

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.

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.

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."

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?

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?

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?

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.

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.

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.

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."

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

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."

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

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

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.

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.