# PEG Responses to Enbridge Gas Inc.'s Interrogatories

## Statistical Benchmarking

**M3.EGI-2**

Reference:

Exhibit M3, page 85

Question(s):

Please confirm that at page 85 of the PEG report, PEG's recommended stretch factor of 0.45% is explicitly linked to Enbridge Gas's total cost benchmarking results, rather than its capital cost results.

**Responses:**

The following responses were provided by PEG.

This statement is confirmed. EGI's stretch factor would be 0.60% if it were linked to PEG's capital cost results.

**M3.EGI-3**

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides a partial regression output for the three econometric models it estimated at Tables 3, 4 and 5. Although PEG's work provides parameter estimates and t-statistics on the model's independent variables, it does not provide any evidence on Enbridge Gas's actual cost or predicted cost for any of three PEG models in any of the sample years. Moreover, there is no discussion of any diagnostic tests or sensitivity analyses designed to ensure that the econometric results models are robust and unbiased. Aside from the estimates presented in the aforementioned tables PEG does not present any of the standard statistics that would typically be presented for each of its models. In addition, there is no discussion of any of the standard diagnostic tests that PEG used to determine if its models are robust and satisfy the assumptions required for ordinary least squares regression analysis.

Question(s):

Please reply to the following statements, most of which ask Dr. Lowry to confirm a statement. If a statement is not confirmed, please explain in detail why the statement is incorrect.

a) To provide reliable (i.e. unbiased or consistent) statistical results, a regression model must have independent (i.e. ‘exogenous’) variables that are not correlated with the error term of the model.

b) If this condition is not satisfied, the regression model has what is known as an instrumental variable problem.

c) Instrumental variable problems can arise for a number of reasons, but in almost all cases, they reflect problems with independent variables used in regression models. For example, independent variables may be measured with error, or they may be correlated with other variables that are measured with error, or they may be correlated with other variables that are themselves correlated with the dependent (endogenous) variables.

d) Any such correlation would lead to biased or inconsistent regression results which would not, in turn, generate reasonable inferences on a utility's cost performance.

e) PEG's regression models treat all outputs, including customer numbers, as exogenous variables.

f) Treating customer numbers as an exogenous variable implies that the number of customers served by a utility is a random, independent variable beyond the control of the utility company.

g) The estimated coefficients (i.e. parameter estimates) for customer numbers and outputs are important, because they factor into the computation and prediction of economies of scale expected for a given utility.

h) Projected economies of scale will in turn factor into a utility company's predicted costs and therefore its cost performance.

i) PEG's benchmarking model approach does not capture or reflect the underlying dynamics of the Union-Enbridge Gas Distribution merger. One reason is that the PEG benchmarking models focus on how a utility's costs compare to the costs, and associated technology, of theoretical production functions. These benchmarking exercises are designed to assess what is known as static productive efficiency, or how efficient a utility is at a given point in time.

j) However, mergers can potentially create efficiencies that go beyond static efficiency gains by altering the technology itself; this is an example of what is known as "dynamic efficiency."

k) The PEG model is not designed to measure the transformative, technical change associated with dynamic efficiency, or efficiency gains that alter the production function itself, particularly over short periods of time.

l) Instead, PEG's models measure technical change as a steady, annual process that does not accelerate or decelerate at any point in time. This process applies equally to every sampled company in the utility industry (in this case, the gas distribution industry). In PEG's current model, at page Exhibit M3, page 73, Table 3, the industry's rate of technical change is typically measured by the "trend variable," which has an estimated parameter value of 0.00602, or 0.602 per cent in PEG's total cost model. PEG's model therefore assumes that costs in the gas distribution industry increase by 0.62% in each year, for reasons that cannot be explained by PEG's total cost model.

m) The sample period used to estimate PEG's econometric model includes the 2020 and 2021 years, when the world was suffering from the Covid pandemic.

  i) Does Dr. Lowry believe the Covid pandemic impacted the performance of essentially every economic sector in the U.S. and Canada in 2020-2021? Please explain.

  ii) Does Dr. Lowry's econometric model include any variables that reflect the impact of the 2020 to 2021 global pandemic on gas distributors' cost performance? If so, please identify these variables, their estimated coefficients, and tests of their statistical significance.

  iii) If Dr. Lowry's econometric model does not measure the impact of the 2020 to 2021 pandemic on Enbridge Gas's cost performance, would it be reasonable to conclude that the lack of a Covid variable is an example of omitted variable bias? If not, please explain where the impact of Covid in 2020 to 2021 is otherwise measured in the PEG model.

n) In 2022, the Covid pandemic abated somewhat, and worldwide commerce began to recover. Price inflation rose substantially in 2022, and this inflation was exacerbated by international supply chain issues.

  i) Does Dr. Lowry believe the supply chain problems in 2022 could have potentially impacted Enbridge Gas's utility operations and cost performance? Please explain.

ii) Does Dr. Lowry's model include any variables that reflect the impact of the 2022 supply chain issues on utility operations? If so, please identify these variables, their estimated coefficients, and tests of their statistical significance.

o) At page 80 of the PEG Report, PEG measures Enbridge Gas's cost performance over the 2019, 2020, 2021, and 2022 years. The period used to benchmark Enbridge Gas's cost performance therefore includes the Covid years of 2020 to 2021, and the worldwide surge of inflation and supply chain issues in 2022.

i) Does Dr. Lowry agree that the 2020 to 2022 years were especially chaotic and uncertain, compared with the preceding 50 years?

ii) If so, should tests of the statistical significance of PEG's predicted 2019-2022 costs for Enbridge Gas take explicit account of the exceptional uncertainty of the 2020 to 2022 period? Please explain in detail.

iii) In general, does PEG's econometric model take account of either the impact or uncertainty of 2020 to 2022 Covid-related events?

iv) If so, please identify precisely where the impact of Covid and supply chain issues are reflected in 1) PEG's estimated parameter values; 2) statistical tests of significance for each parameter estimate; 3) the magnitude of the "confidence intervals" around PEG's predicted costs for Enbridge Gas in 2019 to 2022, which are designed to reflect the uncertainty of the econometric model's predicted costs; and 4) statistical tests of the predicted costs for Enbridge Gas in 2019 to 2022?

p) More formally, does PEG agree that the EGD-Union Gas amalgamation has almost certainly created an instrumental variable problem? Recall that the instrumental variable problem arises whenever there is a correlation between one or more exogenous variables and the error term of the model.

q) Please confirm that, in PEG's model, a utility's measured cost efficiency is estimated within the error term of the model.

r) Please also confirm that 1): a key motivation for the Enbridge Gas-Union Gas merger was to achieve efficiency gains; and 2) Enbridge Gas expected that the merger would generate cost efficiencies. If PEG disagrees with either of these statements, please explain in detail.

s) Please confirm that if any efficiencies were achieved after the amalgamation, they would be reflected in the error term of PEG's econometric model, because that is where PEG measures efficiency gains. If not, please explain in detail.

t) Please confirm that the preceding bullet point implies that if the amalgamation led to any efficiency gains, there would be a positive correlation between the error term of PEG model (because that is where PEG measures efficiency gains) and the number of customers served, which is one of the exogenous, independent cost driver variables in PEG's econometric cost model; if not confirmed, please explain in detail.

u) In the preceding bullet point, this positive correlation between the error term in PEG's model and one or more of PEG's independent variables (i.e. customer numbers) clearly satisfies the definition of an instrumental variable problem. If not, please explain in detail.

v) Please confirm that there is accordingly a high probability that PEG's econometric model has an embedded instrumental variable problem, and it is therefore generating biased (or inconsistent) estimates of Enbridge Gas's cost efficiency over the 2019 to 2022 period.

**Responses:**

The following responses were provided by PEG.

<u>Preamble</u>

Before answering the detailed questions, PEG notes that several of the questions pertain to *general* problems with econometric research or econometric benchmarking that are not necessarily pronounced in PEG's study in this proceeding. In appraising BV's questions and our responses the reader should consider the following.

- Econometric benchmarking has been routinely and extensively used by utility and OEB staff witnesses in OEB proceedings since the 4th generation incentive ratemaking proceeding for power distributors. Dr. Kaufmann advised the OEB in that proceeding.
- The alternative to econometric benchmarking that Dr. Kaufmann advances in this proceeding is unit cost benchmarking. Since unit cost metrics provide a crude control for only one business condition that may vary between utilities, the accuracy of unit cost benchmarking depends greatly on the choice of a peer group. Dr. Kaufmann did not even consider differences in input prices and reliance on cast iron and unprotected bare steel ("CIBS") mains as criteria for peer group selection in his study.
- While it is worthwhile to point out imperfections of econometric benchmarking, the perfect should not be made the enemy of the good.

<u>Answers to Detailed Questions</u>

a) This statement is partially confirmed. EGI is not clear which specific "statistical results" are in question but PEG will address possible interpretations.

**Model Parameter Estimates:**

PEG acknowledges that, to claim the property of unbiasedness, linear regression requires a zero conditional mean between the error term and the regressors.[1] The relevant model properties in this research are those for ordinary least squares ("OLS") time series models. To claim unbiasedness, the zero conditional mean must hold for every independent variable in and across all time periods in the model. This is a very difficult requirement to meet and to prove in many real-life datasets. Fortunately, we can instead look at the property requirements for consistency. To

[1] This is to say that the error term is not correlated with any of the explanatory variables.

meet the requirements for consistency of the parameter estimates in an OLS time series model, only *contemporaneous* exogeneity is required, rather than exogeneity across all time periods.

As for the reliability of econometric results, this depends on the extent of bias. Biases may be small, or they may cancel out with other biases in the variables. Just so, a visit to the beach can end with a mild sunburn or an eventual case of melanoma. Many choose to go to the beach despite the exposure problem. Econometric benchmarking might still be more reliable than a unit cost benchmarking exercise.

**Validity of Inference Using the Model Parameters:**

Heteroskedasticity and serial correlation can compromise the accuracy of statistical tests of the significance of econometric model parameters. However, this problem can be remedied by calculating the standard errors using techniques which have been proven to be robust to heteroskedasticity and serial correlation.

b) This statement is confirmed but again the extent of the problem is another matter.

c) This statement is confirmed.

d) This statement is not confirmed. As noted in the response to parts a) and b) of this question, the extent of any net bias may not be so great as to render the benchmarking results unreasonable, especially when the alternative is unit cost benchmarking. Endogeneity is not a concern for most variables in PEG's models. The parameter estimates – which are the only estimates used in the cost predictions – are in line with theoretical expectations and casual empiricism.

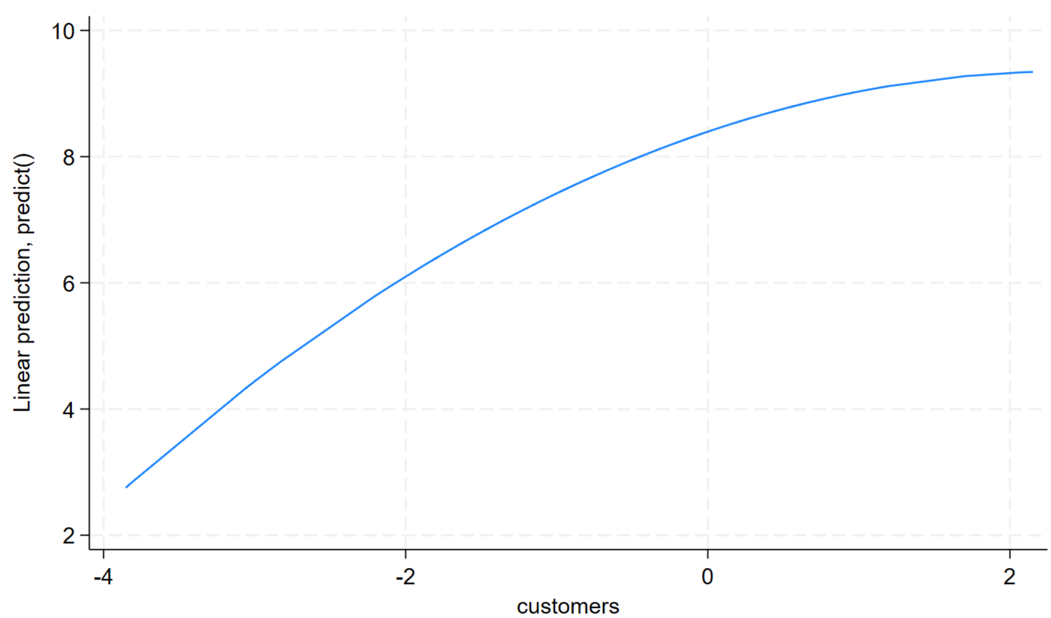
The sampled companies were involved in very few mergers of any size during the sample period. Data for EGI were not used to estimate the parameters of the three models used to benchmark EGI. The companies in the sample are not strategically dropping and acquiring customers in any sort of way which would render invalid the estimated typical relationship between a company's scale, as measured by customers, and its cost.

e) This statement is confirmed.

f) This statement is confirmed.

g) This statement is partially confirmed, but the statement is too narrow. Scale variable parameters are important in utility cost modelling because operating scale is one of the most important cost drivers. Measuring economies of scale right is part of the job of getting the cost impact of scale right. The number of customers served received the strongest statistical support by far amongst the scale variables that PEG considered.

Please also note that PEG's cost models explicitly take account of scale economies. The parameter estimates for the scale variables imply that, on average, some scale economies are expected with more customers. Please see the following graph of the continuous marginal effects implied by PEG's econometric total cost model. Expected cost increases as scale increases, but the rate of cost increase is slower at the higher end. If no scale economies were found, the line would be diagonal instead of gently curved. In BV's unit cost approach, in contrast, scale economies become one of many issues that must be considered, without the benefit of transparent empirical research, in choosing a peer group.



h) This statement is confirmed.

i) Using PEG's benchmarking methodology, the Company's cost performance improved over the four years examined, especially on the O&M side as would be expected.

j) PEG does not accept BV's claim that mergers alter the underlying production technology of utilities. It is true, however, that PEG's models reflect the *long* run rather than the *short* run impact of an increase in operating scale. PEG also notes that BV's methodology also does not address "dynamic" efficiency.

k) Please see the answers to parts i) and j) of this question.

l) This statement is confirmed.

m) This statement is confirmed. PEG's sample does include 2020 and 2021, as well as 2022.

   i) PEG acknowledges that the pandemic had an impact on the performance of many sectors of the economy. Salient examples include restaurants and brick and mortar retailers. However, it is not clear how the pandemic affected utility cost performance. Performance may actually have improved in the short term on balance if some activities were deferred without diminishing service quality. In a similar manner, the productivity of some American businesses surged as they found ways to use less commercial real estate. PEG also notes that the pandemic affected all sampled utilities and not just EGI.

   ii) The biggest impact of the pandemic was probably the acceleration of price inflation that began in 2021. PEG's sophisticated input price indexes reflect the inflation that occurred during these years. The trend variable parameters in PEG's models reflect industry cost shifts that occurred during the sample period for other reasons, including those from 2020 to 2022.

   iii) No. Prompted by this question, PEG considered the addition of a pandemic dummy variable to its models. The parameter estimate for this variable was negative and statistically significant when added to PEG's O&M Cost model, and positive but not significant when added to the Total Cost and Capital Cost models.

n)
   i) Yes. However, the supply chain issues effected all of the sampled utilities and not just EGI
   ii) Please see the answer to part m) of this question.

o) Please see the response to part m) of this question.

p) No. Instrumental variable problems are a matter of parameter estimation. According to best practices, EGI data were excluded from the parameter estimation used to develop the Company's benchmarks. EGI's cost efficiency was evaluated against estimated industry average cost performance. Any achieved cost efficiencies would reduce the distance between EGI's actual and predicted cost.

q) As in BV's unit cost benchmarking, PEG measures cost performance by calculating the ratio of EGI's cost to a cost benchmark.

r) These statements are confirmed.

s) This statement is not confirmed because EGI's data were not used to develop its benchmarking model.

t) Please see the response to part s) of this question.

u) This statement is not confirmed.

v) This statement is not confirmed.

**M3.EGI-4**

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides a partial regression output for the three econometric models it estimated at Tables 3, 4 and 5. Although PEG's work provides parameter estimates and t statics on the model's independent variables, it does not provide any evidence on Enbridge Gas's actual cost or predicted cost for any of three PEG models in any of the sample years. Moreover, there is no discussion of any diagnostic tests or sensitivity analyses designed to ensure that the econometric results models are robust and unbiased. Aside from the estimates presented in the aforementioned tables PEG does not present any of the standard statistics that would typically be presented for each of its models. In addition there is no discussion of any of the standard diagnostic tests that PEG used to determine if its models are robust and satisfy the assumptions required for ordinary least squares regression analysis.

Question(s):

a) Is Dr. Lowry aware of tests of “structural breaks” in econometric research?

b) Does Dr. Lowry believe the sudden amalgamation of Enbridge Gas Distribution and Union Gas could potentially give rise to a “structural break” in Enbridge Gas’s cost data and cost performance after 2019? Please explain why or why not in detail.

c) Does Dr. Lowry believe the unprecedented Covid-related experience of 2020 to 2022 could potentially give rise to a structural break in Enbridge Gas’s cost data and cost performance after 2019? Please explain why or why not in detail.

d) One common test of structural breaks is the Chow Test, which can be implemented straightforwardly with relatively little incremental cost.

i) Please implement Chow Tests of PEG's econometric cost model, as applied to Enbridge Gas's cost performance, to test for structural breaks in each of the following years and sets of years:

2018

2019

2020

2021

2022

The entire periods: 2018 to 2021, 2019 to 2021, 2018 to 2022, 2019 to 2022 test would therefore compare Enbridge Gas's cost performance for the 2006- 2019 and 2019 to 2022 periods.

ii) Based on the results of these Chow Tests, please explain whether the econometric research indicates that there has been a structural break in any of the requested time periods.

iii) Do the results of the Chow Tests have any implications for PEG's estimate of Enbridge Gas's total cost performance, or PEG's proposed stretch factor? Please explain in detail.

e) Please confirm, what is the "Change CIBS07 Cumulative" explanatory variable in Table 5 and how is it measured?

f) Please confirm, what is the "MEGA %MilesTx x 2020+" explanatory variable in Table 5 and how is it measured?

g) Please confirm, what is the "Electric Dummy" explanatory variable in Table 5 and how is it measured?

**Responses:**

The following responses were provided by PEG.

a) Yes. The question of whether structural breaks have occurred arises occasionally in statistical research on the utility industry.

b) EGI and Black and Veatch did not provide adequate cost data for PEG to include in the study prior to 2019. As a result, no such structural break would be included in our dataset. EGI data were, in any event, not used in the estimation of its own benchmark model parameters.

c) No. Please also see PEG's answer to Question 3, part m).

   Stresses on the supply chain, fluctuations in demand from lockdown and work-from-home policies, and business decisions regarding capital and O&M expenditure timing are all reflected in the data used to calculate the model parameter estimates. The two main avenues by which PEG accounts for this in the econometric models are as follows:

   i) PEG's input price indexes, which translate nominal costs into real costs, adjust company costs for the change in prices of labor, construction costs, and macroeconomic inflation.

   ii) The trend variable consolidates the information from each year's *industry* cost trend not explained by the model input prices and other business condition variables.

d) Please see the answers below.

   i) As mentioned in response to part b), EGI and BV did not provide the requisite data to support EGI's inclusion for the full sample period of 2008-2022 in the econometric models. Only EGI's costs from 2019-2022 are benchmarked in PEG's analysis.

   ii) Not applicable.

   iii) Not applicable.

e) Reliance on cast iron and unprotected bare steel ("CIBS") was an important driver of the cost of sampled gas utilities over PEG's sample period. We expect costs to be higher for utilities in the midst of CIBS replacement compared to those of utilities replacing less or utilities who never faced this particular cost challenge. The change in CIBS reliance matters as well as the level because replacement creates a sustained increase in capital cost even if this may to some degree be offset by lower O&M expenses. Accordingly, this variable measures the cumulative replacements since the end of 2007 in each company's CIBS as a percent of total distribution mains. For the U.S. companies, all components of this variable are sourced from the publicly available Gas Distribution Pipeline Data from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA").

PEG also considered alternative variables constructed from the PHMSA data including the share of mains made of CIBS at the start of the sample period times the trend variable. EGI had a slightly worse performance score using this alternative.

f) This variable is designed to estimate the cost effects of the U.S. Department of Transportation's mid-2020 introduction of what is known as the "Mega Rule." This rule placed stringent new requirements around the surveying, evaluating, monitoring, inspection of, and reporting on gas transmission mains.[2]

The value of this variable is 0 for all companies before 2020. Companies without transmission mains have 0 values for the whole sample period. EGI also has 0 values since the company is not subject to U.S. gas transmission safety regulation. For the sampled U.S. companies with transmission mains, the variable value used for 2020-2022 is the share of total miles of main which are onshore transmission mains.

As we would expect, this variable has a positive (as well as significant) parameter estimate in the O&M cost model. This variable was excluded from the total cost and

[2] https://www.phmsa.dot.gov/news/phmsa-final-rule-safety-gas-transmission-pipelines-repair-criteria-integrity-management-Improvements-cathodic-protection-management-of-change-and-other-related-amendments

capital cost models because its parameter estimate lacked statistical significance in each model. Its significance should improve over time in such models as problematic pipe is identified and replaced at a faster rate than before the rule.

g) The electric dummy variable takes on a value of 1 for all companies serving both electric and gas customers, and a value of 0 for companies which provide gas service only. We expect that some O&M cost efficiencies are available (in billing and customer service categories at a bare minimum) to companies serving both gas and electric customers. This variable was excluded from the total cost and capital cost models because its parameter estimate lacked statistical significance.

PEG considered as an alternative specification for this variable the percentage of gas customers in the company's total number of gas & electric customers. While the alternative measurement is intuitively appealing, a number of the combined gas and electric utilities have non-overlapping gas and electric service territories.[3] This muddles the measurement and interpretation of the expected cost savings, so PEG opted to use the binary variable.

[3] For example, National Grid provides electric service but not gas service in Buffalo but provides both services in other cities in upstate New York.

**M3.EGI-5**

Question(s):

a) Has Dr. Lowry recently provided econometric evidence that benchmarks the cost performance of energy utilities in Alberta?

b) Other than the current proceeding for Enbridge Gas, is the 2023 benchmarking evidence in Alberta the most recent, publicly available benchmarking evidence that PEG has undertaken?

c) Did the Alberta Utilities Commission (AUC) accept Dr. Lowry's benchmarking evidence presented in either 2022 or 2023?

d) In fact, doesn't the 2023 AUC Decision state that some of Dr. Lowry's benchmarking evidence is "implausible"?

e) In light of the AUC's recent, 2023 Decision, and the far greater complexity of benchmarking Enbridge Gas compared with the Alberta utility companies, how can Dr. Lowry assure the OEB that PEG's most-recently proffered evidence is not similarly "implausible"?

**Responses:**

The following responses were provided by PEG.

a) Yes.

b) No. PEG subsequently prepared power distributor cost benchmarking research and testimony for the Ontario Energy Board in case EB-2023-0195.

c) No. The AUC had not used benchmarking to set stretch factors in its prior PBR proceedings and did not accept Dr. Lowry's recommendation to set stretch factors based on PEG's benchmarking evidence in the PBR3 proceeding. One reason was its expressed concern about the general use of benchmarking to set stretch factors. The Commission stated on pages 44-45 of its recent decision that

> the translation of the benchmarking study results into a defensible stretch factor requires significant judgement and the Commission is not persuaded that such a

method would improve upon the existing approach to setting a stretch factor in a PBR plan.[4]

d) The reference to "implausible" results in the AUC decision refers specifically to the performance of ATCO Electric in 2023, where the company was found to have total costs that were 56% above the benchmark. In that context, the Commission stated the following on page 44 of the decision.

> In particular, [the distribution utilities] pointed to PEG's admission that the results for ATCO Electric bordered on the implausible… The Commission agrees that PEG's benchmarking studies in this proceeding are first generation and may not be entirely robust as demonstrated by the change in ATCO Gas's result through the course of the proceeding and the "implausible" result for ATCO Electric.

The AUC did not state that PEG's benchmarking results were generally implausible. To the contrary, the AUC stated on page 45 of its decision that

> the Commission considers that PEG's analysis, while not sufficient to rely upon in this proceeding, does provide a useful point of reference that suggests that most Alberta distribution utilities have superior performance as compared to the comparator group of U.S. distribution utilities.
>
> The Commission encourages PEG to continue to refine its methodology, and to consider presenting benchmarking results for the next PBR term, which may be used to inform any stretch factor at that time. Further, the distribution utilities are encouraged to work with PEG to ensure PEG has the necessary information prior to any such filing.

e) Dr. Lowry has a PhD in applied economics from the University of Wisconsin. He has undertaken econometric cost benchmarking research and testimony in dozens of proceedings stretching back to the 1990s. At least a dozen of these studies benchmarked gas utility costs. The substantial funding for these projects over the years has facilitated many improvements in PEG's benchmarking methods. The parameter estimates in PEG's models in this proceeding are plausible and results have usefully been provided for O&M and capital as well as total cost. Work for

[4] Alberta Utilities Commission Decision 27388-D01-2023, pp. 44-45.

diverse clients that have included legacy Enbridge Gas Distribution has bolstered PEG's reputation for objectivity and in this proceeding PEG is working for the Ontario Energy Board, a disinterested party.

The bulk of EGI's operations occur under business conditions that are within the range of experience of our sampled U.S. distributors. In contrast, ATCO Electric serves a sprawling region of low population density well to the north of Ontario's populated latitudes that contains extensive forests and muskeg. U.S. gas utility operating data have notable advantages in benchmarking (e.g., the length, composition, and age of mains). Quality data on the length and age of power distribution lines are, in contrast, not readily available for a large number of U.S. companies.

Note, finally, that PEG's benchmarking methods in this proceeding compare favorably to those used by BV and are more in keeping with those commonly used in the OEB's electric IR proceedings.

**Aggregating TFP Results**

**M3.EGI-6**

Reference:

Exhibit M3, page 82

Preamble:

PEG states: "Table 7 reports annual growth rates in the O&M, capital, and multifactor productivities of all sampled U.S. gas utilities for each year of the full sample period. Even-weighted and size-weighted averages are both presented. Examining the even-weighted averages we find that total factor productivity averaged a 1.26% annual decline. O&M productivity growth averaged a slight 0.01% annual decline while capital productivity growth averaged a more substantial 2.17% annual decline. As for the cost-weighted averages, total factor productivity averaged a 1.54% annual decline."

Question(s):

One important issue for estimating total factor productivity trends for multiple companies is how individual company results should be aggregated into a single TFP measure.

There are two general approaches to this issue: 1) compute a simple average of each sampled utility's TFP growth (even-weighted); or 2) weight the data of different companies (size-weighted or cost-weighted).

a) Please confirm that for Dr. Lowry's full-sample TFP results, industry TFP declined by 1.26% per annum when sampled utilities were even-weighted, and industry TFP declined by 1.54% per annum when sampled utilities were cost-weighted.

b) Please confirm that Dr. Kaufmann's full-sample, cost-weighted TFP analysis estimates that industry declined by –1.52% per annum.

c) Please confirm that when Dr. Kaufmann and Dr. Lowry both estimate TFP trends using the full industry sample and cost-weighted averages, there is only a difference of two basis points between their estimated TFP trends (i.e. -1.54% for Dr. Lowry, and –1.52% for Dr. Kaufmann).

d) Does Dr. Lowry believe that if two TFP studies estimate industry TFP trends that differ by only two basis points, it is reasonable to characterize these TFP estimates as "robust." Please explain why or why not.

e) Does Dr. Lowry generally prefer to compute TFP using even-weighted rather than cost-weighted /size-weighted data?

f) Please explain the benefits Dr. Lowry believes are associated with the even-weighted approach.

g) If Dr. Lowry believes that both approaches are potentially reasonable, please explain what criteria he uses for deciding whether to compute even-weighted rather than size-weighted TFP trends.

h) Suppose, Dr. Lowry was retained to compute the TFP trend for the Ontario gas distribution industry, comprised of Enbridge Gas with over 3.9 million customers; and EPCOR Ontario, which serves approximately 8000 customers. Would Dr. Lowry use even-weighted or size-weighted methods?

i) Has Dr. Lowry ever recommended that "econometric research typically assigns the same weight to every utility regardless of size"?

j) Other than Dr. Lowry's own TFP studies, please provide a list of every North American TFP study he is aware of where the research "assigned the same weight to every utility regardless of size." In each instance, please identify the year and Docket number for the study, and please cite the page numbers and/or workpapers which confirm that TFP trends were estimated using simple averages rather size-weighted data.

k) In particular, please indicate whether TFP studies submitted in the seven Massachusetts dockets listed below used weighted data or simple averages when computing TFP trends.

  - 2023, D.T.E. 03-40
  - 2005, D.T.E. 05-27

- 2017, D.P.U. 17-05
- 2018, D.P.U. 18-150
- 2019, D.P.U. 19-120
- 2020, D.P.U. 20-120
- 2022, D.P.U.,22-22

l) Please also confirm that Massachusetts Department of Public Utilities has reviewed and approved more TFP studies for utility incentive regulation plans than any other North American regulator.

**Responses:**

The following responses were provided by PEG.

a) This statement is confirmed. PEG concludes that there is a modest difference between the size-weighted and even-weighted averages.

b) This statement is confirmed.

c) This statement is confirmed.

d) Two studies with similar results may not by themselves support a claim of robustness. However, when combined with other recent results such as those from PEG's study for the OEB's Amalco IR proceeding, PEG acknowledges that the TFP trend of the U.S. gas utility industry as a whole has tended to be materially negative in the last fifteen years.

e) No. When a national productivity peer group is appropriate, Dr. Lowry has tended to use even-weighted averages for utilities of small to average size and size-weighted averages for larger utilities such as EGI. This approach produces a more customized productivity growth target to the extent that the realization of incremental scale economies tends to vary with utility size, as it does in power distribution. Dr. Lowry has also tended to use even-weighted averages when regional or custom peer groups are warranted out of fear that results could otherwise be dominated by the experience of a few large utilities.

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

g) The criteria employed are 1) the size of the subject utility, 2) evidence that incremental scale economies vary considerably by company size, and 3) the risk that size-weighted trends will be unduly sensitive to results for a few large utilities.

h) In this hypothetical case it would be desirable to use a size-weighted average since the goal of the study is to measure the TFP trend of the Ontario industry. The mandate in this proceeding is instead to produce an appropriate TFP growth target for EGI.

i) This is not a recommendation but rather a statement of fact.

j) PEG reviewed a number of productivity trend studies not prepared by PEG personnel and found that all used size-weighted averages when calculating full-sample productivity trends. In Ontario's fourth-generation IRM proceeding, this approach was one reason that Toronto Hydro and Hydro One were excluded from the industry averages.

k) Utility-sponsored TFP studies in D.P.U. 17-05, D.P.U. 18-150, D.P.U. 19-120, D.P.U. 20-120, and D.P.U. 22-22 all used size weights.[5] Dr. Lowry submitted TFP studies in D.P.U. 18-150 and D.P.U. 19-120 which were based on even weights. PEG was unable to determine whether Dr. Kaufmann relied on even weights or size weights in his testimony for Boston Gas in 2003. .

l) Not confirmed. PEG understands that the Massachusetts Department of Public Utilities ("MA DPU") and a predecessor agency have together reviewed TFP studies in 1 telecom and 10 energy utility proceedings (e.g., Boston Gas 3 times, NSTAR Gas once, Eversource Energy twice, NSTAR Electric once, Fitchburg Gas & Electric

[5] PEG notes that Bay State Gas in D.T.E. 05-27 relied on the same TFP study as approved in the prior Boston Gas proceeding (D.T.E. 03-40).

once, and National Grid twice).[6] However, the Ontario Energy Board has reviewed TFP studies in at least 4 power distributor proceedings (e.g., 1GIRM, 3GIRM, 4GIRM, and the recent Toronto Hydro proceeding), 4 gas distributor proceedings (Union Gas – 2000, Generic Gas proceeding in 2007, the Amalco proceeding, and this proceeding), 1 hydro-electric generation proceeding, and 3 power transmitter proceedings [Hydro One Sault Ste. Marie, Hydro One Networks (2019), and Hydro One Networks (2022)]. PEG also notes that the funding available for productivity counterstudies in Massachusetts is well below that available in Ontario, and this affects the quality of information available to the regulator. However, MA DPU has *approved* more IR plans with X factors based on TFP study results than the Ontario Energy Board has, as the OEB has to date declined to approve negative productivity factors.

[6] PEG is not including in its count for the MA DPU those TFP studies which were fully vetted in 1 proceeding and then used as the basis for subsequent IR proposals. Similarly, the count for the Ontario Energy Board excludes IR proceedings in which TFP results from previous proceedings were used as the basis for IR proposals.

**<u>"Custom Enbridge Gas Peer Group" and Measurement of TFP Trends</u>**

**M3.EGI-7**

<u>Reference</u>:

Exhibit M3, page 83

<u>Preamble</u>:

At page 83, Table 7 of the PEG Report shows that PEG estimated a –1.54% TFP growth trend for the U.S. gas distribution industry over the 2004-2022 period. This –1.54% TFP trend results when PEG computes TFP for the entire gas distribution industry and weights the TFP results of individual companies. These are both standard, rigorous, and long-established practices for estimating TFP trends for energy utilities over the last 30 years.

It is also noteworthy that Dr. Lowry's industry TFP results are nearly identical to Dr. Kaufmann's results. Using a somewhat different methodology, Dr. Kaufmann estimated a -1.52% TFP trend for the gas distribution industry over the 2006-2022 period. Together, the Lowry and Kaufmann studies imply that a gas distribution TFP estimate a few basis points below –1.50% is robust and amply supported by alternative productivity methods.

However, Dr. Lowry is not recommending that his industry TFP results be applied in the IRM for Enbridge Gas. Dr. Lowry explains this decision by stating:

> National average TFP trends from the United States do not provide a suitable basis for establishing an X factor for EGI. The principal reasons for this are as follows.
>
> - The productivity factor should reflect to the extent practicable the business conditions that EGI will face going forward.
> - Casual empiricism supported by our econometric cost research suggests that some of the biggest drivers of declines in US gas utility productivity in the last 15 years are not relevant to EGI's situation going forward. In particular, EGI has few cast iron and bare steel mains and is not likely to face the costly transmission safety

mandates that many gas transmission providers in the States contended with during the sample period. EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant.

A more reasonable productivity growth peer group for Enbridge would accordingly be U.S. utilities that started the sample period with little CIBS, did not own much transmission capacity, and had a fairly normal rate of customer growth on average.

Question(s):

a) What is Dr. Lowry's view about the impact of the Phase 1 Decision and the subsequent Bill 165 on the business and operating environment for Enbridge Gas over the 2025 to 2028 term as compared to the business and operating environment during the deferred Rebasing term.

b) In order for Enbridge Gas to maximize its incentives for the 2025 to 2028 term, shouldn't the incentive regulation mechanism be consistent with the "competitive market paradigm", in which incentive regulation plans are designed to emulate the outcomes and incentives of competitive markets? Please explain.

c) Doesn't the application of the competitive paradigm require that parameters of incentive regulation plans, including the productivity factor, be calibrated using industry-wide measures of TFP growth? Please explain why or why not.

d) Given the current environment, wouldn't Dr. Lowry agree that a productivity factor based on industry-wide TFP trends will better reflect to the extent practicable the business conditions that Enbridge Gas will face going forward? Please explain why or why not.

e) What specific evidence does Dr. Lowry have to support the view that Enbridge Gas "is not likely to face the costly transmission safety mandates that many gas transmission providers in the States contended with during the sample period"?

   i) Do Canadian regulators and policymakers have less interest in pipeline safety than U.S. policymakers and regulators? If not, why is it reasonable to expect that there would be substantial differences in safety standards between U.S. and Canadian gas utilities over the long run?

ii) Is it more reasonable to expect Enbridge Gas's safety-related expenses to become more rather than less similar to those of U.S. utilities going forward? Please explain.

f) At page 83, Dr. Lowry's primary reason not to use industry-wide TFP estimates is provided, PEG states: "Casual empiricism supported by our econometric cost research suggests that some of the biggest drivers of declines in US gas utility productivity in the last 15 years are not relevant to EGI's situation going forward. EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant."

i) Beyond "casual empiricism" does Dr. Lowry have any specific data or evidence to support his hypothesis that "EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant." If so, please provide these data.

ii) Is Dr. Lowry aware that Enbridge Gas effectively replaced all its cast iron assets by 2012?

iii) Please see Table 1 below which, examines the average annual growth in Enbridge Gas's capital stock, for 1998 through 2012, or the years in which Enbridge Gas was replacing cast iron, and the 2012-2022 period for the 10 years after aged cast iron had been replaced. These growth rates have been computed for Enbridge Gas's distribution operations as well as its overall operations.

Table 1

| Periods | Distribution Only | All Operations |
|---|---|---|
| 1998 to 2012 | 3.61% per annum | 3.45% per annum |
| 2012 to 2022 | 3.68% per annum | 3.70% per annum |

It can be seen that during the 1998 to 2012 period when Enbridge Gas was replacing cast iron and bare steel assets, Enbridge Gas's capital grew at an average annual rate of 3.61% for Enbridge Gas's distribution (and allocated general capital) services, and 3.45% per annum for all of Enbridge Gas's operations. However, in the 2012 to 2022 period, Enbridge Gas's capital stock grew by 3.68% per annum for distribution services and 3.70% per annum for all services. Capital stock therefore grew more rapidly in the second period.

Dr. Lowry has hypothesized that Enbridge Gas's capital expenditures would decline after programs to replace cast iron and bare steel assets had been completed.

Does this empirical evidence lead Dr. Lowry to amend his prediction that Enbridge Gas's cost growth is likely to slow due to the Company's "early replacement" of cast iron and bare steel assets? Relatedly, does this analysis reduce Dr. Lowry's emphasis on cast iron and bare steel replacement as the most critical cost driver variable? If not, please provide additional evidence that supports Dr. Lowry's hypothesis and emphasis on the replacement of cast iron and bare steel assets.

g) How does Dr. Lowry define "fairly normal rate of customer growth"?

**Responses:**

The following responses were provided by PEG.

a) PEG understands that this question is referring to the impacts of the OEB's Phase 1 decision changing the revenue horizon for small volume customer connections from 40 years to zero and the Ontario government's response to this decision, which was to require the OEB to set a new revenue horizon for gas distribution. In this context, revenue horizon is the number of years of presumed revenue. This horizon is used to determine the economic feasibility of new distribution system connections and capacity expansions as well as the amount customers must pay in contributions in aid of construction to be connected to the system.

While this issue is unresolved, PEG expects that the growth in EGI's number of customers and miles of main will be slower in the next five years than it was in the past fifteen years. In Exhibit I.10.1-Staff-60 part e), EGI provided a forecast of 0.95% average customer growth for the 2025-2029 period.

b) PEG does not believe that slavish adherence to the competitive market paradigm is appropriate when setting productivity factors for utility rate plans. When the productivity growth drivers facing utilities in the full national sample differ markedly from those facing the subject utility, the competitive market paradigm tends to encourage windfall gains and losses for subject utilities. Choosing a regional or custom productivity peer group on the basis of similar external productivity growth drivers reduces the risk of windfall gains and losses and will not weaken the productivity growth incentives of the subject utility. These are reasons why the OEB chose an Ontario peer group to inform the choice of a productivity factor for the fourth-generation IRM for provincial power distributors. Dr. Kaufmann advised OEB staff in that proceeding.

c) The answer to this question depends on the definition of the competitive market paradigm. If the definition is to simulate the *incentives* found in competitive markets to the extent practicable, then it is sufficient to use results for a regional or custom peer group in which utilities face similar productivity growth drivers to those that the subject utility is likely to face going forward.

d) No. In choosing a productivity growth peer group for EGI, it is necessary to identify the main recent historical productivity growth drivers of sampled utilities, gauge their relative importance, and then see how these may differ between alternative candidate peer groups and those of EGI going forward. Econometric cost research is useful for this. We have used this method to determine that customer growth and reliance on cast iron and unprotected bare steel mains were major productivity growth drivers during the sample period. EGI has solved its cast iron and unprotected bare steel problem whereas many U.S. utilities still had sizable amounts of CIBS during the sample period and U.S. utilities operated under different gas distribution and pipeline safety regulations than Enbridge. We are additionally concerned that gas transmission safety policy is different in the U.S. than in Canada.

This analysis points to a productivity growth peer group with low reliance on CIBS mains, no gas transmission, and customer growth similar to that which EGI forecasts going forward.

e)

i) PEG does not believe that Canadian policymakers and safety regulators are less interested in pipeline safety than their U.S. counterparts. However, PEG understands that Canadian safety regulators tend to be less prescriptive in their regulations than their U.S. counterparts. Under Canadian regulations, the EGI legacy companies chose to replace their CIBS mains early.

PEG also understands that U.S. pipeline safety regulations tend to be reactive to recent U.S. transmission pipeline safety problems such as the San Bruno explosion in suburban San Francisco that occurred in 2010. The U.S. Pipeline and Hazardous Materials Safety Administration has issued several rules on gas transmission pipeline safety regulations that have and will continue to increase gas transmission costs (e.g., the Mega rule). A broader array of pipe lines are objects of proactive rules. PEG understands that no package of rules analogous to the Mega rules exist in Canadian Standards Association ("CSA") rulemaking Z662, which establishes essential requirements and minimum standards for the design, construction, operation, maintenance, and abandonment of Canada's oil and gas pipeline systems. Moreover, Z662 is not likely to be revised for several years.

ii) PEG does not have an opinion on this.

f)

i) Empirical research isn't required to support the contention that once a plant addition has been made its depreciation tends to slow cost growth. The larger the plant addition, the larger the slowdown. All else equal, the end of a particular capex program should also slow cost growth. The contention is not that cost growth is slower than before, just that it is slowed. However, there have been instances in the United States when a combination of large generation plant additions and slow inflation, brisk volume growth, and/or other favorable business conditions have permitted vertically integrated electric utilities to stay out of rate cases for many years. Examples include Duke Energy in the Carolinas and Florida Power and Light.

ii) Yes, and since this happened more than a decade ago, PEG acknowledges that the effect on the Company's cost growth has diminished. The point is that any effect on EGI's productivity growth going forward is positive, however small.

iii) PEG does not understand the meaning of capital stock in this question or the source of the table provided.

g) In the 15 years of PEG's featured sample period, the average annual customer growth of the full sample averaged 0.76%.

**M3.EGI-8**

Reference:

Exhibit M3, page 84

Preamble:

Dr. Lowry has proposed to estimate TFP trends using a small sample of eleven utilities that appear to have little in common with Enbridge Gas. Throughout his 30-year career as an incentive regulation consultant, Dr. Lowry's work has mainly focused on estimating industry TFP trends using large samples of utility companies.

At page 84 of the PEG report, Dr. Lowry justifies this choice, saying that:

> A reasonable productivity growth peer group for Enbridge would accordingly be U.S. utilities that started the sample period with little CIBS (*i.e*. cast iron and bare steel), did not own much transmission capacity, and had a fairly normal rate of customer growth on average. We have developed a peer group consisting of all sampled utilities that, specifically,
>
> - had distribution plant exceeding 80% of total gross plant value
> - relied on CIBS mains for less than 5% of their distribution line length in 2007.
>
> We then removed the two utilities with the most rapid customer growth during the sample period to better reflect EGI's customer growth prospects going forward.
>
> Eleven utilities satisfied these criteria. Their customer growth averaged 0.95% annually during the sample period.

Question(s):

a) Did Dr. Lowry provide TFP evidence in the MAADs regulatory proceeding that approved Enbridge Gas's current IRM?

b) In that MAADs proceeding, was Dr. Lowry's proposed TFP and benchmarking evidence developed using a large sample of U.S. gas distribution utilities?

c) Please identify how many sample utility companies Dr. Lowry used to estimate industry TFP trends in in the MAADs proceeding, which approved Enbridge Gas's current IRM.

d) Have Enbridge Gas's business conditions changed substantially since the MAADs proceeding that approved the X factor in Enbridge Gas's current IRM? If so, please describe in detail these substantial changes in Enbridge Gas's business conditions.

e) In particular was the issue of cast iron and bare steel replacement, which plays a dominant role in Dr. Lowry's current recommendations, markedly different in 2019 than it is in 2024? Please explain in detail.

f) In the MAADs proceeding, did Dr. Lowry link the selection of utility companies used to estimate TFP trends to those firms' relative cast iron and bare steel assets in any previous year? Please describe in detail.

g) In any previous TFP study, has Dr. Lowry selected companies to be used for TFP or benchmarking research based on their shares of cast iron and bare steel assets in a previous year? If so, please identify all such TFP estimation projects, by year and docket number, as well as the specific criteria Dr. Lowry used to select sample companies based on previous cast iron and bare steel asset levels.

h) If Dr. Lowry has not previously selected sample companies for TFP research based on their past levels of cast iron and bare steel assets, please explain in detail what developments, or new information, led Dr. Lowry to select companies for his current, proposed TFP research based on their previous shares of cast iron and bare steel assets.

i) Please confirm that in 2023, Dr. Lowry provided TFP evidence in Alberta that was developed using a sample of 90 utility companies.

j) Why is it appropriate for Dr. Lowry to use 90 companies to estimate TFP trends in 2023, and to reduce the number of sampled companies by 88% when estimating TFP trends one year later? Please explain in detail.

k) Has Dr. Lowry previously recommended custom, or customized, TFP results in Alberta?

l) Please identify the year and docket number for every TFP and/or benchmarking study where Dr. Lowry has recommended custom or customized TFP targets in Alberta.

m) Has the Alberta Utilities Commission (AUC) ever accepted Dr. Lowry's proposed, customized TFP evidence? Please explain in detail.

**Responses:**

The following responses were provided by PEG.

a) Yes.

b) Yes. Dr. Lowry proposed to base the productivity factor in the Amalco proceeding on the TFP trend of the full national sample. There was no benchmarking study.

   PEG did not consider the issue of a custom peer group for Amalco in this proceeding. One reason is that the (0.23%) decline in the national TFP trend was much less negative than it is today. The sample period for PEG's Amalco study was 1999-2016. In 2010, PHMSA's final rule establishing integrity management requirements for gas distribution pipelines became effective and the San Bruno pipeline explosion occurred.

   Another reason that a custom peer group wasn't considered was that a great deal of time was expended in that proceeding challenging the use by Amalco witness Jeff Makholm of National Economic Research Associates ("NERA") of a particular one hoss shay approach to the calculation of power distributor capital cost. NERA's approach produced implausibly negative productivity growth results in the later years of the sample period. This problem prompted Dr. Makholm to declare a zero productivity growth rate to be reasonable for the Amalco without much empirical substantiation.[7] In the subsequent Alberta "PBR3" proceeding Dr. Makholm's

[7] It is notable in this regard that EGI's new witness Dr. Kaufmann used NERA's capital cost specification in a few studies where he collaborated with Christensen Associates but not in his recent independent productivity and benchmarking evidence.

productivity growth results for recent years were even more implausibly negative.

c) PEG's full sample contained 58 U.S. gas utilities in the MAADs proceeding.

d) No. The biggest change in the business conditions facing the amalgamated gas utility has been a slowdown in output growth. The need for a custom peer group arises instead from events in the United States that rendered the industry productivity trend less relevant.

e) Yes. Please see the response to question b) for an explanation.

f) No. Please see the responses to part b) of this question for explanation.

g) As set forth in Table N.M3-EGI-8g, Dr. Lowry provided custom productivity peer groups for Enbridge and Union in a 2007 OEB proceeding. He has recommended regional peer groups to set productivity factors in at least 10 proceedings. When the application was to a gas utility (e.g., Boston Gas), the need for a regional peer group was due in part to special CIBS challenges that vary across U.S. utilities.

h) PEG had more time in this proceeding to address the CIBS issue, which looms as a much more important issue than it did during the Amalco proceeding since the advance of several years removed several of the years before distribution integrity management plans and transmission line safety became more important and replaced them with several years in which they were more important. New econometric modelling results were available to guide peer group selection.

i) This statement is confirmed. However, the mentioned study addressed the productivity trends of *power* distributors, not those of *gas* distributors. Dr. Lowry was a witness in all three of Alberta's generic PBR proceedings and touted the relevance of regional and custom peer groups in all three proceedings. In the first generation PBR proceeding, he presented an econometric MFP projection and productivity results for a western peer group. In the second generation PBR proceeding, Dr. Lowry proposed a rapid growth power distributor peer group and presented results for a western peer group. In the third generation PBR proceeding, Dr. Lowry provided a Western peer group as an alternative to a national peer group.

Table N.M3-EGI-8g

## Use of Regional and Custom Productivity Peer Groups in IR Proceedings

| Report Date | Client | National Productivity Results Reported? | Regional or Custom Peer Productivity Results Reported? | If So, What Sample Size of Regional/Custom Peer Group? | Regional or Custom Peer Group Advocated? |
|---|---|---|---|---|---|
| **Mark Newton Lowry** | | | | | |
| 1994 | Niagara Mohawk | Yes | Northeast | 28 | Yes |
| 1994 | Central Maine Power | Yes | Northeast | 18 | Yes |
| 1996 | Boston Gas | Yes | Northeast | 19 | Yes |
| 1997 | BC Gas | Yes | Northwest | 5 | Yes |
| 1997 | Atlanta Gas Light | No | Southeast | 6 | Yes |
| 2005 | NSTAR Gas and Electric | No | Northeast | 25 | Yes |
| 2007 | Central Maine Power | No | Northeast | 14 | Yes |
| 2007 | Ontario Energy Board | Yes | Custom | Enbridge (10 for Geometric Decay, 10 for COS)<br>Union (10 for Geometric Decay, 11 for COS) | Yes |
| 2008 | Central Vermont Public Service | Yes | Northeast | 13 | Yes |
| 2011 | Consumers' Coalition of Alberta | Yes | Western | 7 (Western Peer Group) | No |
| 2013 | Central Maine Power | No | Northeast | 30 | Yes |
| 2013 | Fitchburg Gas and Electric | No | Northeast | 23 | Yes |
| 2016 | Consumers' Coalition of Alberta | Yes | Custom | 21 (Rapid Growth Peer Group) | Yes |
| | | | Western | 10 (Western Peer Group) | No (preferred custom peer group instead) |
| 2020 | Office of the Attorney General in Massachusetts | Yes | Northeast | 27 (Northeast) | Yes (if no capex tracker) |
| 2023 | Consumers' Coalition of Alberta | Yes | Western | 11 (Western Peer Group) | No |
| **Larry Kaufmann** | | | | | |
| 2003 | Boston Gas | No | Northeast | 16 | Yes |
| 2010 | Boston Gas | No | Northeast | 22 | Yes |
| 2011 | Union Gas & Enbridge | No | Custom peer groups: gas distributors under IR and those identified via econometrics/clustering analyses | 5 | No (productivity trends were used for comparison of performance) |
| 2013 | OEB (4th GIRM) | No | Ontario | 73 | Yes |
| 2024 | FortisBC | Yes | Small Companies - electric study only | 20 | No |
| **Christensen Associates** | | | | | |
| 2020 | Boston Gas | Yes | Northeast | 29 (Northeast) | Yes |

j) The AUC had rejected proposals for custom productivity peer groups in its prior generic IR proceedings and PEG did not have the time or budget to provide convincing empirical support of the merit of a regional peer group in the PBR3 proceeding. In the instant proceeding, in contrast, the need for a custom peer group is manifest and the OEB already uses a regional peer group to inform the choice of a productivity factor for power distributors.

k) Yes. Please see the response to part i) of this question for details.

l) Docket 566 (2011-2012), Docket 20414 (2016), Docket 27388 (2023)

m) No. However, as Dr. Kaufmann would know well, Ontario and Massachusetts have used regional peer groups to inform the choice of productivity factors.

**M3.EGI-9**

Reference:

Exhibit M3, page 41

Preamble:

Table 1 of the PEG report identifies over 100 examples of what the Table calls "North American Energy Utility Productivity Evidence."

Question(s):

a) How many of the examples in Exhibit M3, Table 1 provide evidence of industry TFP trends? Please identify each study in Exhibit M3, Table 1, that measures TFP trends for a utility industry.

b) How many of the utility industry TFP studies identified in Exhibit M3, Table 1 were computed using 11 or fewer sampled utilities? Please identify each industry TFP study calculated using 11 or fewer companies. Please also include the year and Docket Number where these studies were provided.

c) Please confirm that six of the 11 utilities Dr. Lowry has proposed to use to estimate industry TFP trends are based in the midwest United States.

d) Please confirm that four of these six midwest companies are based in Wisconsin, one is based in Illinois, and one is based in Indiana.

e) In light of the diversity within the U.S. gas distribution industry, does Dr. Lowry believe it is appropriate for more than one-third of the companies used to estimate industry TFP trends to be based in a single state (*i.e.,* Wisconsin). Please explain.

f) Please confirm that one of the other Midwest utilities, North Shore Gas, serves approximately 150,000 customers in a largely affluent, suburban territory north of Chicago.

g) Please confirm that four of the remaining five peers serve territories largely in the Northwest United States.

h) Please confirm that much of the Northwest U.S. is growing briskly and therefore adding gas distribution customers at a rate far above the U.S. national average.

i) Please confirm that the remaining peer, New York State Electric and Gas, serves a territory in New York that largely borders Pennsylvania and is far from the densely populated Eastern seaboard.

j) Please confirm that, on average, Dr. Lowry's eleven proposed peers served 411,596 customers in 2022.

k) Please confirm that Enbridge Gas's customer base in 2022 exceeded 3.9 million customers and was therefore nearly 10 times greater than the average customer numbers served in Dr. Lowry's Custom IR Peer Group.

l) Please confirm that the population of the largest city in the territories of the 11 selected peers averaged 355,909.

m) Please confirm that, in 2022, the population of the city of Toronto was 3,025,647, while the estimated population of the Toronto metropolitan area was 6,471,850.

n) Please confirm that, over the 2013 to 2022 period, average customer growth for Dr. Lowry's 11 company peer group was equal to 1.44%.

o) Please confirm that the 1.44% grow rate in Dr. Lowry's sample is more than double the 0.68% customer growth trend for the U.S. gas distribution industry computed in Dr. Kaufmann's TFP study.

p) Please also confirm that Enbridge Gas's recent growth in customer numbers is becoming more similar to that of the overall U.S. industry.

q) Please confirm that customer growth rates have a direct impact on estimated TFP growth in both Dr. Lowry's and Dr. Kaufmann's TFP studies, because in both cases gas distribution output is measured by the growth in customer numbers.

r) Since Dr. Lowry's peer group has an average rate of customer growth of 1.44% per annum, and Dr. Kaufmann's research shows a 0.68% average annual increase in customer numbers, please confirm that the difference in customer growth between these studies is equal to 0.76%.

s) Please confirm that, all else equal, a differential of 0.76% in customer growth will lead directly to a 0.76% or 76 basis point increase in estimated TFP growth.

t) Therefore, all else equal, please confirm that restricting the TFP sample to the 11 companies recommended by Dr. Lowry will increase the industry's estimated TFP trend by 76 basis points, compared with the full-sample TFP trend.

u) Dr. Lowry's econometric model for capital cost performance includes an "urban core" measure as an independent variable. When implementing this model, were any of Dr. Lowry's 11 selected peers designated as serving an "urban core"? Please explain.

v) Did Dr. Lowry's capital cost econometric model designate Enbridge Gas as having an urban core?

w) If none of the selected peers serve an urban core, while Enbridge Gas does serve an urban core, please explain how the 11 selected peers are representative of Enbridge Gas's business conditions? In doing so, please consider the importance of the urban core issue in utility cost benchmarking in Ontario.

**Responses:**

The following responses were provided by PEG.

a) It would be onerous for PEG to review all of the studies in this table but PEG acknowledges that most of the studies provided productivity trends for full national samples. However, some provided additional results for a regional sample and/or custom peer group and some provided only results for a regional peer group. One reason regional peer groups have been common is that IR based on price and productivity indexing has been particularly popular in the northeastern U.S., where utility productivity trends are often slower than U.S. norms. In several cases, the author(s) of productivity studies have recommended a regional or custom peer group as the basis for the productivity growth factor. Commissions have approved productivity factors based on regional peer groups in Ontario and Massachusetts.

Dr. Kaufmann has proposed basing productivity factors on the trend in a regional peer group on multiple occasions. Most notably, the choice of a productivity factor in the fourth generation IRM for Ontario power distributors was informed by a study of Ontario power distributor productivity trends that he supervised.

b) PEG cannot easily answer this question but the table provided in response to EGI-8(g) shows that regional and custom peer groups often have less than twenty companies. PEG finds BV's preoccupation with the number of companies in PEG's custom productivity growth peer group surprising inasmuch as there are only seven companies in BV's custom unit cost peer group.

c) This statement is confirmed. The American Midwest and West are home to most of the gas utilities in PEG's full sample that didn't own many cast iron and unprotected bare steel distribution mains or gas transmission lines during the sample period. By way of explanation, many sampled gas utilities in the Northeast U.S. have CIBS problems and PEG's sample, like Dr. Kaufmann's, doesn't have many gas utilities from sunbelt states east of California.

d) The statement is confirmed. Wisconsin is one of the younger states in the Midwest (it only became a state in 1848) and its gas utilities have been less reliant on CIBS mains or company-owned transmission. Customer growth has been modest and this makes the average customer growth of the custom peer group more like EGI's.

e) Yes. PEG's method for selecting TFP growth peers considered criteria suggested by the econometric work to have a demonstrable impact on cost growth. We found that customer growth, CIBS main reliance, and transmission line ownership were salient productivity growth drivers during the sample period. We selected as peers U.S. utilities that as a group had productivity growth drivers during the sample period that matched the future conditions forecasted by EGI. It is acceptable for the peer group resulting from this process to have several peers from one state.

f) This statement is confirmed. EGI serves similar suburban areas of Toronto and Ottawa and the slow customer growth of North Shore helps to bring down the custom peer group average to a rate that is similar to that which EGI forecasts going forward.

g) This statement is confirmed. Please see our response to part c) of this question for an explanation.

h) This statement is confirmed. Many gas utilities in the Pacific Northwest did grow rapidly during the sample period and this accelerated their productivity growth. However, the average customer growth of PEG's custom peer group is similar to the 0.95% annual growth that EGI forecasts.

i) NYSEG's service territory in southern New York includes several industrial communities like those found west of Toronto in EGI's territory. NYSEG's sluggish customer growth helps make the average for the custom peer group match that expected for EGI going forward.

j) PEG cannot confirm that exact number. However, smaller operating scale doesn't matter in selecting a productivity growth peer group unless larger utilities are expected to realize materially different incremental economies from growth in scale.

k) The statement is not confirmed. PEG relied on a value of 3,833,112 for EGI's number of customers in 2022. This is the same value BV used in its calculations. Please see the response to part j) of this question for additional context.

l) PEG cannot confirm that exact number. Please see the response to part j) of this question for context.

m) The statement is confirmed. Please see the response to part j) of this question for context.

n) The statement is not confirmed. PEG calculates 1.08% customer growth for the peer group for the 2013-2022 period (e.g., this calculation averages the growth in customers for each company using 2012 customer numbers as the base). EGI's customer growth trend in the 2013-2022 period averaged 1.31% annually. Moreover, the sample period for PEG's productivity study is the fifteen years from *2008* to 2022. During these years, the customer growth of PEG's custom peer group averaged 0.95%, which is the same rate as EGI forecasts for the 2025-2029 period.

o) Please see the response to part n) of this question.

p) This statement is confirmed.

q) Confirmation depends on the meaning of "direct." Customer growth increases the TFP growth of a gas utility to the extent that there is excess capacity in the short run and an opportunity for incremental scale economies in the long run.

r) Dr. Lowry confirms that 1.44% less 0.68% equals 0.76%. The statement has limited relevance for the reasons noted above. In particular, please see the response to part n of this question.

s) This statement is *not* confirmed inasmuch as it presumes that incremental customer growth can be achieved with zero incremental input growth. If there are no cost consequences to output growth it would be reasonable to have higher TFP growth expectations for EGI. Please see the response to part n) of this question for additional context.

t) The statement is not confirmed. Please see the response to parts n) and s) of this question for context.

u) Yes. Puget Sound Energy's service territory includes an urban core. The Seattle-Tacoma-Bellevue metropolitan area has a population exceeding 4 million.

v) Yes.

w) Serving an urban core has been demonstrated to affect utility cost levels and has therefore been included in the cost level benchmarking model. However, it has not been demonstrated to be a productivity *growth* driver.

**M3.EGI-10**

Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides its regression outputs in the referenced tables but does not provide any information of how these models were estimated.

Questions:

a) For the models set out in the referenced tables please confirm that each of the models was estimated using ordinary least squares. If not confirmed please explain the estimation procedure used for each model.

b) For the models set out in the referenced tables please provide the functional form for each model. For example, are the models presented estimated using a linear specification, log-linear specification, log-log specification or some other specification?

c) The number of observations provided in each of the referenced tables equals 859 observations with a sample period of 2008 to 2022.

    i) Were the models presented in the referenced tables estimated using cross-sectional time-series/panel data?

    ii) Were the models set out in the referenced tables estimated using data for all 57 companies provided at Exhibit M3, page 64, Table 2? If not, please provide a table for each model which shows each company included in the data used to estimate each of the models.

    iii) Please explain how the number of observations for each of the referenced models (859) is greater than the number of years included in each respective model the sample times the number of companies (57 companies times 15 years = 855 observations).

**Responses:**

The following responses were provided by PEG.

a) The models were estimated using time-series panel data. PEG used ordinary least squares to estimate cost model parameters and used the Driscoll-Kraay standard error estimation technique to correct the standard error estimates for serial correlation, heteroskedasticity, and spatial correlation.[8] We chose the fixed-b method for determining the relevant critical values so that the Driscoll-Kraay standard errors are valid for small-N, small-T samples.[9]

b) Real cost, the dependent variable in all three models, is in log form. Four of the thirteen unique independent variables across the three models are not logged because they contain values of 0. The values for the variables "%CIBS 4 Years Prior" and "Change CIBS07 Cumulative" are 0 for any company which either never had cast iron and unprotected bare steel distribution mains or which eliminated 100% of those mains before 2007. The "Urban" and "Electric Dummy" variables are binary, so they also can't be logged. Finally, the trend variable is not logged so that it represents average industry technical change per year. The other variables are logged.

   All independent variables except for the trend variable are meanscaled. Thus, each coefficient can be interpreted as the incremental percentage effect on real cost at the sample mean value of the variable.

c) This is confirmed.

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[8] Hoechle, Daniel. "Robust standard errors for panel regressions with cross-sectional dependence." *The Stata Journal* 7.3 (2007): 281-312. A free copy of the paper can be found here: https://journals.sagepub.com/doi/pdf/10.1177/1536867X0700700301

[9] "Heteroskedasticity, Autocorrelation, and Spatial Correlation Robust Inference in Linear Panel Models with Fixed-Effects", *Journal of Econometrics, Journal of Econometrics*, 166(2), 303-319, 2012. A free working paper version is available at author Tim Vogelsang's Michigan State University website: https://sites.google.com/view/tim-vogelsang-msu/research?authuser=0

i) The models were estimated using time-series/panel data.

ii) Yes, all 57 U.S. companies in Table 2 were included for all 15 years from 2008-2022.

iii) The 4 additional observations beyond the balanced panel of 855 are for EGI for the four years from 2019 to 2022.

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Reference:

Exhibit M3, page 73, Table 3

Exhibit M3, page 75, Table 4

Exhibit M3, page 77, Table 5

Preamble:

PEG provides its regression outputs in the referenced tables but does not provide any of the diagnostic tests typically applied to the results of an econometric model.

Questions:

a) For each of the models set out in the referenced tables please provide the full statistical results of any diagnostic tests used to determine if the models exhibit the following:

   i) Serial correlation

   ii) Heteroskedasticity

   iii) Autoregressive conditional heteroskedasticity (ARCH)

b) If none of these diagnostic tests were completed please explain why not?

c) Each of the three models presented include the following independent variables: Number of Customers, Number of Customers Squared and Customer Growth since 2008. The latter two independent variables are a function of the former which suggests they would be highly correlated with each other. Did PEG conduct any diagnostic tests to determine if these variables are correlated? If yes, please provide those results. Please explain why multicollinearity amongst these variables is not an issue for each of the referenced models.

**Responses:**

The following response provided by PEG addresses all three questions.

It would be surprising if these panel data did *not* exhibit these three characteristics. The dataset consists of multiple observations for the same companies for many years. It would not make sense for the individual observations of cost, number of customers, and so on for the same company to behave as though they were completely uncorrelated.

Instead of running tests for self-evident characteristics of these data, PEG implemented the standard error correction procedure described in the answer to question 10, part a). This procedure adjusts for all of the characteristics listed in part a) above and additionally for spatial correlation.

PEG does not routinely conduct correlation tests on variables which are by definition a function of one another. The “Customers” and “Customers Squared” variables capture the typical effect of customers on cost and are both needed to accurately measure the industry average effect of total scale on company costs.

The “Customer Growth since 2008” variable, calculated as the ratio of the customer number in 2022 to the customer number in 2008, is intended to capture the typical additional capital costs associated with adding new customers to the system, the reduced O&M in a modern distribution system, and the typical reduced cost savings on maintenance and cost efficiency in adding new customers to the already-existing billing and customer service structure. The only issue of concern is whether the proxy variable adds enough unique information to the model to be statistically significant. The Growth variable exhibits this characteristic of a successful proxy as it adds information to the model in a plausible manner.