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March 3, 2014

Via Email
Original via Mail

Commercial Energy Consumers
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Attention: Mr. Christopher P. Weafer

Canadian Office and Professional Employees
Union Local 378
c/o Jim Quail, Barrister & Solicitor
2nd Floor, 4595 Canada Way
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Attention: Mr. Jim Quail

Dear Messrs. Weafer and Quail:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively the Companies)

Applications for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Applications)

Rebuttal Evidence of Dr. Edwin Overcast, Black & Veatch to the Evidence of:

- **Dr. Mark Lowry, on behalf of the Commercial Energy Consumers Association of British Columbia (CEC), and**
- **Ms. Barbara Alexander, on behalf of the Canadian Office and Professional Employee's Union, Local 378 (COPE)**

The Companies respectfully submit the attached Rebuttal Evidence of Dr. Edwin Overcast, Black & Veatch to the Evidence of Dr. Mark Lowry, on behalf of CEC, and the Evidence of Ms. Barbara Alexander, on behalf of COPE, in accordance with British Columbia Utilities Commission (BCUC or the Commission) Orders G-9-14 and G-10-14 establishing the Regulatory Timetable for the above noted proceedings.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC. and
FORTISBC INC.

Original signed by: Diane Roy

For: Diane Roy and Dennis Swanson

Attachments

cc (email only): Registered Parties

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC or the Companies)
Applications for Approval of
Multi-Year Performance Based Ratemaking Plans for
2014 through 2018

Rebuttal Testimony of
Dr. H. Edwin Overcast, Black & Veatch

to Evidence of
Barbara Alexander (COPE) and
Dr. Mark Lowry (CEC)

March 3, 2014

Introduction

Q1. Please state your name and business affiliation.

A1. H. Edwin Overcast, Director, Management Consulting Division of Black & Veatch (B&V).

Q2. Have you previously provided evidence in this proceeding on behalf of FEI and FBC?

A2. Yes. I am the principal author of the B&V reports filed as part of the initial evidence related to the PBR proposals including the TFP studies and the report on other Canadian PBR plans. I am also the author of the responses to a number of interrogatories of the parties to this proceeding that are attributed to B&V.

Q3. Have you provided a summary of your educational and professional qualifications related to this evidence?

A3. Yes. My CV has been included in the initial filing in Appendix D-3.

Q4. Please provide an outline of the subjects you will address in this rebuttal testimony.

A4. This rebuttal testimony will address issues related to the proposed PBR that arise out of the evidence of Dr. Lowry of the Pacific Economics Group (PEG) filed on behalf of CEC. These issues include, but are not limited to, the calculation of the X-Factor, the use of a building block approach, and the appropriate measure of inflation. I will also discuss certain issues relative to the testimony of Ms. Alexander related to the treatment of SQIs.

Q5. How is your testimony organized?

A5. In addition to this Introduction section, the testimony is organized into nine sections as follows: Section One- Basic Economics of I-X, Section Two- Basic Assumptions for TFP Analysis, Section Three- PEG Data Errors in TFP Study, Section Four- Issues Related to the Impact of Capital on the Calculation of the X-Factor, Section Five- The Issues Related to the Impact of PEG Implicit and Explicit Assumptions on the Calculation of the X-Factor, Section Six- Measures of Inflation, Section Seven- PEG Errors of Omission, Section Eight- PEG Criticisms of the B&V TFP Calculations and Section Nine- Economic Issues Associated with the Service Quality Index (SQIs).

Q6. Please summarize the issues where PEG has erred in its development of the different components of the I-X formula and the reason for rejecting the PEG results.

A6. The following table lists the errors discussed in detail elsewhere and provides a brief reason for rejecting the PEG analysis:

Summary of Issues

Issue	PEG Position	B&V Response
Output Measure	Net New Customers	Does not measure the outputs produced unless a capacity measure is included as well.
Input Measure	Direct labor costs divided by a labor price index equals labor input	The same labor price index is not valid for use on each utility because the labor input mix differs with different technologies and with different operating factors.
Input Measure	Real capital investment equals nominal capital investment divided by a regional Handy Whitman Index	The Handy Whitman Index cannot properly reflect the actual capital input mix for each utility because every utility's mix differs based on technology and different operating factors.
Input Measure	Capital Price Index uses average capital structure for industry	There is a range of capital structures for utilities.
Input Measure	Capital Price Index uses average debt cost for industry	Debt is an embedded cost and differs from utility to utility.
Input Measure	Capital Price Index uses average equity cost for industry	Equity costs differ from utility to utility because of different risks such as business risk and regulatory risk.
Input Measure	Capital Price is an average cost	Efficient decisions are based on the marginal cost of capital that differs for each utility.
Input Measure	Assets no longer useful after depreciation life	Evidence shows that assets are used and useful beyond their depreciation life.
Input Measure	Uses a single set of depreciation rates for all utilities	Depreciation differs based on environmental conditions and asset mix.
Input Measure	Measures service life of assets based on accounting depreciation	Service life is not equal to depreciation life.
Input and Output	Implicitly Assumes Utilities use the same technology set	Sunk costs, lumpy capital additions and long run cost minimization assure that no two utilities have the same technology set.
Errors in output measure	Number of customers incorrect for some companies in sample	Correction impacts TFP estimates.
Errors in input measure	Includes costs that are not costs for ratemaking for some companies in sample	Included costs that were not eligible for rate recovery.
X-Factor Adjustments	Fails to adjust X-Factor to match macroeconomic I-Factor	Does not make adjustments even PEG acknowledges should be made resulting in essentially a zero X-Factor.
X-Factor Result	Positive X-Factor	Inconsistent with infrastructure replacement as PEG acknowledges in other testimony.

Q7. Please summarize the practical relevance of all of the debate over the appropriate I – X formula.

A7. I – X is not just an academic debate. Under regulation this formula has real consequences for the success or failure of a PBR Plan. If the results of the application of a formula provide no opportunity for the utility to earn its allowed return there is no reasonable basis for adoption of the formula. Based on the forecasts for revenue requirements initially filed by both FEI and FBC, it is possible to estimate the cumulative change in O&M revenue requirements and in capital spending under the PEG proposed formula contained in response to BCUC IR 1.22.1 to the forecast costs. The PEG formula produces a cumulative shortfall in O&M revenues and capital expenditures relative to forecasts of between $112 million and $129 million for FEI depending on the low or high construction cost case and $34 million for FBC. These values are up to four and a half times as large as the required savings under the Companies PBR Plan. In other words, the PEG formula would require that the Companies achieve over four times the efficiency savings than those already proposed by the Company. Essentially, the PEG proposal cannot provide a reasonable opportunity to earn their return. Given the history of PBR Plans and the significant savings already captured by both FEI and FBC, there is no reason to believe that this magnitude of savings has any chance of being achieved and therefore the PEG recommendation results in a confiscatory revenue trajectory and fails the important test that the results of the Plan must be just and reasonable. This will be explained in more detail in Section Six of my testimony.

Q8. Please provide your general comments related to PEG's testimony.

A8. Having previously testified on a panel with Dr. Lowry, I know that he has prepared a TFP analysis of the X-Factor using the academic paradigm that he has used for a number of years and is very comfortable with his model. It is fair to say that he is an expert in the academic model realm and he has applied the basic model used by PEG since at least the 1990s in this case.

In the context of the academic approach he has followed his selected theoretical process in a sound manner for the most part. He has not, however, reflected the most up-to-date theoretical developments in his analysis as I will discuss below in Section Four. The issue with Dr. Lowry's estimation of TFP is simply that the academic model is not reasonable as applied by PEG (or other academics) for purposes of evaluating the economics of the utility industry because the underlying assumptions do not accurately reflect the characteristics of the utility industry.

<u>Section One- Basic Economics of I-X</u>

Q9. Have you reviewed the testimony and IR responses of Dr. Lowry of PEG filed on behalf of CEC?

A9. Yes.

Q10. Both you and Dr. Lowry provide opinions regarding the I-X component of the PBR plan. How would you characterize, at a high level, the fundamental differences between your approaches?

A10. The two approaches are fundamentally different because Dr. Lowry relies on the following elements:

1. Bases the TFP method on an older version of the academic paradigm;
2. Relies on a single factor (adjusted for regional differences) to convert historic book costs from nominal to real dollars;
3. Relies on a single price index (adjusted for regional differences) to calculate the physical quantity of inputs; and
4. Uses only a single measure of net customers to measure output.

I note that even with the more recent developments of the academic model that Dr. Lowry has excluded, the academic paradigm cannot be used in a regulatory proceeding because the assumptions required to calculate the inputs are not valid because they rely on the ability to use a single factor (adjusted for regional differences) to convert historic book costs from nominal dollars to real dollars (the deflator) and then relying on a single price index (adjusted only for regional differences in the case of labor) to calculate a measure of inputs (the input quantity). Simply, if either the deflator or the input price is incorrect the results of the PEG method are meaningless and both are incorrect in the PEG analysis. By choosing to use only one measure of output - net customer growth, Dr. Lowry has an incomplete specification of the output measure and ignores the substantial differences in customer mix that create different output mixes and input mixes to serve customers in different utilities.

In contrast, the B&V approach is much simpler. It does not require the creation of an index for all companies because it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs. The B&V approach assumes that each company is unique and that it is possible to estimate TFP for that unique mix of inputs and outputs by using only each utility as a separate entity and then find a measure of central tendency to estimate the industry TFP. The B&V approach has the advantage that it is completely transparent, reflects the reality of the utility industries and adheres to the fundamental economic principle of measuring the change in output not accounted for by the change in input. This residual includes scale economies, technical efficiency, productive efficiency and output mix effects. The B&V method produces a logical result whereas the PEG method does not produce a logical result. Finally, in applying the PEG results in the case of FEI or FBC the level of expenditures is inconsistent with the regulatory principle of providing the utility with a reasonable opportunity to earn the allowed return as demonstrated by applying the PEG results to each Company.

Q11. For context, please explain the purpose of the I-X formula used by PEG as it relates to the proposed PBR Plan.

A11. Under any PBR Plan, initial revenue requirements are determined for the Fortis utilities based on the cost of service. During what is sometimes referred to as the regulatory control period (the period during which the revenue requirements are adjusted based on an adjustment formula) the I-X result is used to match the revenue requirement to the cost of service. Dr. Lowry calls the adjustment factor an attrition relief mechanism (ARM). The cost of service for Fortis is given by the basic revenue requirements equation as follows:

$$RR = O + M + D + T + RB*ROR$$

Where RR is the revenue requirement, O is operating expense, M is maintenance expense, D is depreciation expense, T is taxes of all kinds, RB is rate base that includes net plant and other rate base items and ROR is rate of return based on the weighted cost of debt and equity where equity cost is the economic cost of capital in the market. The fundamental idea of this cost of service is to provide the utility an opportunity to earn the market return of and on the investment that is both used and useful and prudently incurred.

Both components of the I-X formula (or ARM in the PEG report) must work together to assure that Fortis has that reasonable opportunity to earn the market return in each year of the regulatory control period while maintaining reasonable service quality over the period. The I Factor should measure the impact of inflation on both FEI and FBC as inflation impacts the cost of various inputs to production. It is important to choose the I-Factor in a manner that reflects the types of inputs used by both utilities. The X- Factor is designed to take into account the various factors that impact the way costs change over time.

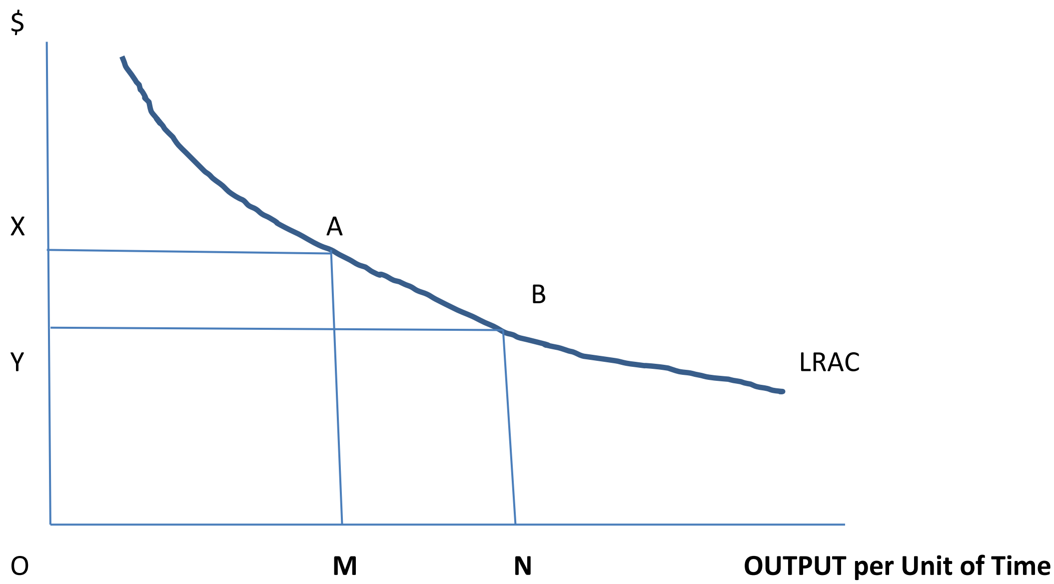
Dr. Lowry discusses four factors that are included in the measurement of TFP (MFP) as technical efficiency, economies of scale, X-inefficiency and business condition impacts. Others have discussed the sources of productivity gains as technological change, technical efficiency, allocative efficiency, scale efficiency and output mix effect. Underground wiring is one example of the output mix effect among others. It is useful to understand these concepts in some detail in order to understand the TFP concept.

Q12. Please explain the various sources on efficiency as they impact revenue requirements.

A12. Dr. Lowry relies on various equations to explain these concepts. The best way to talk about these issues is to use a simplified set of assumptions to illustrate the concepts under a comparative statics approach. Figure 1 below illustrates the revenue requirement determination under a regulatory model and the data we observe for estimating TFP.

Figure 1

Determination of Revenue Requirements



In this figure, the rectangle OXAM represents the revenue requirement. It is based on the current technology as employed by the utility underlying the long run average cost curve for the production of M outputs. If we assume no change in the technology set or input prices between the production of output of M and N then the new revenue requirement would be given by OYBN and the change in productivity could be represented by the scale economy effect only because of no change in the technology set and no change in either technical or allocative efficiency and no inflation. M and N would be the measure of output for a TFP study and the components of the cost of service can be used to measure inputs indirectly as the cost of the inputs divided by the price of the inputs or we could use the actual physical inputs as a direct measure. This recognizes that productivity is about the change in outputs and the change in inputs. The measurement of TFP would produce a positive value so that I-X would produce the new revenue requirements for the growing output of this firm.

Q13. Is this stylized static model representative of real world economics?

A13. No. In the real world we do not know the shape of the long run average cost curve nor do we know how the curve changes with inflation or technology because changes are dynamic and we only observe prices and quantities of multiple outputs provided by the same firm. We do know conceptually the direction that the curve moves as changes occur. Obviously inflation moves the curve up while technology moves the curve down. We do not know the actual production function that represents the way inputs are combined to produce outputs. In fact, the estimate of TFP has its origin in a residual that measures the portion of the change in output not explained by the changes in input. This has led to the observation by some economists that the measure of TFP is "a measure of our ignorance" simply because it is a residual.[1]

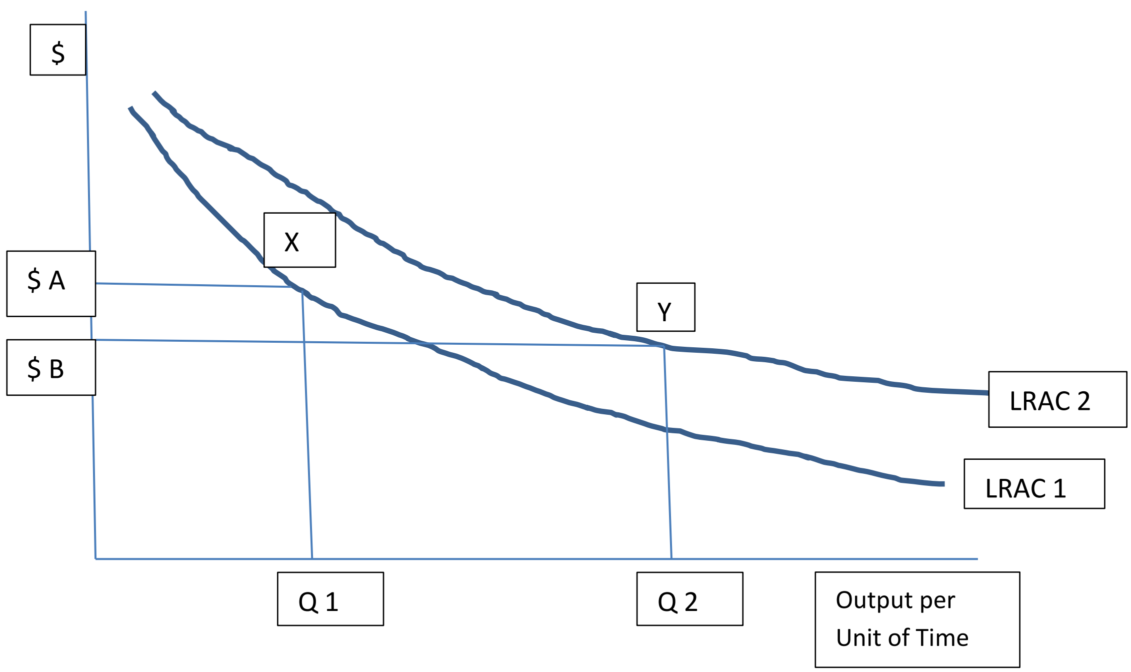
The residual nature of the measurement provides insight on efficiency, scale and other factors of interest but as is the case in any residual measurement it also includes unwanted effects such as measurement error, model misspecification and omitted variables. As a result we need to use a large sample to essentially estimate the parameters of TFP and even then there is much less precision in the estimate than would be required to support an evidentiary measure for the I-X formula as demonstrated by the different results and recommendations from PEG. This is not an unusual condition for regulators as they often deal with a range of results in estimating the equity cost of capital.

Q14. Please illustrate how various factors change the long-run cost curve under this simple model.

A14. By this simple model, we can illustrate a change in inflation by shifting the cost curve upward for inflation. The change in the technology set shifts the cost curve downward either in a parallel fashion for neutral technical change and with a different slope for non-neutral technical change.

Figure 2

A Two Period Comparison of Cost Curves



All of the costs in the LRAC are in nominal terms since costs and outputs are defined for a specific period of time. It is also convenient to assume that the measurement of TFP uses only

[1] "Total Factor Productivity A Short Biography", Charles R. Hulten, from New Developments in Productivity Analysis, University of Chicago Press, January 2001

the physical quantities of inputs. The measurement of TFP compares the change in output from Q 1 and the measure of inputs at output Q 1 to the output at Q 2 and the measure of inputs at Q 2. In both cases, the outputs are physical quantities. If output grows faster than inputs TFP is positive and if inputs grow faster than outputs TFP is negative as would be the case with infrastructure replacement. This is the residual concept noted above since if the change in output is greater than the change explained by the inputs it must be explained by other factors.

TFP methodology is designed in some cases to explain those other factors individually as illustrated by the PEG report values for partial factor productivity (PFP) for O&M and capital. In other cases it measures the sum of all effects and under certain assumptions may do so although not with the precision granted to the TFP estimates simply because there are other factors that impact the TFP measure that are not accounted for in the analysis under any model. It is important to note that the basic concept of index methodology assumes that output and input points represent the available technology set for each period of the analysis although these points may not be optimal for the particular technology set. This is an implicit assumption in order for the index to be meaningful. It is easy to see that if we were to assume that curves LRAC 1 and LRAC 2 were different utilities in the same period, nothing could be concluded from the TFP index value because the change would not be relevant for either utility 1 or utility 2 because they have vastly different production technology sets in the same period as occurs in the real world of utility economics. This brings us to the issue of calculating the TFP of the industry as a measure of central tendency of productivity. The theory requires certain basic assumptions that may be explicit or more likely implicit to support the analysis.

Section Two- Basic Assumptions for TFP Analysis

Q15. Are there basic assumptions that are required to estimate TFP in the PEG methodology?

A15. Yes. In particular, PEG makes basic assumptions about the gas and electric distribution industry that do not reflect the character or operation of the industries as will be discussed below in more detail. Studies and the results are only as good as the assumptions about how the firms make decisions and operate. Incorrect assumptions produce incorrect, unreliable results and the result of the PEG approach has no economic meaning in the context of the way utilities actually operate. Absent behavior equivalent to the explicit and implicit assumptions the PEG results do not meet the evidentiary test that is the basis for a regulatory decision. In our stylized comparative statics model we illustrate the upward shift in the long-run cost curve as the impact of changing factor prices and changing technology which may also change the way that inputs are used.

The implicit assumption underlying the shifting long-run cost curves is that the change in technology can be implemented immediately across the entire utility because it is the whole curve that shifts upward. This is a competitive market assumption (the basis for the PEG model) where there are no sunk costs. In gas and electric utility industries it is only possible to implement the new technology at the margin. Each utility implements the new technology when that technology is efficient for the utility given their unique input prices based on local market conditions and the required output mix. It is for this reason that we observe different rates of technical progress for different utilities. PEG assumes that capital is fungible (a new technology can completely replace the old technology as soon as it becomes available) over time (it is not), that all utilities adopt and implement new technology as it becomes available (they do not and it is not even efficient to do so), and that all firms are technically efficient (they are not because of sunk costs, lumpy capital additions and regulatory constraints). These points are discussed below in Section Four.

The key point to understand in this discussion is that it is not possible to develop a meaningful index to evaluate TFP using the methodology of the PEG report or indeed any of the various academic models used by consultants in various Canadian and U.S. filings to date. A simple example will illustrate this point. The most common index in use today is the Consumer Price Index (CPI). The CPI is calculated for a consistent set of products called a market basket and measures the change in prices for that same basket over time. It is based on data collected from samples about the prices of various standardized goods that are sold to consumers based on the amount of the item, a dozen eggs or a pound of choice sirloin steak and items are weighted by the share of the household budget spent on each item.

To measure the index it is important to use the same market basket of goods over time or the index would not be meaningful as a point of reference for consumer prices[2]. The logic for developing a TFP index using an indirect measure of inputs requires the total cost divided by a price index that is based on the same type of logic. The use of the same technology in each period by each utility is the only way a price index divided into costs produces a consistent measure of inputs and the adoption of new technology in subsequent periods is implicitly assumed so that the values are comparable and can be aggregated to produce the industry TFP under the index methodology. PEG uses costs divided by a price index to derive physical inputs. The derivation must reflect the underlying technology since it is the technology and the relative prices of inputs that drive the optimum input mix and the quantity of the inputs required to produce the outputs.

It is also critical for the PEG TFP estimate to assume that the same input mix is used to produce the outputs in order for the indirect measure of inputs to be valid. If each utility has a different mix of inputs, essentially a different basket of inputs, the standardized measure of the input price index will not reflect the actual price of the inputs used to produce the total cost for the utility. It is worth noting here that this is not just my opinion but is also explicitly stated in the Forward section of the Handy Whitman Index as follows:

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[2] There is substantial debate over the appropriate CPI measure and indeed any number of these indexes. Should the index be fixed based or chained, how should substitution bias be treated and other issues that question various methodological issues?

> In rate cases, when a more exact determination of value is desired, however, the Index must be used carefully. Average prices and cost trends are used to develop the Index and any direct application of cost trends without checking with local experience may not be accepted without controversy.
>
> State of the art changes often affect costs independently of inflation. New regulatory and environmental requirements, changes in work rules, and improved design standards, for instance, increase construction costs even though the prices of wages, materials and equipment may be static. Trended construction costs will not reflect such changes.[3]

The input mix factor for either labor or capital differs from one utility to the next and thus cost differences reflect those different mixes of inputs. PEG measures the input index as the cost of the input (labor for example) divided by an index of labor costs that differs only with the regional difference in labor costs and not with the actual mix of labor inputs for specific technology employed by the utility. That is, PEG uses a standardized market basket of labor to determine the price it divides into the utility costs to indirectly measure the quantity of inputs. PEG does not know if that basket is applicable to each utility in the sample simply because each utility will in fact use a different input mix based on far more variables than a price of labor index or a price of capital determined without reference to even the most basic factors that cause capital cost to differ. The resulting indirect measure of inputs is wrong unless the price index is based on the bundle of inputs used by the utility not by some average market basket of inputs. The following simple example demonstrates this point.

Assume that we have two utilities A and B with different labor costs such that the cost for A is greater than the cost for B. If both use the same technology and purchase the same market basket of labor than it is easy to see that ACost/PI where PI is the price index equals the quantity of the input labor used by utility A. It is also easy to see that ACost/PI is greater than BCost/PI and the input measures are comparable values for developing an index. If the two utilities have different production functions and purchase a different basket of inputs then PI differs for both A and B. To calculate the input measure using duality principles (the concept that the cost function can be used to measure inputs of production rather than requiring the physical units of inputs to production) would require that ACost be divided by a price index for A and similarly for B, BCost would need to be divided by its own unique price index otherwise we would not have an accurate measure of the input quantities. Specifically, with different technologies and different input mixes the physical inputs for utility A may be more than, equal to or even less than those for utility B despite utility A having higher overall labor costs. It all depends on the relationship between the price index for each utility. A higher index for utility A as compared to B may result in fewer inputs for utility A even with higher costs for labor. The PEG analysis cannot reflect this reality because the fundamental assumption related to the price index is not supported by actual operating conditions.

[3] Handy Whitman Index, Whitman, Requardt and Associates, November 2013, p. iv

It is not sufficient to include only a general price measure as discussed above because both the quality and quantity of labor or the labor mix determines the actual labor costs. This means that a valid measure of TFP analysis must also include a measure of both the quantity and quality of the inputs. The PEG method to be sound must assume that each utility uses the same market basket of standardized labor components and if the utilities do not the input measure cannot be the basis for an index of labor inputs. The assumption that each utility uses the same market basket of standardized labor components is false as can be seen from the discussion below.

If gas main maintenance requires a significant amount of hand labor to uncover the main (as would be the case in an urban setting) the mix of labor inputs would differ from the case where the main can be uncovered by a piece of capital equipment with a skilled operator. The PEG price index that is critical to PEG's determination of the input quantity for labor cannot distinguish between labor types that have different costs and hence different weightings in the proper price index used to calculate the inputs. Under the PEG method for estimating labor inputs, two utilities in the same region with identical labor costs would have identical labor inputs under the PEG assumptions.

There is so little difference in the PEG labor cost index over the sample period that one is led to believe that the labor inputs are all assuming the same basic technologies and production processes for all utilities as well. In reality, two utilities could have the same labor costs and different levels of labor input because they use a different mix of labor and capital in different parts of the business. Theory is unambiguous that both the quality and the quantity of labor matters. This is a logical conclusion since in a competitive labor market the payment to labor matches the marginal productivity of the labor input. In our example above the skilled operator of a backhoe earns more per hour that the man with a shovel. For example, an urban utility may have more service personnel because of the need to excavate main by hand but reads meters remotely or has out sourced meter reading while another utility may read meters but use capital equipment to excavate mains. The net result is a different number of employees with different skill levels and different prices that cannot be reflected in the PEG analysis. Thus a measure of the quantity of labor under the PEG method for comparing the two utilities has no relevance.

Q16. You have provided examples of different types of labor costs related to the skills required for distribution maintenance, are there other examples of labor costs that create errors in measurement of the PEG TFP?

A16. Yes. Consider the cost category under distribution operations defined by the uniform system of accounts Account No. 871 - Distribution Load Dispatching. This account represents the people who operate the system on a daily basis. This requirement may be outsourced to a third party, provided by a supplier or provided internally based on a variety of factors. The activities of these individuals differ from utility to utility as the result of a number of different supply alternatives and the type and number of different supply options available for the utility. Their work is complicated by the number of city gates, available primary and secondary delivery points for supplies, the number of pipeline suppliers, the services available from each supplier, the number and type of storage services under contract and the availability of peaking supplies such as LNG.

With respect to LNG the type of LNG storage and the technology for liquefaction or the scheduling of deliveries when LNG is trucked to the storage all contribute to the complexity of managing this critical function. Other storage services must be managed to assure reliable services as send-out and injection ratchets impact flexibility of storage and the availability of capacity to be used. This complex work requires both skills and experience. However, these costs may be included in gas cost when provided by a supplier. Further, these costs differ dramatically from one utility to the next based on all of the considerations noted above and other factors such as the number of customers delivering customer owned gas.

The fundamental point is that higher costs for one utility compared to lower cost for another does not mean that the second utility uses less inputs just that the inputs are included elsewhere and amounts to a measurement error under the PEG method. This is a small error but it is indicative of any number of other small errors in measurement across utilities that add up to large errors in the measurement of TFP when using the index method under the academic paradigm. The B&V process does not create this error unless the utility switched from one method to another during the sample period. If that happens, even the B&V approach is impacted by either increasing or decreasing inputs depending on how the switch occurred.

Q17. Why would the PEG estimate use such a measure of inputs?

A17. The answer lies directly in the use of the competitive model to develop the theory that underlies the academic paradigm and the absence of any consideration for the fundamental nature of regulated utilities. Since the labor input measure is not valid absent the assumptions that the technology and mix of labor employed are the same there can be no viable TFP estimate. This is not a problem for competitive industries because all firms use the same technologies and mix of labor types. The PEG reliance on the competitive model assumptions to estimate TFP cannot produce a meaningful and logical measure of expected TFP for regulated monopolies even if regulation over time may equate revenue to cost in the accounting sense. Further, that assumption is only correct by accident since it would require the utility to earn exactly its allowed return. It is important to note that this is not only a failing of the PEG model but also a failure of the academic paradigm to adapt to the unique characteristics of the utility industry.

Q18. Are there other errors in the estimation of the labor component resulting from the PEG approach?

A18. Yes. The source of error in this process is magnified when one considers the labor component of outside services for utilities. Among the activities that may be outsourced and thus paid for in outside services as opposed to being paid for in the distribution accounts are meter reading, tree trimming, various construction aspects such as main replacement, new construction build out and so forth. All of these items may be included in direct expense or in indirect expense with different cost consequences and different ways of measuring the same input labor. This issue and the issue of the price index are examples of measurement error from using an indirect measure of inputs and trying to aggregate the results across utilities into a single index value representing a diverse set of technologies, input prices, scale economies and business environments and failing to recognize the differences in output mix because of using only customers as a measure of output and input mix differences as noted above. This is one of the reasons that adapting the Kahn method for measuring TFP has appeal since it treats the unique circumstances for each utility separately thus avoiding the errors introduced by improper measurement of inputs in the PEG methodology.

Q19. Are there other causes of input measurement errors in the PEG methodology based on its assumptions?

A19. Yes. The input mix creates two problems for the indirect measurement of capital inputs, i.e., estimating the quantity of inputs by dividing costs by a price term. As discussed above the issues are as follows:

- The appropriate price index to use to divide into the costs to get units of input.
- The issue of the appropriate index to use to deflate the annual capital dollars.

PEG assumes that a regional index of construction prices is adequate for adjusting the nominal dollars of capital to real dollars. The use of any standard index would obviously not reflect the mix of inputs used for any one utility from year to year and could not possibly reflect a comparison of costs across utilities as noted by the authors of the Handy Whitman Index quoted above at page 10. A simple example will illustrate this point. Gas utilities use both steel and plastic main depending on a number of factors. While the size of the main may be the same, 2 inch pipe for example, each type of pipe and size has a different cost so each utility could have the same total cost but purchase different quantities of inputs. This difference would not show up in the PEG analysis of the real value of the plant investment leading to an incorrect measure of the capital inputs assuming that the price of capital is correctly estimated. Further, the capacity value of steel pipe differs from plastic because steel pipe can operate at higher pressures and thus adds more potential capacity to the system than a comparable size of plastic pipe. This is just pointing to the necessity to account for the realities of the utility business that require a departure from the pure academic model. It is far more difficult to model reality than it is to assume away the messy problems and produce a stylized version of TFP that is not reflective of anything other than the assumptions that abstract from the reality.

<u>Section Three- PEG Data Errors in TFP Study</u>

Q20. Have you discovered errors in the PEG data used to develop the TFP estimates?

A20. Yes. There are a number of significant data errors in the PEG data set that underlies their TFP estimate related to the output measure - number of customers - and to input measures. There are 44 errors in the number of customers or the output measure out of the 896 observations on 64 utilities. Some of these errors occur for a number of years for the same Company in the data set while some errors are for just one or two years for a company in the data set. Where these errors create large changes in output they either overestimate the TFP value or underestimate the value. The errors point to a lack of rigorous review of all of the data in the report.

Q21. How many companies are affected by the errors?

A21. The errors occur for ten of the 64 companies including Bay State Gas, Equitable Gas Company, Cascade Natural Gas, Corning Natural Gas Company, Mountaineer Gas Company, Northern Indiana Public Service Company, Northwest Natural Gas, Pacific Gas and Electric Company, South Jersey Gas and Washington Gas Light.

Q22. How did you identify these errors?

A22. Based on my experience and in some cases having worked for certain utilities or followed those utilities on other assignments, I reviewed the data for anomalies. Where the data looked to be unusual, I checked various data sources to determine if the data was reasonable. I have checked PSC reports, SEC 10-K reports, company annual reports and Pipeline and Hazardous Materials Safety Administration Reports to determine if the data is accurate. For each of these utilities the measure of output was incorrect in one or more years where the reported number of customers was too high or too low as reported in the PEG analysis. A simple example will illustrate how the need to check the data was triggered. For South Jersey Gas, the Company highlights customer growth in its annual report noting that they added its 300,000th customer in 2003. Since PEG's reported data for that company in 2003 and 2004 had customer counts in excess of 400,000 customers those numbers could not be correct. In checking those numbers, the actual customer counts for PEG data years 2000, 2001 and 2003 based on the SEC Form 10-K filings were all in error. In addition, there were errors in other years.

The problem with each of the errors is that it impacts the measurement of the change in output for one or two periods. Obviously if the measurement error is in 1998 the value only impacts customer growth in one year. In any other year customer growth is impacted for two years and the output measure is incorrect twice. Since TFP is measured by the change in output less the change in input these changes would include a large increase or decrease in output that cannot be explained by the change in inputs.

When the number of customers is incorrect, the measure change in output (essentially the difference in the number of customers each year) is either larger or smaller than the actual change. For example, the PEG data shows an increase in output for South Jersey Gas from 2002 to 2003 of 33.55%. Using the correct customer count for 2003 of 304,562 customers that change becomes 2.72% using the PEG logarithmic formula. This reduces the change in output for 2003 by over 12 times. That change also reduces the TFP measure and the overall average of TFP measures. In a number of cases, PEG shows a decline in growth of output when the growth is actually positive. It also shows positive growth in some years when the growth is negative. Data errors cause results to be inaccurate.

Q23. Are there errors in the costs used to measure inputs?

A23. Yes. PEG apparently did not review the O&M dollars used to estimate inputs as they have included costs recorded on the utilities' books that were never part of the revenue requirement and as a result have created unreasonable estimates of the changes in inputs for a TFP estimate based on the revenue requirements. For example, PEG uses data for the Columbia gas companies that include the impacts of the NiSource acquisition of the Columbia Energy Group and the subsequent restructuring of the operating utilities. The clearest evidence of the restructuring impact can be found by looking at Columbia Gas of Ohio where the PEG operating costs used to determine the O&M related inputs changes dramatically for the period including 2001. The acquisition closed in the fall of 2000 and restructuring charges were taken in 2001 resulting in an increase in costs that would not have been included in revenue requirements but would be recognized on the books. This is one of the problems that results from failure to understand the accounting principles as they relate to revenue requirements.

The result of the abnormally high expenses based on the inclusion of restructuring costs resulted in a significant reduction in costs in 2002 including a 43.9 percent decline in the measure of input. Since these costs are not related to the production of output the costs should either be excluded (a virtually impossible task without much more detailed accounting records for the utility) or the exclusion of the companies impacted by the acquisition from the sample or the sample period should be shortened to permit the operational issues to become more normalized. In any event the measure of input level after an acquisition may cause unreasonable results for the input measure since the restructuring costs were not required to produce the measure of output.

Since the potential impact of a merger or acquisition cannot be easily discerned from the data included in utility data bases, this activity creates measurement error in the resulting index and impacts a number of both the gas and electric utilities in the sample during the period. For the PEG gas sample, 22 utilities have been acquired during the period and several of the utilities have been acquired more than once. For the PEG electric sample, 17 utilities have been acquired during the study period. There is no indication that PEG even considered the impact of acquisition in any way. Failure to adjust out the non-revenue requirement costs causes both an overstatement of input growth and a subsequent large reduction in input growth for the years where restructuring charges were taken. This flows through to the TFP calculation by artificially increasing and then decreasing the measure of inputs to be deducted from outputs thus increasing and decreasing TFP yearly estimates without actually measuring the real impact of physical inputs which did not change in the same magnitude as suggested by the restructuring charges.

This is a significant problem for selecting longer periods for estimating TFP. For the B&V analysis the merger and acquisition activity was minimal with some transactions starting but not completed in the sample period and others occurring earlier in the period for only a limited number in our sample. Further these transactions in general slowed for the B&V study period.

Section Four- Issues Related to the Impact of Capital on the Calculation of the X-Factor

Q24. Please provide a general summary of your comments related to the calculation of the X-factor by PEG.

A24. There are two fundamental flaws with respect to PEG's analysis of capital inputs that results in a significant upward bias in the TFP results it has calculated. As a practical matter, the X-Factor recommendation resulting from PEG's analysis is not logically sound and amounts to a confiscatory rate path for both FEI and FBC if his results were accepted as noted above and explained in detail in Section 6 below.

As noted above, the use of the academic paradigm is about theory and assumptions and this is the source of the most significant issues with PEG's testimony. While academic models may provide useful insight based in the context of all of the assumptions that underlie the theoretical model, rate cases are about evidence and facts not theory and assumptions. To the extent that evidence contradicts the assumptions, results of an academic analysis provide no economic-theoretic interpretation and cannot be used as the basis for establishing an X-Factor in a rate proceeding because the results are meaningless. Further, unless the evidence in support of the theoretical approach can demonstrate that the results provide a reasonable opportunity for the utility to earn its allowed return the model is useless.

PEG has not attempted to show that its proposal will allow a reasonable opportunity to earn the allowed return but rather admits that the analysis required demonstrating this fact is beyond their capability[4]. By understanding that the assumptions required for the academic paradigm cannot be justified in the real world because evidence contradicts those assumptions, it is necessary to find another alternative to measure TFP. The alternative must not rely on a myriad of unproven assumptions but rather must take a more practical approach to reflect the real world economics of the utility business as I have done in the analysis of the X-Factor filed by the Companies. It is not always necessary to use complex, black box analyses to develop a basic understanding of complex economic theory as it is applied in the real world.

Q25. Please explain why PEG's model is not logically sound and would result in a confiscatory rate path for both FEI and FBC.

A25. Having a positive TFP result as the basis for an X-Factor flies in the face of logic because it makes a number of implicit assumptions that do not apply in the case of FEI and FBC. First, it assumes

[4] See the PEG response to BCUC 1.23.1.

that these companies have no history with PBR. While utilities with no experience with PBR may have numerous opportunities to improve efficiency at relative minor costs, this so called "low hanging fruit" has been captured by FBC and FEI over earlier PBR periods. Basic economics supports the conclusion that after numerous years under PBR Plans, the available efficiency gains are more difficult and costly to obtain. This is known as the law of diminishing returns[5] and applies in the management and operation of electric and gas utilities.

Second, the economics of infrastructure replacement, all else equal, requires a rate trajectory greater than the rate of inflation just based on the revenue requirements associated with a growth in rate base without any offsetting growth in revenues absent the rate increase required to support the new plant. In the context of TFP, physical inputs of pipes, valves, regulators and so forth increase with no change in outputs as measured by customers or capacity for the system. If output remains constant and inputs in the physical sense increase the only logical conclusion is that TFP must be negative. The empirical results that PEG uses to dispute this finding are not based on a correct understanding of the life cycle of inputs nor a reasonable measure of growth in physical inputs.[6]

Finally Dr. Lowry has indicated in his own prior testimony that infrastructure replacement has the impact I describe as I discuss below.

Q26. Dr. Lowry questions your conclusion that infrastructure replacement is a significant issue going forward and even seems to argue that his empirical results disprove the role of infrastructure replacement in producing negative TFP results[7]. Is there support for your position on infrastructure replacement?

A26. Yes. In May of 2013, I presented a paper at the Eastern Conference of the Center for Research in Regulated Industries of Rutgers University entitled "Managing the Rate Impacts of Infrastructure Replacement". In that paper, I referenced the capital cost of just a portion of infrastructure replacement as reported by EEI and AGA. These numbers were $20 billion per year for electric T&D infrastructure (EEI) and $7 billion per year for critical gas industry safety infrastructure (AGA) over the next ten years. In any case the issue is factually a major issue for utilities. Since these investments are above and beyond the normal capital expenditures required to grow and maintain the system there will be rate impacts in excess of the rate of inflation as evidenced by the proliferation of rate recovery mechanisms for infrastructure replacement costs.

Second, Black & Veatch conducts client surveys for both gas and electric utilities each year to assess the issues that executives in the industry feel are important. In 2013 much like 2012 the

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[5] It should be noted that this same law applies in the context of other elements of the plan such as the recommendations from Ms. Alexander related to SQIs as discussed later in my testimony.

[6] TFP is designed to measure the changes in physical inputs and outputs and the indirect measure used by PEG does not come close to the actual measurement of physical inputs as I demonstrate below.

[7] PEG Report page 67

issues of reliability and aging infrastructure were among the top five issues for both electric utilities and gas LDCs.

Importantly, even the National Association of Regulatory Utility Commissioners (NARUC) has recognized this issue with the following resolution in 2013:

> RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners… ***encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question***; and be it further;
>
> RESOLVED, That State commissions should explore, examine, and ***consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems.*** (Emphasis added.)

Finally, Dr. Lowry's own evidence provided in response to FEI-FBC IR 3-26 Gas shows that accelerated main replacement is occurring over the period of 2007 through 2011 as B&V has noted. The PEG average change in real investment for the years 2007 through 2011 is some 77% higher than the average for the years prior to 2007 based on the PEG data.

Dr. Lowry is simply wrong on the importance and impact of this issue and as I will discuss also wrong on his estimates of TFP and his recommendation for an X-Factor based on his various changes in calculations and methodology as discussed below in Section 5.

Q27. You have indicated that Dr. Lowry has previously reached a similar conclusion regarding infrastructure replacement. Please provide examples of such conclusions.

A27. In Testimony filed before the Maine Public Service Commission in the matter of Maine Power Company (Docket No. 2007-215) - Section 2, Page 9-10 Dr. Lowry makes the following statement:

> Another short-run determinant of TFP growth is the intertemporal pattern of expenditures that must be made periodically but need not be made yearly. Expenditures of this kind include those for <u>replacement investment</u> and maintenance. A surge in such expenditures can slow productivity growth and <u>even result in a productivity decline</u>. Uneven spending is one of the reasons why the TFP growth of individual utilities is often more volatile than the TFP growth of the corresponding industry. (Emphasis added.)

Dr. Lowry also used this same statement in a docket before the Vermont Public Service Board in the matter of Central Vermont Public Service (Docket No, 7336) – Page 7. While not using the term infrastructure replacement directly the replacement investment is the definition of infrastructure replacement. Further, infrastructure replacement plans are not one year plans but rather represent multi-year plans of ten to twenty years.

In testimony on behalf of Potomac Electric Power Company (PEPCO Case No. 9286) in 2011, Dr. Lowry discussed precedents for expedited CAPEX cost recovery. The following represents selected quotations from that testimony found at pages 61 and 62 of the filing:

> It can be seen that that there are precedents in numerous states … for power distribution CAPEX most commonly to recover the cost of AMI or more general accelerated modernization programs that improve reliability.
>
> … Many gas distributors have CAPEX cost recovery mechanisms. Expedited CAPEX cost recovery helps gas distributors accelerate the replacement of these old facilities. (Emphasis added.)

In testimony before the Delaware Public Service Commission in a Delmarva Power and Light Company case Docket No. 11-528 at page 6 Dr. Lowry stated the following:

> Productivity growth … but is temporarily slowed by an accelerated modernization program since this causes the rate base to grow more rapidly. A slowdown in productivity growth causes cost to grow more rapidly. (Emphasis added.)

In a case before the Washington Utilities and Transportation Commission on behalf of Avista Corporation Dr. Lowry stated:

> Some CAPEX programs involve assets that generate no revenue automatically and are not "lumpy" so that assets of smaller but still sizable value become used and useful each year over a sequence of years. Examples include programs to replace aging distribution and transmission assets… As discussed more fully in the testimony of Mr. DeFelice, CAPEX is forecasted to continue at high levels well beyond 2013, the year that new rates will be in effect. A sizable portion of the CAPEX generates no new revenue automatically and is producing a stream of newly used and useful assets over several years. (Emphasis added.)

All of this testimony references the importance of infrastructure replacement for both gas and electric utilities and its impact on the productivity of the industry currently and into the future and contradicts the PEG Report statements related to both gas and electricity.

Q28. Is there evidence from other jurisdictions that demonstrate current negative values for the X-Factor in gas and electric utilities?

A28. Yes. There are a number of cases where the approved X-Factors for gas and electric utilities are negative. The negative X-Factors in decisions by the Australian regulator where the regulator has adopted negative X-Factors albeit determined in a different way relying on the data for a single utility. These derivations are the result of providing the utilities with a set of adjustment factors (the X-Factor in the equation I-X) designed to allow the utility to recover costs and earn a return based on expected costs to operate across the regulatory control period. This method is similar to the evidence that both FEI and FBC have filed that indicate that the X-Factor proposed by the Companies of 0.5 is indeed a stretch for the Companies. I have attached excerpts from regulatory decisions that demonstrate the adoption of negative X-Factors for major utilities in Australia as Schedule HEO-1 Rebuttal. Those excerpts show that the ten utilities in question have negative X-Factors that are larger than the X-Factor estimates developed in the B&V report in some cases and confirm that the small positive X-Factor of 0.5 percent proposed by FEI and FBC is far above the actual approved X-Factors in those cases. Dr. Lowry has also recommended a zero X-Factor in his report for the Ontario electric utilities for the going forward period but recommended a positive X-Factor for FBC.

Q29. You have indicated that PEG has not provided the most up-to-date analysis of the academic paradigm, please explain.

A29. In 2009, Dr. Erwin Diewert, Dr. Denis Lawrence and Mr. John Fallon provided a series of reports to regulatory bodies that advanced the academic paradigm to reflect the impact of sunk costs on the development of the appropriate TFP values for gas and electric utilities[8]. Dr. Lowry has not accounted for this issue in the report filed on behalf of CEC. As a note to this issue, I will discuss the full impact of sunk costs on the academic paradigm below. Suffice it to say at this point, ignoring the impact of sunk costs in the estimation of TFP, creates a bias in the analysis that causes Dr. Lowry to estimate TFP at a level greater than it actually is.

Second, Dr. Lowry does not account for the extensive discussion in the literature associated with the use of both billed and unbilled outputs in the measure of the output component of the TFP analysis[9]. The principal unbilled output discussed in the literature is a measure of the capacity component of output, and as the case here, is not billed for most customers. The output measure for system capacity has been discussed at length by Dr. Lawrence in numerous TFP study filings both in Australia and New Zealand[10]. Despite the importance of these developments, Dr. Lowry has not adjusted his academic models to reflect in any way the significance of these developments. In fact, Dr. Lowry chose to use only the number of customers to measure output.

[8] The theory of network regulation in the presence of sunk costs, Technical report prepared for the Commerce Commission, Erwin Diewert, Denis Lawrence and John Fallon, August 5, 2009; Asset valuation and productivity–based regulation taking account of sunk costs and financial capital maintenance, Report prepared for the Commerce Commission, Erwin Diewert, Denis Lawrence and John Fallon, June 11, 2009

[9] The concept of billed and unbilled outputs recognizes that only a very small number of larger customers are billed for capacity and that capacity is a significant output measure that must be included in a reasonable TFP analysis.

[10] Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity, Initial report prepared for the Commerce Commission, Denis Lawrence, John Kain and Tim Coelli, February 10, 2011; The Total Factor Productivity Performance of Victoria's Gas Distribution Industry, Report prepared for Envestra Victoria, Multinet and SP AusNet, Denis Lawrence and John Kain, March 26, 2012

By itself, the number of customers does not properly measure the required inputs to produce the different output mix for either electric or gas utilities because it ignores the impact of growth on the requirement for more delivery capacity. No net new customer is ever added to the utility system without the expansion of some elements of capacity. Also, net new customers does not measure the actual number of new facilities required to serve customers. Since the attachment of gross new customers all require new inputs the customer measure does not properly account for new additions. This problem is solved in part by using the capacity measure in the B&V study because the growth in two inch pipe is directly customer related in the output measure. It also should be noted that PEG filed a recent study in Ontario where it used both customers and capacity as part of the measure of output that showed electric productivity growth to result in a negative TFP value and a PEG recommendation of a zero value for the X-Factor.

Q30. Please discuss the errors in PEG's estimation of capital inputs and the impact on the academic estimate of TFP.

A30. PEG has made a number of assumptions related to the measure of the capital input that are inconsistent with the actual measure of physical input and importantly the method for measuring the price of capital is inconsistent with the regulatory model and the latest development related to Financial Capital Maintenance[11]. PEG uses an indirect method for estimating the quantity of capital. This indirect method relies on calculating the level of inputs used as the trend in real cost divided by the trend in prices. In the case of capital PEG performs a detailed calculation of the price of capital as explained in Appendix A-4. As explained in that appendix, the purpose of the price of capital calculation is to estimate the quantity of plant used in each year as an input for capital[12].

There are serious issues associated with this derivation of the input quantity of capital for a regulated firm. First, PEG assumes that depreciation is a straight line calculation (equivalent to the typical accounting depreciation used for determining rate base in a regulated environment although not equivalent to the depreciation for tax purposes or to economic depreciation). Under this calculation, PEG assumes that the measure of input deteriorates at the rate of 100% divided by the value of the average life of the asset. Using the 41 year life assumed by PEG, the service flow value of an asset declines by about 2.44% per year and there is no service flow value for an asset older than 41 years. That is, if a gas LDC has pipe older than 41 years, the input value of that pipe is assumed to be zero for purposes of the input index used in the report. This has the effect of reducing the actual level of inputs for purposes of measuring TFP for each gas utility in the sample to a level of input that could not physically meet the design day requirements of the utility. Since the TFP measure calculated by PEG cannot physically meet the requirements of customers, the changes in input cannot match the change in output in any

11 Diewert, Lawrence and Fallon, op. cit.

12 This calculation relies on Shepard's lemma that under certain assumptions the cost function can be used to derive the input demand function. This concept is sometimes referred to as a duality theorem.

physical sense. This artificially raises the TFP value by showing a smaller change in actual input than really occurs.

For example, PEG reduces the level of input for Hope Natural Gas in West Virginia by about 47 percent of the actual inputs used in 2011, the last year of the study. These excluded pipes are required to serve customers. The 47% of pipelines excluded because they are older than 41 years results simply by the effect of the calculation of capital inputs and has the direct effect of increasing the TFP estimate because of an unrealistic, unwarranted assumption that is not supported by the engineering and operating reality of the gas LDC[13]. Using Hope Natural Gas as the example, Hope has added miles of pipe each year that increase the system capacity and serve net new customers[14]. That is, both inputs and outputs have increased although the composite output must also reflect a decrease in the number of customers. That decrease in output is necessary because customer count is a net measure of customers reflecting both the addition and loss of customers. Adding customers that require new services and even main for most of those customers means miles of new pipe additions and therefore new capacity. These new inputs, however, are not included in PEG's estimate of capital additions because the 2.44 percent reduction in capital assets is greater than the actual miles of pipe added to the system in each year. This means that under PEG's model, inputs decline more than the decline in customer growth by a factor of over six times. This results in a positive TFP from a lower growth in physical inputs even though it is a factually incorrect result flowing solely from the erroneous and physically impossible assumption regarding the measurement of capital input less than the used and useful amount of plant employed to actually serve customers.

PEG simply makes an assumption that can only produce a positive value of TFP because it fails to recognize that infrastructure has the same type of depreciation as a structure. The service value of the infrastructure is unchanged by age so long as the facilities are maintained in good working order[15]. To illustrate the reasonableness of this conclusion, the following table provides a listing of the factors that impact the flow of gas through the pipeline system under the IGT Distribution Equation. This equation is used by gas planning engineers to determine the size of pipe required to serve load while maintaining minimum system pressures under design day conditions to provide reliable service. It represents the method for calculating the change in system capacity from the addition of pipe miles by size and operating pressure.

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13 See Application pages 211-212 that shows this assumption is invalid.

14 Net new customers are defined as customers for whom at least a new service line and meter are installed to attach the customer to the system.

15 See for example Appendix C-3 of the filing that provides evidence that time is not a cause of decline in service value and that expected pipe failure is the only reason for replacing otherwise productive pipe.

Table 1

Components of the IGT Distribution Equation

Parameters
Inlet pressure (absolute)
Outlet pressure (absolute)
Pressure, standard condition (absolute)
Temperature standard condition (absolute)
Mean temperature of line (absolute)
Inside diameter
Pipe length
Gas relative density (air=1)
Mean gas compressibility
Pipeline efficiency
Mean gas viscosity
Elevation of exit above entrance

This equation contains no term that relates to the age of the pipe. With the exception of the term Pipeline Efficiency, all terms are determined exogenously. Pipeline efficiency relates to the inside of the pipe relative to the smoothness factor resulting from the manufacture of the line. That term does not change over time since a well maintained line has no internal changes as the result of gas delivery.

Further, there is ample empirical evidence that physical assets such as pipelines do not deteriorate as hypothesized by PEG because the design day requirement of a gas LDC is met making use of assets that for book purposes are fully depreciated. This conclusion holds for the entire LDC population of the United States where over 39 percent of all gas main in service in 2011 is older than 41 years[16]. The same is true for electric assets as well although it is somewhat harder to measure because electric utilities do not report this age information like gas LDCs provide annually. The result of this incorrect measure of capital inputs results in an upward bias in the academic estimate of TFP and causes the recommended X-Factor provided by the PEG testimony to be meaningless.

Second, PEG uses the Handy-Whitman Index to convert plant costs into real rather than nominal values. This is not a sound method for adjusting prices over time. Coelli, et. al., note this in their text on efficiency and productivity when they conclude:

[16] 2011 PHMSA Report for all gas LDCs in the U.S. representing over 1400 LDCs some of which are not even 41 years old.

> If you are working with a long time series data, it is appropriate that you make use of a chain index. In any case it is important not to use an index that makes use of a base period which is too far from the current period[17].

The Handy-Whitman Index is a fixed base index using 1973 as the base which is nearly 40 years removed from the last year of the PEG data. The reason that the index value is important is that if the deflator is wrong then the result is an inappropriate input quantity measure even if all other factors in the input analysis were correct and they are not as noted above. It should also be noted that over this period there have been major changes in the technology for installing and replacing mains including live insertion and directional drilling. As noted by the developers of the Handy Whitman Index and cited above, these elements are not reflected in the index.

Q31. Are there other reasons that using the Handy-Whitman regional index as the basis for determining the quantity of capital cannot be relied upon as a reasonable estimator for the prices incurred by each utility in a region?

A31. Yes. In addition to the underlying company specific business and operating conditions that impact costs, there are other factors that cause the quantity of the capital input to vary resulting in far different capital costs per mile of main or service line (the two largest components of distribution capital). This is the input mix factor as noted above. To illustrate the differences in main costs within a Handy-Whitman region, Table 2 below provides the cost per foot of main installed in 2010 for each utility in the PEG sample that operates in the Handy-Whitman North Central Region.

[17] An Introduction to Efficiency and Productivity Analysis, Second Edition, Timothy J. Coelli, D. S. Prasada Rao, Christopher J. O'Donnell and George Battese, Springer, February, 2006, p. 155

Table 2

Cost per Foot of Main Handy-Whitman North Central Region Utilities

Pipeline Main Additions, Calendar Year 2010

Company	Miles of Distribution Main Added	Gross Plant Additions for Distribution Mains	Cost per foot of additional Mains	Difference between Actual Cost and Average Cost
Columbia Gas of Ohio	30.0	$ 30,139,991	190	-91
Consumers Energy Company	0.0	14,182,992		
Duke Energy of Ohio	7.7	55,207,994	1,350	1,068
East Ohio Gas	30.2	66,940,168	420	139
Indiana Gas Company	26.0	5,486,123	40	-242
Laclede Gas	0.0	16,090,018		
Madison Gas & Electric Company	13.0	4,321,481	63	-219
Michigan Consolidated Gas Company	48.0	24,128,123	95	-186
North Shore Gas Company	73.8	3,776,683	10	-272
Northern Illinois Gas Company	16.0	56,320,479	667	385
Northern Indiana Public Service Company	5.0	11,304,875	430	148
Northern States Power Company Wisconsin	6.0	4,212,528	133	-149
Ohio Gas Company	4.5	2,015,145	85	-197
Ohio Valley Gas Corporation	0.0	479,190		
Peoples Natural Gas Company	0.0	14,003,554		
Southern Indiana Gas & Electric Company	8.0	3,449,938	82	-200
Wisconsin Gas LLC	39.0	19,705,149	96	-186

Average Cost per Foot of Main	**282**

As the table illustrates the cost variances for each utility are significantly different. As a result of the wide variance, a single regional index produces an unreasonable estimate of the quantity of capital. Even within a single state the relative costs are different as well. PEG's estimate of the quantity of capital cannot be used because it produces arbitrary comparisons between utilities across the sample that does not measure the actual physical input. Based on my experience, this is not an unusual or a surprising result as we find these variances also exist within a single utility based on differing parts of the service area. The differences are even found for installing the same size of pipe that has the same cost per foot for the pipe component but not the same installation cost. This is a further reason that the estimate of capital inputs in the PEG study is unreliable and biased to produce a positive TFP.

As an added note, the table also shows that four of these utilities added $44.8 million in plant without adding any net miles of main and yet the PEG report shows a positive partial factor productivity index for three of the four utilities. This is a perfect example of infrastructure replacement investment that PEG does not believe is occurring and an example of the inherent bias in the estimation of the X-Factor prepared by PEG. The B&V approach correctly recognizes these added costs and the static output because the output measure capacity measures the change based on the underlying miles of pipe by size and operating pressure and measures the inputs by changes in net plant.

Q32. Is there another fundamental problem with the Handy Whitman Index when it comes to the input mix?

A32. Yes. The Handy Whitman Index also provides sub-indexes for different types of main installed. Table 3 below illustrates the differences in the cost for steel and plastic main in the period used by PEG. It is easily seen that different input mixes would result in a different composite index for each utility and this invalidates the use of a single index for each utility in a region as the basis for determining the real value of the costs incurred. If that value is wrong, the input quantity is wrong as the result of measurement error.

Table 3
Comparison of Handy Whitman Indices for Steel and Plastic Main

Year	Steel Index	Percent Change	Plastic Index	Percent Change
1998	363		341	
1998.5	366	0.83%	344	0.88%
1999	370	1.09%	346	0.58%
1999.5	373	0.81%	351	1.45%
2000	392	5.09%	354	0.85%
2000.5	396	1.02%	357	0.85%
2001	400	1.01%	364	1.96%
2001.5	405	1.25%	367	0.82%
2002	408	0.74%	369	0.54%
2002.5	411	0.74%	376	1.90%
2003	414	0.73%	376	0.00%
2003.5	414	0.00%	379	0.80%
2004	463	11.84%	389	2.64%
2004.5	482	4.10%	394	1.29%
2005	595	23.44%	411	4.31%
2005.5	590	-0.84%	421	2.43%
2006	624	5.76%	433	2.85%
2006.5	635	1.76%	440	1.62%
2007	607	-4.41%	460	4.55%
2007.5	611	0.66%	465	1.09%
2008	630	3.11%	480	3.23%
2008.5	729	15.71%	486	1.25%
2009	713	-2.19%	514	5.76%
2009.5	683	-4.21%	516	0.39%
2010	687	0.59%	502	-2.71%
2010.5	713	3.78%	502	0.00%
2011	760	6.59%	513	2.19%

Table 3 provides evidence that the changing pattern of cost for steel and plastic main is dramatically different over the PEG study period. Main is the single largest category of capital for gas LDCs and typically represents between 40 and 50 percent of distribution gross plant. Further, steel and plastic are also the most typical types of service lines. Including service lines with main would, in total, result in about 70 to 80 percent of distribution gross plant. The magnitude of the impact on the input measure of capital from assuming a single value for determining the real cost of plant would be quite large during this period. The B&V approach looks at both the new miles of pipe and the capacity measure from the size of pipe added. This method is not perfect since it uses the net miles of pipe but is superior to any method that makes no attempt to measure only net customer additions that cannot adequately address the growth in output. As an input measure, the B&V approach uses the change in net plant to track how inputs change and thus captures the issue of input mix directly.

Q33. Is there academic support for your view that the PEG depreciation of capital is incorrect?

A33. Yes. PEG has been criticized for using a variety of depreciation assumptions related to the service flow value of utility assets. In particular, testimony before the Commerce Commission (New Zealand) in 2009 concludes that "Note that although it is critical – given the characteristics of energy network assets – to use a service potential profile that reflects one-hoss shay deterioration in measuring the *capital input quantity*…."[18]. Emphasis added.

PEG discusses the one-hoss shay depreciation (using a constant capacity level for the pipe until the asset is physically retired regardless of the level of accounting cost depreciation) but rejects its use as a measure of the physical inputs for the utility[19].

Q34. Please describe the results of the PEG incorrect estimates of capital inputs.

A34. The correct specification for input quantity does not include the deterioration of capital as PEG has done. Since the capital inputs are critical to produce current outputs, regardless of the year of installation, PEG uses an inappropriate measure of capital input that significantly understates the actual changes in that input as discussed above. In fact, PEG shows low or declining capital inputs for half of the years in their sample despite the persistent growth in both capacity and customers across the sampled data. This is actually a physical impossibility since gas LDCs could not meet the design day requirements of customers under these conditions.

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[18] "Electricity Distribution Industry Productivity Analysis: 1996–2008", Denis Lawrence, Erwin Diewert, John Fallon and John Kain, p. 7

[19] It is useful to note that even this academic discussion is not precise since facilities operating below the MAOP can actually increase available capacity (output) simply by raising the operating pressure of the line. This also represents a potential refinement to the B&V method whereby the actual operating pressures would be used based on the average pressure by size and type of pipe instead of a theoretical standard operating pressure.

A similar result appears for electric utilities with negative growth in capital inputs in the later years and extremely low growth in inputs in the earlier years despite robust growth in outputs. Since all new customers require new capacity, it is not surprising to see persistent growth in capacity as measured by substations over the period. This same point illustrates the fundamental failure of the PEG study to measure the output mix of customers and capacity. Simply using customers only is a fatal flaw because the change in the number of customers without the measure of capacity does not properly recognize the difference in infill and system expansion customer mix. By adding a capacity measure both elements of the mix are included in the output. The PEG study does not recognize or account for this difference and thus the residual measure of TFP is incorrect. These errors lead to TFP estimates much higher than the actual TFP results that would occur if the capital input is measured properly.

Q35. Is PEG's assumption that the asset lives for utilities are the same for purposes of calculating productivity a reasonable assumption[20]?

A35. No. There are a number of reasons that such an assumption is incorrect. First, if asset lives were the same as stated in the PEG report, there would be no need for individual utilities to conduct depreciation studies to support the level of depreciation expense in their revenue requirements. Second, environmental factors influence the expected life of utility assets and those factors vary from utility to utility and even within the same utility. Third, the different mix of assets used by each utility (the percentage of total pipe that is plastic pipe) differs for many reasons such as historic growth rates, location of pipes on the system and so forth. This means that each utility has a different composite asset life. Using a single measure of depreciation life for purposes of measuring the price of capital is not a valid assumption and results in an incorrect indirect measure of physical capital inputs for each utility in the sample. The result is that TFP is significantly overstated as discussed above. The B&V methodology accounts for all of the pipe in the capacity output and reflects the impact on costs in the use of net plant as a measure of capital input.

Q36. Does the assumption about capital price used by PEG reflect the actual economic cost of capital?

A36. No. The PEG study states that the "components of capital cost include depreciation and the return on investment."[21] This statement is an example of PEG failing to consider all of the elements of capital cost because they excluded the component of net salvage from the cost. Net salvage may be either positive or negative depending on the asset class. For example for vehicles the net salvage would likely be positive while for assets that have a cost of removal and only scrap value net salvage would likely be negative. These types of values impact the actual depreciation rates for each utility in a different manner. Consider the definition of depreciation of the American Institute of Certified Public Accounts (AICPA):

[20] PEG Report Appendix A.4, pages 78 and 79
[21] "X-Factor Research for Fortis PBR Plans", p. 17

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

The use of straight line depreciation as a measure of physical input deterioration is not correct and PEG provides no recognition of the service value of assets in measuring capital productivity because PEG does not recognize that older plant still provides a full service value even though its costs are no longer part of the book value of assets. This is a material error that invalidates the results of the PEG study both theoretically and practically. As with other parts of the capital value estimate, this causes TFP to be overstated and this is a consistent bias in the PEG report.

Q37. Is PEG's use of an average capital structure and weighted average cost of capital valid for measuring the cost for each utility?

A37. No. This is another vestige of the competitive market model that does not apply for regulated utilities. Each utility faces its own cost of capital and as a result the price of capital that would be required to use the indirect measure of capital inputs. Since capital prices are determined administratively by regulation and are not based on the marginal cost of capital but on the embedded cost of capital, each utility has its own capital structure and its own cost of debt and equity.

The average price of capital PEG used to estimate capital input quantity is fundamentally flawed as well. Each utility faces its own cost of capital that differs from jurisdiction to jurisdiction for multi-jurisdictional utilities and for electric and gas divisions of the same utility. The use of a common capital structure and common debt and equity costs is arbitrary and inconsistent with the economics of each utility in the TFP study. By using an arbitrary capital price to determine capital quantity, the capital quantity cannot reflect either the actual physical quantity of capital or even a reasonable proxy value for input mix of each utility in the sample.

Q38. Is the basic model PEG relies upon to estimate the quantity of capital, namely the total cost of capital divided by a price index for capital equals the capital input used, a valid estimate of capital inputs for the utility industry?

A38. No. First, this model is based on a purely competitive market model. There is no question that this is not the model of the utility industry. The evidence that this model is based on the competitive model is that it assumes market based prices for capital that are the same across the industry allowing only for regional market differences.

Second, for this model to be valid, all utilities would need to use the same production technology set just like competitive firms that all use the same inputs to produce outputs. In that case, dividing total cost by price would equal the number of input units used just as theorized by PEG so long as the depreciation used the one-hoss shay (as discussed above) approach to properly reflect the physical life of inputs that do not have deteriorating service levels with age. However, utilities all use different technologies to produce outputs unique to their service area. The differences in technology result from a number of local factors that influence the cost of identical physical facilities being installed even within the same utility. Black & Veatch has filed evidence in cost of service filings that costs differ between suburban and urban main installation based on a variety of factors. It is also true for electric utilities that use different construction methods for transmission and distribution facilities based on the environmental factors such as requirements for undergrounding facilities in some areas (a factor that PEG recognizes). Further, some utilities use "tree wire" or other coated wire in areas with more trees to minimize outages or faults and reduce maintenance costs. This technology costs more that standard wires. The PEG methodology would measure this as more physical inputs not as a different quality of input based on a different technology.

The same might be said for electric utility costs where utility pole technology encompasses poles of different costs made from wood, concrete, steel, composite materials, etc. In addition, the size of poles (measured in both length and class) causes cost to be different and there is no one set of standardized pole length or class for each utility. A number of factors impact the length and class of pole installed. As a simple example, mounting a 50 kVa transformer on a utility pole typically requires not only a longer pole but a heavier class of pole thus a more costly pole. The mix of pole types effects costs and thus would show up as input differences not as quality and technology differences.

Simply dividing a price index into dollars does not produce a sensible or sound measure of the physical inputs actually used to serve customers. The net result is the competitive model assumptions do not apply and using an index across a utility sample does not properly recognize the differences in quality of inputs across utilities or the differences in technology sets employed by differing utilities. These input mix issues result directly from both environmental factors and from the differing sunk costs and regulated capital costs for utilities in different jurisdictions. Essentially, this means that the index methodology cannot be used across a sample of utilities because it cannot account for local operating environments or differing input mixes that result in the application of uniquely different technologies. The PEG results are unreliable on this basis as well. This is simply the case of a fundamental modeling error that invalidates all of the results in the PEG report and subsequent IR updates.

Q39. In the context of reviewing the capital inputs, does input mix vary with output mix?

A39. Yes. For both gas and electric utilities output mix based on both customers and capacity change the required mix of inputs and the costs of those inputs varies widely. A simple example will illustrate this point. For large industrial customers, gas utilities must build a customized meter run to measure capacity. The larger the capacity requirement on a design day (or on a Non-Coincident Peak day for non-firm customers) the more expensive the metering costs. Thus output mix on a customer basis alone cannot adequately explain the level of the input mix to serve customers since every utility has a different mix of customers. PEG does not address or develop a reasonable way to measure the different input mix required to serve differing output mixes. By ignoring the measures of these differences, the PEG estimate treats these differences as part of the unexplained TFP factor when they are not part of TFP but reflect measurement error and erroneous assumptions. This also biases TFP although it would be impossible to determine the actual direction of the bias without knowing the precise mix of outputs for each sample point. The B&V method makes the TFP calculation for each utility separately assuring that it is a consistent output mix being reflected in the calculations and that the output mix is measured by both customers and capacity that provides a proxy measure for the size of customers.

Q40. Is there a way to illustrate that the PEG capital inputs are incorrect as a matter of fact?

A40. Yes. In reviewing the PEG calculation of the change in inputs over this period PEG reports that on 371 occasions the quantity of capital inputs declined out of 832 observations or on 44.6% of all observations the change in the capital input was negative. This result follows from the cumulative impact of an improper deflator and an erroneous calculation of the capital price as discussed above. This would imply automatically that TFP would be positive for those observations since the formula is TFP equals a change in output minus a change in input. The subtraction of a negative value means adding to the TFP. It is relatively easy to test this result by reviewing either the physical miles of main additions or the gross capital investment. Using the PEG raw data from the report, the actual capital investment is positive in all but 92 periods. This means that even on a real basis capital inputs actually increased. More importantly, if one looks at the actual dollars expended those are positive for every utility in the sample for 2007 through 2011, the period for which B&V had collected the data on mains and services when PEG shows negative change in investment in real terms for 29 times. This is in contrast with the B&V results which use the growth in net plant to measure capital inputs and avoids the issue of large or significant numbers of negative changes in the capital input measure. Further, the B&V approach uses a single measure of all inputs that reflect every element of capital costs including negative salvage and positive salvage, and all of the O&M costs in one total input amount and compares that only in the context of the same set of factors reflected by each utility in the sample. This means only assuming the conditions for each utility reflect its own change in input and output mix and in the technology set. This is the only theoretically valid assumption for all the reasons discussed above.

Q41. Can the impact of CPCN on TFP be modeled by simply reducing the annual capital expenditures by a specific percentage reduction each year as PEG has done?

A41. No. CPCN typically represents capacity upgrades in the existing system or system expansions that add lumpy capacity to serve new customers. Capacity outputs, of course, are not measured by PEG in their report. PEG makes no adjustment to the measure of output (the number of customers) which means that PEG assumes that the reduction percentage does not impact the number of customers served. This is not a sound assumption when the percentage of new capital costs is between 70% and 80% for mains and services and that does not include meters and regulators. This means that there is no reasonable alternative to modeling CPCN without reducing the resulting output as measured by new customers in the PEG report. This is an example where the assumptions underlying the results are physically impossible and thus the increase in TFP is meaningless. Finally, there may be cases where the capacity added by the CPCN project is not justified on the need for capacity but the ability to reduce the costs for fuel or to access lower cost gas supplies. This means that CPCN in any form is not able to be reflected in the TFP study by arbitrarily reducing the capital costs.

Section Five- The Issues Related to the Impact of PEG Implicit and Explicit Assumptions on the Calculation of the X-Factor

Q42. Are there other issues with PEG's approach beyond those discussed above?

A42. Yes. The most fundamental issues associated with the academic approach relate directly to the underlying assumptions required to make the estimates of TFP. If we recall that the academic paradigm is based on a variety of assumptions, results are valid only so long as those assumptions are valid. In some cases the assumptions are so critical that if the assumption is invalid the methodology cannot be used. If the assumptions used to support the analysis are not valid then one must conclude that the results of the analysis are not valid and thus provide no evidentiary value to the determination of the X-Factor.

Q43. Please explain why the invalidity of the academic paradigm has not been an issue in prior regulatory proceedings.

A43. It is difficult to explain why the process of estimating TFP in a regulatory setting has not raised these issues in detail (at least in the United States and Canada) previously. In part, it may be that almost all of the work related to estimating TFP has been performed in the academic paradigm without a critical and detailed examination of the issues related to the economics of actual utility operations. The development associated with the ideas of alternative regulation has its beginning about 50 years ago. The I-X approach was introduced about 30 years ago. The development of the transcendental logarithmic production function also occurred about 30 years ago. Since that time there has been a gradual development of the theory as it relates to utility economics with nearly all of that development occurring in the academic environment. Presumably this is because of the detailed technical nature of the analysis. As a practical matter, the initial estimates of TFP relied on data that was readily available such as kWh or CCF to measure outputs. The estimates also relied on traditional economic assumptions that underlie production theory. As the use of these studies entered the regulatory process, engineers and utility economists begin to be exposed to the process and additional developments such as discussed above related to sunk costs and output measures became issues that were recognized by academic economists and these ideas were incorporated in the academic model although not by PEG. Since I have discussed these issues above, I will not continue that discussion here. Much of the development of the academic model has come as the result of the adoption of alternative regulation outside of North America but particularly in Australia and New Zealand as well as elsewhere. Although this work has been to alter the academic model, it has not always been as thorough in its analysis of the impact on basic assumptions as it should have been. For example, the development related to the inclusion of the concept of sunk cost only reflects a portion of the implication of sunk cost for the estimation of TFP using indexing methods as I will demonstrate below. It is within the context of regulation where evidence and not assumptions form the basis of analysis that the theory requires further development to reflect the application of the concept to the real world. It is only by bridging the gap between theory and reality that economic theory becomes useful in application.

The key to a sound approach under regulation understands both the principles of economics and the practical realties of the regulated industry and merging the two concepts to produce a reasonable result even if that result does not perfectly mirror all academic assumptions. Applying economics to analyze actual markets is never clean and easy just because the data being analyzed may not be perfect, economic actors do not have perfect information and so forth. In the academic model it is possible to assume away many of the intricacies of actual process. When those assumptions stray as far away from actual facts as in the case of the PEG method the only alternative is to reject the results and give no weight to the estimates of TFP.

Q44. Is there an overarching reason that the PEG Index Number method for estimating TFP cannot be used?

A44. Yes. In simplest terms, the index number method cannot be used when prices are not market prices as in the price of capital for a regulated entity or in the case where the behavior of the firms may not be optimal as is the case when the utility does not operate at either the minimum point on a short-run average total cost curve or the minimum point of the long-run average cost curve[22].

Q45. Is there an evidentiary basis for the two conclusions related to the fact that capital is not market priced and that utilities do not operate at the minimum point on a cost curve?

A45. Yes. With respect to the cost of capital (the capital price), it is determined by regulation based on embedded costs, accounting depreciation and an estimate of the market price of equity commensurate with risk and the underlying capital structure. This is not the economic or market price of capital as required to support index based measurement of TFP.

With respect to utilities not operating at the minimum point on a cost curve it is possible to illustrate this concept using basic cost curves to illustrate operating economics. Figure 1 below

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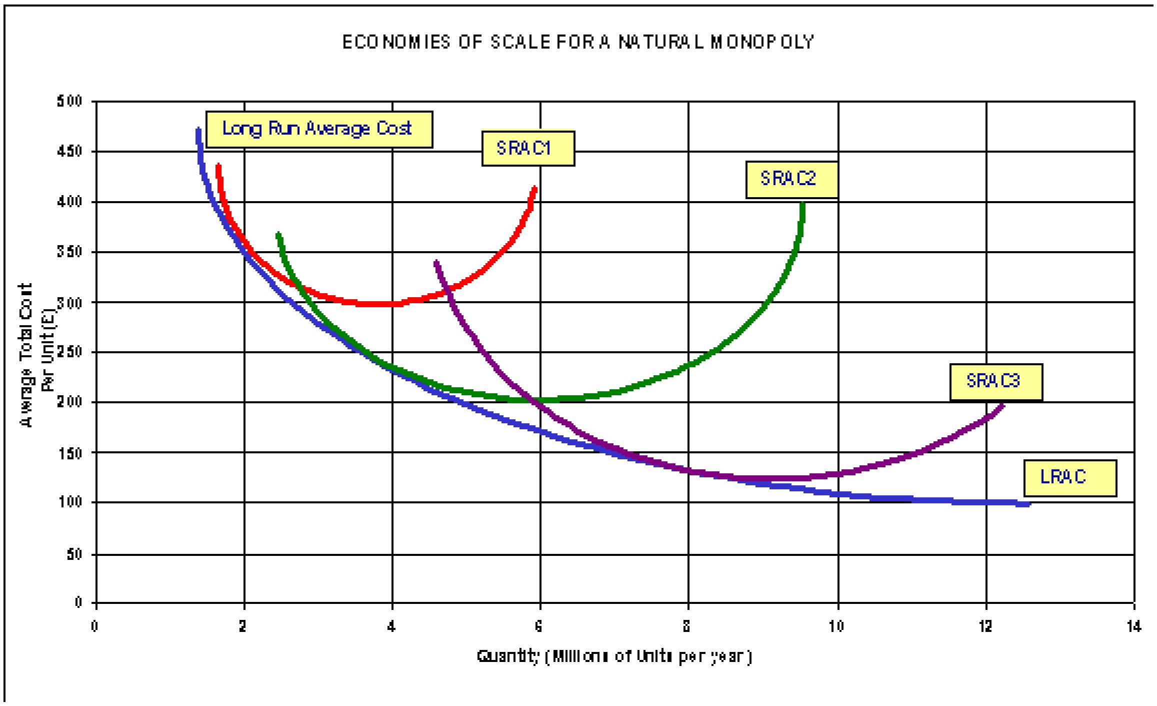
[22] An Introduction to Efficiency and Productivity Analysis, Second Edition, Timothy J. Coelli, D. S. Prasada Rao, Christopher J. O'Donnell and George Battese, Springer, February, 2006

is a graphical representation of both long-run and short-run cost curves for a natural monopoly such as electric or gas utilities.

Figure 3



When a utility reaches a point given by $350 of ATC and 2 million units of output, the utility will not continue to produce along the short-run cost curve to the minimum point because that is more costly (above the long-run cost curve). As a result, the utility will expand capital along the long-run cost curve to a new short-run cost curve. So long as economies of scale are not exhausted no regulated utility operates at the point of minimum average total cost but just moves to another short-run cost curve. That move results in lower ATC. It also is important to note that because of sunk costs (discussed in detail below) no two utilities will have the same short-run or long-run cost curves. Importantly, the movement from one short-run cost curve to another may actually occur much more frequently than might be expected because capital investments occur throughout the year as circumstances change resulting in multiple costs curves underlying the annual data used to measure productivity. It is a virtual certainty that no utility operates at the minimum point on its short-run cost curve as required by the PEG TFP analysis to estimate TFP. PEG does not recognize the importance of this distinction as it applies to the indirect measure of inputs and thus assumes that a single index based on industry average is appropriate for measuring both the real cost of inputs and the price of those inputs to divide into cost to measure an input quantity. The PEG method creates an error in the measurement of input quantities precisely because of the characteristics of the industry that require regulation and that cannot match inputs and outputs discretely in time because that does not minimize short-run costs but does result in proper long-run investments.

Q46. Does the issue of short-run and long-run costs create measurement problems for utility costs used in the PEG TFP studies?

A46. Typically the idea of marginal cost measures the change in costs associated with a change in output. Productivity studies that measure inputs indirectly measure the change in real costs divided by the price to determine input quantity to produce the change in output. The basic modeling error in the academic model used by PEG is that the measure of output is a change only in the current period output such as the number of customers. The change in input is actually designed to produce output beyond the amount needed in the current period and this is a sound reason for using a measure of capacity as part of the output measure since the capacity input miles of pipe by size allows for an estimate of the physical measure of the input required to produce the output for each firm based on their own operating pressures. (It is important to note that there are two pipe pressures that are important and differ for each utility - the normal operating pressure for a system and the maximum allowable operating pressures.) The marginal cost of the capacity of a transmission line (gas or electric) is the total cost divided by the units of capacity added to the system not the number of customers served or the change in transmission peak demand for the current period. This means that when measuring output as only the current change in customers the marginal or avoided costs would be overstated. This is an example that relates to the measurement of TFP because the measurement of the price using a current index of construction prices is not the basis for the decision to add the extra capacity (the lumpy addition) but rather the minimization of the long-run revenue requirement of the asset using the discounted present value of the stream of revenue requirements resulting from the addition of the asset. It is critical to include the capacity measure of output to avoid the error that the inputs differ based on the combination of outputs (the output mix) and the resulting measure of inputs does not properly explain the level of output resulting in a biased residual that includes a significant measurement error for both inputs and outputs. Unfortunately the PEG study gets neither of these concepts correctly measured and it is impossible to know the measure of the combined error even though we know the capital input error results in a higher TFP because of the underestimate of the change in capital inputs.

Q47. Please explain why the theoretical model used by PEG cannot be useful in the real world.

A47. The simple explanation for the failure of the theoretical model is that the fundamental assumptions of the model are not satisfied in the real world of utility economics. In fact, it is relatively easy to demonstrate the inapplicability to the real world simply by walking through PEG's testimony. To aid in that process the following table provides a list of assumptions that underlie the logic and analysis provided by PEG even though PEG failed to acknowledge the assumptions in their response to FEI-FBC 1.2.1. Instead the PEG response states "Assumptions like these might be pertinent were a productivity index used to estimate only the *technical change* in an industry or an economy[23]." This response is deficient simply based on the fact that

[23] Most TFP studies do not measure just technical change (the change in the technology set) but rather all of the factors discussed by PEG including scale economies, economic efficiency and output mix effects as part of TFP.

PEG explains the logic of the index approach relies on calculus which requires that functions be continuous to measure change. In discussing the assumptions that underlie the PEG analysis it will be necessary to show that the measure of change used to develop the index requires the assumptions for any conclusions to be valid. Each of the assumptions will be discussed separately to show why the assumption is both required and not valid for utility economics.

Table 3

Implicit Assumptions in the PEG Report Filed on Behalf of CEC in this Proceeding

1. Production functions are smooth and continuous
2. In any given year, all utilities use the same production technology set and that set changes from year to year
3. Input prices reflect marginal cost
4. The utility operates at the minimum point of a short run average total cost curve
5. PEG assumes that the utility operates with constant returns to scale in the short-run
6. Utilities are assumed to earn zero economic profit
7. The equation (6) in PEG's testimony Long Run (LR)Trend in Revenues = LR Trend in Costs implies that all of the following assumptions hold: Minimum LRATC= Minimum SRATC= LRMC=SRMC= Price and there are constant returns to scale
8. The assumption that Revenue equals Cost implies several assumptions: accounting depreciation equals economic depreciation, utilities earn their allowed return - no more and no less, the regulated return equals the market based opportunity cost of capital (the marginal price of capital), and that firms operate both technically and allocatively efficient.

Q48. Please explain why PEG's approach requires the assumption that production functions are smooth and continuous.

A48. At page 4 of the PEG evidence we find that PEG relies on principles of calculus to demonstrate basic index concepts. Yet when asked about this assumption, PEG responded that the assumption was unnecessary to the analysis[24]. They cannot have it both ways because either the proof of the index methodology requires the assumption or it does not. If the assumption is required for proving the index methodology is sound then if the data violates the assumption then the index methodology is not sound. This does not mean that economic theory cannot estimate TFP; it is still possible to estimate TFP just not with the method used by PEG and as noted above without the index paradigm.

It is this less than rigorous discussion of TFP coupled with a variety of data shortcomings and supported by the fact that a relatively minor change in the estimation methodology results in an

These assumptions are necessary for the underlying logic of the PEG index methodology to produce internally consistent estimates of TFP.

[24] See the response to FBC FEI-CEC-1-2.1.2 for the non-response to this IR.

increase of capital PFP from 0.98% to 2.25% or an increase in productivity of 2.3 times for the same companies with the same outputs. These different results are purely a function of a different measure of capital inputs that further understates the actual physical inputs used in each year.

It is relatively simple to show that certain conditions of production for gas and electric utilities assure that the production set cannot be continuous or smooth. To demonstrate this concept it is necessary to understand basic utility economics as it relates to meeting customer load with long-lived, sunk and lumpy capital additions based on non-market based, administratively determined prices for capital. It is not economic for a utility to carry every possible size of pipe or wire or utility poles or transformers in its inventory of capital equipment. Further, it is not economic to install a piece of equipment that will only serve the current load level for an installation where that would cause the utility to have to replace that capital asset with a forty year life every few years with larger and larger equipment to maintain adequate service levels in the area of that installation. This means that utilities use their experience to plan for capital equipment that will provide useful service levels for the life of that equipment because this minimizes cost in the long-run but not the short-run, albeit with certain risks related to forecasts, over the useful physical life of the asset. For this reason, the growth in capacity requirements of a utility never matches the actual amount of new capacity installed except in rare and unusual circumstances. Trying to match capacity growth and capacity investment in real time would mean both higher unit costs in the short-run and higher total costs in the long-run. Such a policy would also reduce the impact of scale economies on the long-run cost curve because the average physical life of utility assets almost certainly exceeds the average economic life of such assets[25].

Thus, there are three factors that every utility understands to cause their current production technology set to be lumpy (not smooth) and not continuous. The three factors are as follows:

- Capital added is always added in discrete increments.
- Capital is added based not only on current requirements but based on available technology.
- Capital is added based on the expected physical lifetime of that technology and the capacity to be served.

The importance of the capital price (rate of return of and on the asset) as determined by regulation is that this causes the utility to make its determination using that administratively determined cost relative to the actual marginal cost of that capital in the market which serves to distort allocative efficiency in the macro-economic sense but not in the regulatory context. That is, utilities make optimal decisions given the constraints they face but the decisions are suboptimal or second-best decisions from a social welfare perspective. It is that social welfare

[25] That is a new technology will likely be available before the end of the physical life of the asset. Cast iron pipe represents one such example.

perspective that PEG relies on to estimate the X-Factor using competitive market principles as opposed to regulated monopoly principles which represent the reality of the utility.

Q49. Please explain the issues related to PEG's assumptions related to the technology set.

A49. The technology set assumption issue in PEG's testimony is significant. To begin it is necessary to explain the significance of the production technology set. While in theory this concept is explained elegantly using set theoretic notation, it is simply a statement that a multi-output production technology can be defined by the combination of inputs used to produce those outputs and the output actually produced is part of the technology set. This is important for measuring productivity over time as technology changes there is a different technology set each year. PEG's index numbers rely on the assumption that this technology set is the same for each utility in the sample in any given year and that all utilities are measured against that technology set as discussed above related to index and price measures. The reason that this assumption is required is because they use a standardized index to measure real cost based on a specific set of inputs. Utilities with differing technology sets will use different inputs (the input mix) that would result in a point on a different cost curve that cannot be used to determine either the real cost of capital additions or the price of capital because of different expected lives of assets based on the type of asset. The PEG assumption is correct if the analysis was for a competitive market because capital moves freely and technology is not a barrier to entry. The implicit assumption in PEG's analysis is that capital is freely disposable and may be replaced each year. In the world of utility regulation it is precisely the absence of these competitive market features that leads to regulation even though PEG relies on the competitive paradigm for the basis of its analysis.

With respect to the assumption that utilities have the same technology set (as they would under the competitive market paradigm) it is relatively straight forward to prove that this assumption is not reflective of the real world and utility economics. There are many reasons that this assumption is not valid but for our purposes we will focus on four fundamental reasons:

1. Sunk costs
2. Lumpy capital additions
3. Administratively determined cost of capital
4. Operating environment conditions

With respect to these four reasons it can be shown conclusively that utilities do not operate with the same technology and further, it would not be economic for utilities to do so. We have alluded to the economics of operation above and will not repeat that analysis here. Rather, we will deal with each reason as it applies specifically to the issue of utilities operating with the same technology set. As a note, for convenience our comments will focus on the gas distribution business simply because there is a different level of data available in the public domain to support the conclusion that these factors preclude the possibility that any two utilities will operate with identical technologies except by accident. The same conclusion applies to electric utilities as well albeit the data is not reported in any manner conducive to actual measurement. Having worked for an electric utility holding company comprised of a number of previously independent utilities, I know that each utility used a different mix of inputs and different technologies even as entities in the same holding company.

As noted above, one of the more recent developments in the academic paradigm has been the recognition of sunk costs as an element to be considered in calculating TFP. It is certainly true that sunk costs have an impact on the estimate of TFP even under the academic model. There is, however, a more significant impact of sunk costs as it relates to the estimation of TFP using an index based methodology as PEG uses in this case - namely sunk costs mean that no two utilities use the same production technology set in any period. This is important because this means that the indexing methodology used by PEG cannot be relied upon at all for determining TFP because it has no economic meaning. Simply, PEG has compared apples to grapes and cherries and so forth with no reasonable basis for creating a basic index number since each utility has different inputs, outputs, input prices, technology, weighting factors for inputs and outputs all resulting in a meaningless index. This would be like calculating the CPI using different market baskets and different weights for each type of good and proclaiming that the result reflects the change in consumer prices for all consumers.

Q50. Please explain how sunk costs mean that no two utilities use the same technology to produce outputs in any period.

A50. The easiest explanation begins with a simple explanation of gas delivery technologies. Initially gas was delivered on a low pressure cast iron system. The delivery pressure beyond the meter has not changed over the years with respect to residential and small commercial applications. The inlet pressures for gas delivery systems have changed from low pressure to higher Maximum Allowable Operating Pressures (MAOP). Operating under lower pressures requires much larger pipes to deliver the same amount of gas as system operating under higher pressures. This can be seen by examining the basic gas delivery equation from Table 1 where both the inlet and the outlet pressure are elements of the equation as well as the inside diameter of the pipe. For cast iron pipes the low pressure system measures inlet and outlet pressures in inches of water column as opposed to PSIA (Pounds per Square Inch Absolute) or Pa (Pascal)[26]. This technology is still in use by some gas LDCs including some of those in the sample used by PEG. The following Table provides some examples of those utilities in PEG's gas LDC sample that used cast iron pipe in 2007 and 2011 as reported in the PHMSA data. Table 4 also shows the use of later technology such as bare steel and unprotected coated steel for those same utilities. The basic point of the table is to illustrate how sunk costs also impacts the technology set used by gas LDCs.

[26] Inches of water column can be converted to PSIA and would be very low numbers much lower than the typical measure of MAOP in a modern gas LDC system.

Table 4

Miles of Distribution Main by Technology

Company	Year	Bare Steel Main	Unprotected Coated Steel Main	Cast Iron and Ductile Iron Main
Alabama Gas Corporation	**2007**	655	523	1,081
	2011	634	517	930
Baltimore Gas and Electric	**2007**	86	0	1,363
	2011	67	0	1,333
Berkshire Gas	**2007**	35	63	95
	2011	28	30	92
Columbia Gas of Kentucky	**2007**	500	0	25
	2011	454	0	21
Hope Gas	**2007**	1,386	0	0
	2011	1,617	11	0
Northwest Natural Gas	**2007**	48	0	0
	2011	21	0	0
Peoples Gas System	**2007**	442	7	176
	2011	390	3	113
Peoples Natural Gas Company	**2007**	1,970	446	64
	2011	1,884	427	58
Virginia Natural Gas	**2007**	10	394	106
	2011	340	256	58
Washington Gas Light	**2007**	225	458	538
	2011	213	440	516

This is just one example of differing technologies used by utilities in the sample.

There are numerous other issues of different technologies being used as the result of sunk costs that are not always the sunk cost of the utility. For example, some utilities do not own all of the service lines in their service territory. The so called property line meter set represents a decision by customers to install and own their own service line. Service cannot be provided without the service line so there needs to be some recognition of this input in the measurement of TFP if we want to compare utilities using the index method preferred by PEG. Regardless of the service line ownership the utility is required to provide leak surveys and to require proper maintenance of customer owned service lines. In some jurisdictions, utilities have been ordered to repair and replace customer owned service lines as part of infrastructure replacement meaning adding new inputs not previously provided by the utility. Implementing this type of order would show up as a lower TFP value for those utilities, in fact, it would be a measurement error for the prior periods. The salient point of utilities not providing service lines is either the output measure must reflect the lower quality of the output or this customer provided input must be included in the analysis to correctly calculate TFP. This type of issue as well as different types of piping with different leak survey requirements impacts the level of inputs required by utilities to differ based on the types of sunk costs. On this basis PEG's calculated TFP is biased upward based on the utilities that do not provide all of the service lines for customers. This is a significant bias simply because the capital investment in service lines is the second highest plant investment behind mains for gas LDCs.

In addition, safety regulations have changed to require the installation of excess flow valves on all new and replaced service lines after 2010 under certain conditions. This change means that depending on the rate of infrastructure replacement either the output or input specification must also change. Using customers as a measure of output and failure to understand this added cost would also bias the TFP calculation as this change is implemented over time. A similar issue may occur for electric utilities where line extension policies are based on the cost of overhead service lines thus requiring underground services to make a contribution in aid of construction to have underground service that has lower maintenance costs and thus fewer inputs than overhead lines but not measured by the PEG study for either capital or O&M. The PEG study is deficient in assuming that all utilities use the same set of construction materials and techniques based on using the Handy-Whitman Index to deflate plant values to real terms and to determine inputs by dividing by an inappropriate capital price as discussed in detail above.

Q51. Since PEG's approach implicitly assumes no impact of sunk costs in any way, does sunk costs impact other decisions relative to the inputs required to provide service and hence the costs used to determine service levels by PEG?

A51. Yes. Several simple examples will illustrate that the level and types of inputs differ based on the characteristics of the sunk costs themselves and others on the operating environment noted above. As just mentioned different types of facilities have differing requirements for maintenance based on PHSMA rules[27]. Thus each utility based on its own unique mix of sunk costs will have different input requirements for operation and maintenance. When PEG analyzes the level of inputs required by dividing the costs by an index it implicitly assumes that the utilities are all using the same set of inputs and the same technology based on PEG's determination of the index value. Thus a utility with a higher mix of urban pipes that requires more frequent inspections will have higher costs because they use more inputs and different technologies but PEG will interpret that result in terms of lower productivity because its price deflator process assumes that the technology in that period is the same as every other utility. More inputs are required because of different technologies. Another example will illustrate this point in a more practical way. Consider the mix of customer density and how that impacts costs. (Remember that PEG relies on costs and the duality concept to estimate the level of inputs used to produce output so higher cost divided by the "price index" chosen by PEG equals the level of the input used to produce outputs as measured solely by the number of customers.)

[27] See for example PHMSA rules contained in PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS §192.723 Distribution systems: Leakage surveys that prescribes the frequency of surveys based on the location of the pipes.

Density has two impacts related to productivity: a scale effect and an input mix effect. The scale effect is related to the lower unit cost of output associated with the ability to install larger mains to provide the capacity output that PEG dismisses as unimportant. This scale effect is partially offset by the fact that the installed cost of capital for more densely populated areas is much higher than installation costs in the suburbs and other less densely populated areas. In addition, the operation and maintenance of gas main in urban areas requires different technology than for maintenance in more suburban areas. In the case of urban pipe maintenance the differences include much more hand digging to access the pipes, more traffic control and a variety of other regulatory and environmental issues. The simple point is that the types of sunk costs are themselves representative of different technologies and the types of different sunk cost facilities require different inputs to operate and maintain those assets. Even if this was the only difference it would assure that the technology set for each utility is different. Since there are other factors as discussed below, it is safe to conclude that no two utilities actually have the same technology set. The B&V analysis confines the measure of productivity within each utility and by not developing an index across utilities resolves the issue of sunk costs and the impact on technology choices because the utility knows its own options and invests in technology as those own costs and prices justify.

Q52. Since, as discussed above, PEG's analysis requires the same technology set, please explain how lumpy capital additions contribute to differing technology sets.

A52. The fact that each utility adds to its capital stock with lumpy additions over time explains in part why sunk costs differ from period to period and the differing technologies are reflected in the delivery service. In addition, the decisions related to lumpy capital additions changes the future rate of adoption of new technologies. If the utility installs an asset with a forty year life designed to serve the load growth with access to that facility over the forty years, there is no incentive for the utility to change to a new technology as long as the utility has that sunk cost and even longer if the asset continues to provide adequate, safe and reliable service. Lumpy capital additions imply that the utility has more capacity to serve load in the early years of service and that the amount of additional capacity from new technology is lessened as the result of that lumpy addition.

Capacity utilization is a factor discussed in the literature related to the academic model of TFP estimation. Nevertheless, the assumption that PEG is making that the production functions for each utility are the same in each period necessarily results in biased TFP estimates given the lumpy nature of capital additions. Again, the B&V analysis that uses a proper measure of output based on capacity resolves the lumpy capital additions problem altogether because it matches capacity with inputs measured by net plant for each utility independent of the others in the sample.

Q53. As indicated above, PEG's analysis assumes that the cost of capital is the same despite the administratively determined nature that directly impacts technology choices. Please explain

how administratively determined cost of capital results in production functions that are different across companies.

A53. To the extent that capital prices do not reflect the marginal cost of capital, the investment in new technology or even in better technology is distorted. Where capital and labor or capital and rents are substitutes for each other the optimum combination of inputs is determined by the ratio of prices as determined in the competitive market. When the cost of capital is set by regulation, it distorts the least cost decisions related to capital substitution and does not promote allocative efficiency. This is why we see utilities changing from ownership of assets to renting or leasing assets based on cost benefit analyses. This would occur where the lease expense passes through dollar for dollar but the capital return is below the market required return and thus all costs for ownership are not recovered. As a result the allocation of resources between capital and labor or capital and rents will be sub-optimal. The actual production technology will differ from utility to utility based on the nature of this distortion over many years. It is relatively straightforward to illustrate this concept by comparing specific technologies between utilities.

Take for example the adoption of a technology like remote meter reading. Remote meter reading, in its simplest form requires a device attached to the utility meter to read the meter and send the signal to a receiver which in turn uploads the data to a central computer for processing. It requires capital investment in back office assets, both hardware and software and in field assets both for reading the meter and for sending and receiving the signal. The largest source of savings is in labor cost to reduce the number of meter readers. Among other things, the size and density of the utility impacts the economics of using this technology along with the fully loaded cost of labor and the fixed capital costs for each component of the system. In low cost labor areas, smaller utilities may not find the economics of remote meter reading technology to be allocatively efficient. Whereas a large urban utility with a significant number of indoor meters and potentially high crime areas may find the technology to be very economic. Both utilities produce the same bill for each customer but do so using different technologies as a result of the capital cost determination of the regulator. The capital cost consideration includes not only the allowed rate of return but the actual returns earned and the real opportunity cost of capital for the utility. Again, utilities make optimal decisions for the costs they face that result in a different technology set being employed by the utilities. In particular, utilities assess capital decision based on the marginal cost of capital and not the embedded cost of capital.

Incidentally, PEG uses a version of the embedded cost of capital in their analysis by taking the weighted average cost of debt for the sampled utilities. This is not the correct cost of capital based on the market because historic debt costs represent a sunk cost that cannot be changed. Further, PEG assumes that all utilities have the same market capital costs. Even a casual review of the cost of equity capital demonstrates that utilities do not have the same costs and the differences can be quite large as between micro-cap companies and large-cap companies as an example. PEG has both in their sample but assumes equal capital costs to measure the capital input. The B&V approach to measuring TFP avoids this issue as well since it treats each Company on its own and recognizes the different costs of capital by using an ex-post measure of capital costs.

Q54. PEG assumes the same technology mix while acknowledging that operating environment conditions impact utility productivity. Please explain how operating environment conditions impact the choice of technology.

A54. There are a number of operating environment issues that impact the technology set used by utilities. These might include local regulations related to pipeline maintenance, physical differences in inputs to deal with specific local operating conditions, different physical lives for assets based on local conditions, different types of inputs designed specifically for the customer mix served by the utility and so forth. These input issues cannot be addressed by using imputed input prices based on an index of general use thus resulting in measurement error related to the actual inputs used. Recognizing that TFP requires the change in physical outputs related to physical inputs, this is a significant source of error in the PEG estimates since the residual includes errors in measurement. While it is not possible to determine the magnitude of this error since it would vary from utility to utility, it nevertheless is further reason to place no reliance on the accuracy of the PEG TFP estimates.

This conclusion that TFP requires the change in physical outputs related to physical inputs has also been reached relative to developments of the academic model where Diewert et.al., conclude that "… operating environment factors beyond the control of the firm that may impact a group of regulated firms differently and affect their past and future productivity performance" (emphasis added)[28]. This is certainly the case for the diverse sample used by PEG but does not apply under the B&V analysis because each utility is treated independently thereby reflecting their own operating environment only.

Q55. Please explain the issues related to marginal cost based input and output prices.

A55. PEG relies on a competitive based model for estimating TFP and that requires that prices equal marginal cost for markets to be efficient and for firms to make decisions that are allocatively efficient. Technical efficiency, producing outputs at the lowest possible cost (also defined by the equation MC=min ATC) is essential to allocative efficiency which occurs when Price = MC = Min ATC. All of this assumes that firms are operating with the latest available technology and that output and input prices equal marginal cost. Under the academic paradigm, to the extent that input prices do not equal marginal cost a less than efficient combination of inputs will be used by the firm in producing outputs and to the extent that output prices do not equal marginal cost then a less than allocatively efficient level of output will be produced.

This is a particularly important issue for analyzing the efficiency of utilities since neither of these assumptions is true and the very reason for regulation is that the assumptions are not true. By

[28] The theory of network regulation in the presence of sunk costs, op. cit. p. 72

making these assumptions as part of a TFP analysis (a necessary condition to measure TFP among a cross section of firms, as PEG's approach does), the resulting TFP measure does not have any economic meaning on an evidentiary basis because the results do not match the actual performance of firms in the industry. Failure of these conditions to hold is one of the reasons that utilities use different technology sets and thus cannot be compared by the use of index numbers.

Q56. The PEG method implicitly assumes that the utility is operating at a point of constant returns to scale. Please explain why utilities do not operate at a point of constant returns to scale.

A56. As discussed above, the utility never operates at a point of constant returns to scale unless it is operating in long-run equilibrium where all scale economies are exhausted. From a practical perspective some parties in rate proceedings may argue that economies of scale do not exist any longer. This argument is wrong because it is based on a misunderstanding of the concept. In general the argument is that as a utility grows its cost rise and therefore there are no scale economies. The obvious answer to this claim is that economies of scale are defined based on fixed input prices and fixed technology. Observed changes in prices result from input prices, changes in technology and economies of scale.

I have previously demonstrated the nature of the economies of scale as they apply to gas main (the largest rate base item for distribution utilities)[29]. These economies of scale persist over all of the gas LDCs in either the PEG or B&V samples and we include the largest gas LDCs in the United States. Thus PEG's assumption of constant returns to scale cannot be correct based on evidence. This also means that the PEG indexing method cannot be used to measure productivity. When critical assumptions are not satisfied, the academic paradigm cannot be shown to produce meaningful results. Essentially the conditions for the proof that the results are valid fails leaving the analyst no ability to verify that the results are sound based on the underlying theoretical derivation of the model.

A similar conclusion results for electric utilities when one looks at specific inputs such as transformers, conductor, poles and even substations. Table 5 below illustrates the scale economies associated with electric transformers based on the actual installed cost for some typically sized overhead transformers.

Table 5

Cost per kVa of Transformer Capacity

Single Phase Transformer	Installed Cost	Cost per kVa
10 kVa	$1038	$103.80
15 kVa	$1034	$68.93
25 kVa	$1244	$49.76
50 kVa	$1725	$34.50

[29] This is the subject of my paper "Fixed Costs: An Inconvenient Truth" American Gas, June 2007,Appendix A p. 18

Q57. PEG assumes that because the regulatory process is designed to equate costs and revenues that there is no economic profit (dollars in excess of the actual costs of the return to equity). Please explain the assumption that utilities earn zero economic profit.

A57. This assumption is a condition of long-run competitive market equilibrium. It becomes a necessary condition for assuming constant returns to scale and also to assume cost minimization or output maximization. Under the modern regulatory paradigm this assumption is the equivalent of assuming that there are no economic profits for a utility. That is equivalent to assuming that the utility earns no more and no less than the opportunity cost of capital. The opportunity cost of capital is a market based concept related to the full economic return of and on the capital invested.

As a general matter, there is no guarantee that any utility earns even its allowed return on equity and certainly no guarantee that the allowed return is equal to the market return. As discussed above, the cost of capital is determined administratively and that becomes part of the decision calculus for investment in capital and for the decisions related to choosing optimal combinations of other inputs. It is not the allowed return that matters to investors who supply the capital it is the earned return and how that compares with the opportunity cost of capital in the market and that cost is unrelated to the embedded cost of debt as used in the PEG analysis. Further, to promote the development of efficiency investments, the cost of capital may need to exceed the market cost simply by virtue of the risk profile of efficiency investments. Assuming that utilities earn zero economic profit results in a different economic choice among inputs that may well not be on the production possibilities curve particularly where there are higher risks for new technologies. Solving the efficiency investment problem is one of the benefits of a properly designed PBR Plan as we have noted in IR responses.

Q58. PEG consistently uses a basic equation in testimony to explain the theory of TFP. Please explain the implications of Equation 6 in the PEG testimony.

A58. Equation 6 is based on a competitive market model where the long-run trend in costs will equal the long-run trend in revenue. This occurs in the competitive model because all firms operate as price takers and therefore choose to produce the level of output consistent with minimum average costs otherwise the firm will fail and exit the market. This assumption implies the following equality: LRAC= SRATC= SRMC=LRMC and the only point where this equality exists is the point of minimum LRAC= minimum SRATC and this point assures that all scale economies are exhausted and that the firms operate with constant returns to scale. This is just another example of PEG relying on an incorrect specification of the operating model for utilities rather than dealing with the more complex model of actual utility production and costs.

I am not the first analyst to recognize the fallacy in the PEG analysis. Rather, PEG has continued to use a model that has no meaning in spite of evidence to the contrary. In a 2009 proceeding Economic Insights reaches the following conclusion regarding the nature of the competitive model applied to regulated utilities:

> Much of the PEG (2009a, b) analysis is inappropriate because it attempts to treat energy distribution as if it were a competitive industry. The PEG analysis does not recognize the increasing returns to scale nature of the industry and the presence of sunk costs which means the 'indexing logic' PEG attempts to use is inappropriate. It is precisely because of these features that the industry is being regulated. Simply assuming that the industry should satisfy all the standard competitive properties, as PEG does, is neither appropriate nor useful.[30]

The PEG model continues to make these competitive market assumptions as noted in both Dr. Lowry's text and his footnote related to the discussion of Equation 6. The basis for these assumptions in competitive models is sound as demonstrated by elegant mathematical proofs for measuring TFP in competitive markets. No such proofs apply for regulated markets because the evidence is that the conditions of competition do not apply under regulation of monopoly energy suppliers. Further, it is also impossible for the analysis to rely on contestable market theory for the distribution and transmission functions as demonstrated by the continued regulation of these sectors under competitive unbundling models without policies that assure the markets are contestable.

Q59. Do you have further comments on the issues related to assuming Trend in Costs equals Trend in Revenues implicit in Equation 6?

A59. This is a basic equation for the competitive model. In that model costs are market based because prices are assumed to be established by the market and it is assumed that revenues result from producers' marginal costs times the quantity sold. Focusing initially on the cost side of the equation it is necessary to assume that the accounting depreciation is equal to economic depreciation, that the utility earns the allowed return, that the allowed return equals the market cost of capital (the marginal cost of capital in the current period) and that the utility operates technically and allocatively efficient. Without these assumptions the competitive model identity between cost and revenue is a meaningless concept. For example, if utility straight line depreciation is based on the physical life of the assets (the normal assumption for accounting depreciation) then the revenues derived from the regulated price cannot equal the actual costs. They may equal the accounting cost but that is not the assumption underlying costs and revenues as they relate to the economics of production that relies on the economic definition of costs.

A similar point may be made for the other assumptions discussed above. That is, the process of regulation is based on accounting costs not economic costs so any measure that relies on these concepts fails the underlying principles of economics. It is particularly important to note that the assumption of allocative and technical efficiency do not occur under regulation as I have discussed above. Sunk costs and lumpy capital investments along with physical depreciation

[30] "Electricity Distribution Industry Productivity Analysis: 1996–2008", Denis Lawrence, Erwin Diewert, John Fallon and John Kain, p. v.

assure that no utility ever has the most technically efficient set of productive inputs. It also means that the estimate of the technology set from even a large sample of utility data cannot be derived for any individual utility and the best that can be actually observed is how each utility moves toward the technically efficient productive set over time given the impact of the administratively determined price of capital and the prices faced for other inputs in their own markets.

It is even unlikely that the price for labor in every market is based on a competitive labor market because the utility labor quality requirements may be in short supply in particular markets. This is of particular concern for both gas and electric utilities related to a number of the skilled craft positions because of the need to replace the aging workforce. It also means that based on the size and sophistication of the utility some technologies may not be economically practical for every utility. Allocative efficiency requires that the prices for all inputs be based on marginal costs, a competitive market assumption. Any number of factors distorts input prices such as regulation, unionization, market shortages and so forth. The end result is that with sunk costs the most that could be expected as a test of efficiency is that the utility would minimize short-run variable costs and even there the existence of planning risks and long-term efficiency would likely result in variable costs that may be higher than expected if the utility only had to plan for the current output level in a one period market model. As soon as the utility must plan in a multi-period model it may well mean that a utility hires some inputs in advance of actual need so that those inputs can be productive in the next period as the result of being trained in the previous period.

Q60. Please comment on PEG's use of the employment cost index as the price of labor for determining the labor input.

A60. There are several basic problems associated with the use of the ECI as a measure of the price of labor. First, the index is not representative of the price of labor because it only represents the salaries and wages of the labor force. Based on data from the Bureau of Labor Statistics wages and salaries represent only about 70 percent of the total compensation for utility employees. When analyzing the economics of capital and labor substitution, utilities use the total compensation of labor. More importantly, the total compensation of labor is the value used by utilities to make decisions relative to efficient production of outputs. Careful review of the ECI data for utilities also calls into question the use of this index as a price to determine the required labor inputs for an investor owned gas and electric distribution and transmission companies just based on the definition used for the utilities sector and the data collected. The following is the official definition of utilities from the Bureau of Labor Statistics:

> The Utilities sector comprises establishments engaged in the provision of the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Within this sector, the specific activities associated with the utility services provided vary by utility: electric power includes generation, transmission, and distribution; natural gas includes distribution; steam supply includes provision and/or

> distribution; water supply includes treatment and distribution; and sewage removal includes collection, treatment, and disposal of waste through sewer systems and sewage treatment facilities.

This definition is troubling in several regards. First it includes the salaries and wages for generation plant operators including the operation of nuclear power plants. Second, it includes utilities such as water and sewer utilities both of which are predominately publically owned utilities with inherently different compensation structures and costs. Importantly, it is unrealistic to assume, as PEG does, that any adjustment to a particular utility's wage costs based on an adjustment between the national average ECI and a regional average that covers a number of states and thus cannot reflect the local markets for a particular utility. This means that the labor input for the local utility cannot possibly be an accurate measure where geography would indicate different wage rates based on local economic conditions. This is just another example of the inherent shortcomings of measuring physical inputs by dividing costs for a specific utility by a broader regional index. It should also be noted that the salary and wage index is not based on the total employment for a utility but only a segment that includes craft employees and the first line of supervision with no mention of other employees that work and support the craft employees. Third, the ECI is a fixed based index using 1975 as the base year and the weights are fixed. As discussed above a chain weighted index would be more appropriate and even that would not solve the fundamental problem of different mixes of employees.

The combination of using an inapplicable labor price and limiting it to only a portion of labor costs to calculate the physical labor input is just another example of how the academic paradigm assumes away the sticky real world problems in an effort to have an expedient if flawed result. Finally, as a practical matter based on data from the Bureau of Labor Statistics, the partial factor labor productivity in both gas and electric during the period 2002 through 2011 is only a small positive value on average over the period as we previously indicated as being the likely case. This suggests that the TFP should appropriately reflect the much larger influence of capital on TFP for utilities and confirms that a positive TFP value does not pass the test of basic logic in the face of infrastructure replacement as discussed above.

Q61. Is there any reason to believe that the index PEG uses to determine the inputs associated with materials, rents and supplies and labor provides a reasonable basis for measuring the other inputs associated with O&M and A&G expenses?

A61. No. The index that PEG uses is a weighted value that reflects both labor prices (with the problems noted above) and an index designed to reflect materials, rents and supplies. PEG has filed no evidence related to the index as it is a proprietary service. Nevertheless, having done a significant number of cost of service studies, I am familiar with the residual accounts that make up the materials, rents and supplies and these include a variety of accounts that have multiple components. For example, the account outside services includes any number of utility activities that differ from one utility to the next. It would be unreasonable to think that a single index could adequately address the various combinations of activities recorded in this account. Thus it is likely that the measure of inputs results in inconsistent measures for the same reasons that apply to the other price indices discussed above. That is the index used for converting dollars of costs to units of inputs cannot possibly reflect the differences that are included in these accounts for each utility. If the index cannot properly measure inputs as in this case there is no basis for concluding that the TFP estimate is reliable.

<u>Section Six- Measures of Inflation</u>

Q62. Is there any reason to change the measures of inflation from those proposed by the Companies?

A62. No. The key issue as noted above is to choose a combination of an I-Factor and an X-Factor that work together to provide a reasonable opportunity to earn the allowed return. There have been successful PBR Plans for both FEI and FBC based on the values of the CPI index. That index has a readily available set of independent forecasts for the future year as required by the plan. There is no reason to change this precedent.

Q63. Is it reasonable to use the EUCPI for both gas and electric capital costs as PEG has suggested?

A63. No. It is a basic requirement that the inflation measure reflect, in a reasonable way, the nature of the costs that will be changing. The EUCPI is driven by a set of inputs namely materials and equipment, labor and finance costs. These are weighted based on the results of electric construction projects. The major components for utility construction include poles and conductors as the largest component of the costs in distribution and transmission. The transformers in transmission substations are made of electrical steel, copper and cellulose. Conductors are made of copper and aluminum and some aluminum conductor is reinforced by steel. The major components of the gas system are steel and plastic pipe for mains and services. The EUCPI has no measure for the cost of plastic which is the most common pipe installed. Further the gas LDC does not use electrical steel, copper or wood that is used heavily in electrical construction. The basic equipment used in electric construction and in gas construction differs as well particularly for overhead electric construction. Even the skills of the labor force differ for electric and gas. The EUCPI cannot reasonably be used for gas construction because it fundamentally represents a different market basket of goods with different prices and weights.

Q64. Are there practical limitations to using the EUCPI?

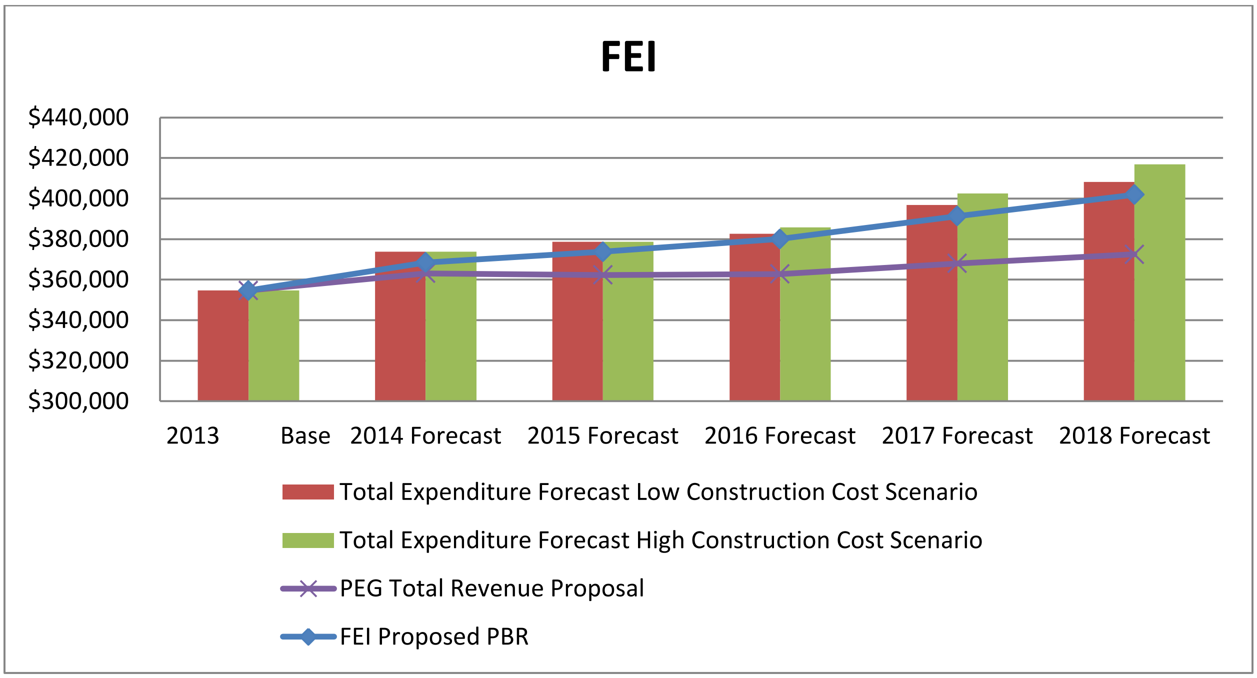
A64. Yes. The EUCPI is an after the fact calculation with no forecast of year to year values. For this reason alone there is no way to use the value in the forecast of revenue requirements required under the PBR Plan. Dr. Lowry acknowledges that this is the case without concluding that it makes the recommendation inoperable.

Q65. Does application of the PEG formula produce a pattern of O&M costs and capital expenditures over the regulatory control period that fails to provide FEI and FBC of a reasonable opportunity to earn the allowed return?

A65. Yes. At my request the Companies modeled the impact of the PEG recommendation as contained in the BCUC IRs based on the total revenue scenario. Since there is no forecast of the GDPPIPI FDD BC, the analysis assumed that the annual change would be the same as in the average of the most recent five year period. All other factors follow the PEG recommendation in BCUC IR 1.22.1 Total Revenue. Figure 4 below replicates the chart filed in the initial submission for FEI and adds the PEG recommendation to the chart.

Figure 4

Comparison of the Forecast FEI Costs to the FEI and PEG I-X Formulas

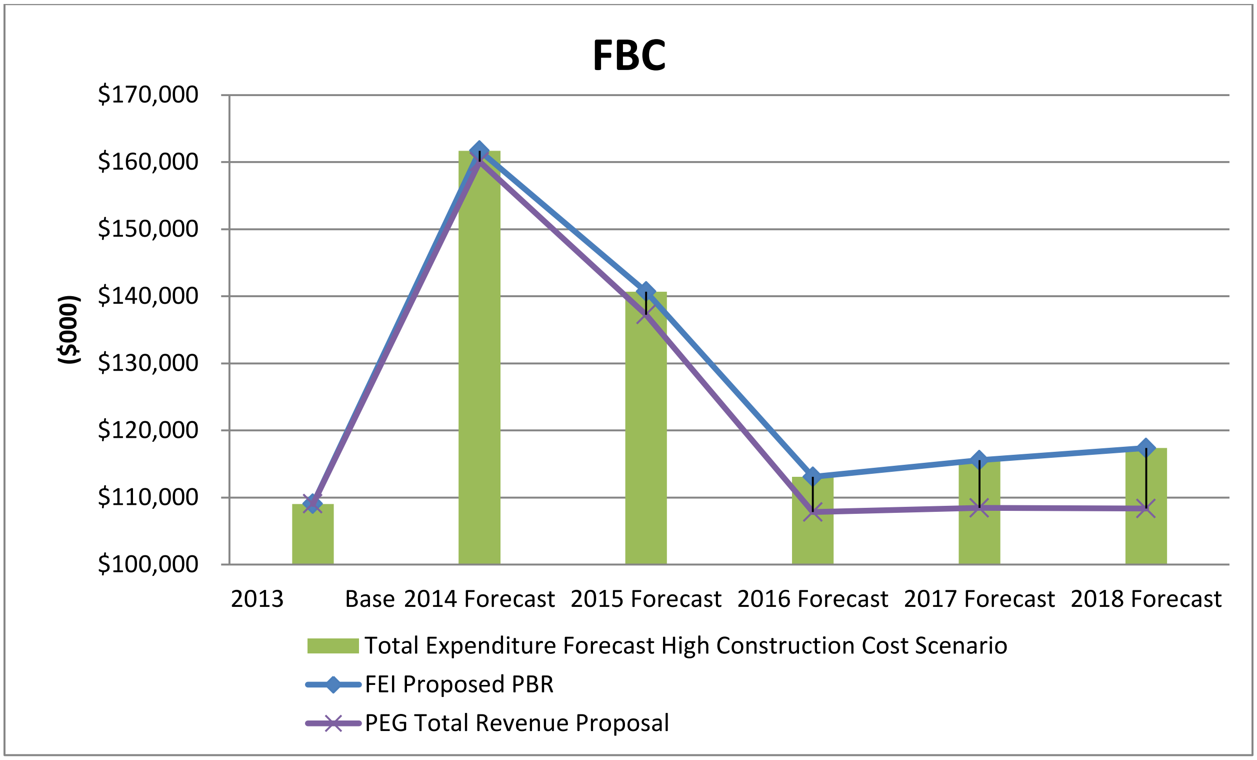


As the chart illustrates, the PEG expenditures that would be allowed under its proposal are far below those allowed under the FEI proposal. This means that FEI would be required to find far higher savings over the period despite the significant magnitude of savings achieved in prior PBRs. In particular, the PEG formula would require over 4.5 times the savings as the FEI proposal because the PEG model under the low forecast for construction costs reduces total expenditures by $112 million over the period.

A similar result occurs for FBC where the PEG expenditures are far below those under the FBC proposal. Figure 5 below replicates the chart filed in the initial submission for FBC and adds the PEG recommendation to the chart.

Figure 5

Comparison of the Forecast FBC Costs to the FBC and PEG I-X Formulas



As the chart illustrates, the PEG expenditures that would be allowed under its proposal are far below those allowed under the FBC proposal. This means that FBC would be required to find far higher savings over the period despite the significant magnitude of savings achieved in prior PBRs. In particular, the PEG formula would require almost 4.5 times the savings as the FBC proposal because the PEG model reduces total expenditures by $34 million over the period.

Q66. Please comment on the compound annual growth rate for O&M expenses over the period.

A66. The PEG formula results in a compound annual growth rate of O&M expenses over the entire period of about 0.5% for FEI and a negative 1% for FBC. This is totally inconsistent with results that might be reasonably expected if we just look at the wage component of the utility costs at 55 percent of the annual costs and use the underlying wage forecast (AWE) for BC. The increase in wages alone exceeds the PEG growth rate for O&M expense.

<u>Section Seven- PEG Errors of Omission</u>

Q67. Please explain the errors of omission in the PEG study.

A67. As noted above the PEG methodology tends to be relatively consistent over time. That is not to say however that PEG reaches the same conclusions and follows the same calculation methods in every filing. The decisions about what steps to include in the calculations tend to be almost random and thus there are large differences in the results based on whether the study follows one set of steps or another. In this case PEG omitted certain basic adjustments typically used in other work based on the input price differential and the productivity differential that PEG explains in detail in the Report at pages 13 and 14.

Q68. Is there a specific example of the types of calculations that may or may not appear in the actual PEG TFP calculations?

A68. Yes. The formulas included in the PEG report as 14, 15 and 16 have been included in the PEG analysis since Dr. Lowry testified with me in 1998, albeit in a slightly different form since the subject in that case was a price cap formula rather than a revenue cap formula and Dr. Lowry used the term TFP instead of MFP. Nevertheless, the issue remains the same that the use of an input price differential and a productivity differential is appropriate when using a macroeconomic measure of inflation.

Q69. Is PEG consistent in its treatment of these equations in the calculation of the TFP value?

A69. No. There is a fundamental disconnect between the text and the discussion of appropriate calibration and the actual TFP recommendations. PEG chooses to ignore the significance of these equations and despite making these adjustments in other regulatory filings fails to do so in this case. As a result of this inconsistent treatment there are three errors in the estimates of TFP beyond all of those discussed above as follows:

1) Recommends X-Factors that are both inappropriately high and inconsistent with his own theoretical reasoning;

2) Ignores an integral component of his own theory and methodology related to X-Factor calibration, relying on incomplete information as a result in producing his final X-Factor recommendations; and

3) Demonstrates inconsistency in the application of his own theory by not calibrating the X-Factor in this proceeding, but calibrating the X-factor in other proceedings when representing distribution utilities.

The analysis provided below will highlight these theoretical inconsistencies between PEG's recommendation and its own theory and supporting equations. The analysis will also show that when PEG's own methodology is applied appropriately according to the evidence filed, the resulting X-Factor recommendation are significantly lower than that proposed by FBC and FEI and are more consistent with the B&V recommendation of a zero X-Factor.

Q70. Please discuss the impact of the input price differential and the productivity differential as it applies to the TFP estimates made by PEG.

A70. The PEG testimony discusses these issues in several places and additionally has supported the adjustment of TFP estimates using one or both of these factors. In Dr. Lowry's 1998 testimony the TFP was adjusted for a productivity differential but not for the input price differential input price differential based on a statistical analysis of the differences in prices testing the hypothesis that the costs were different between the United States and the region. The decision not to include that differential was based on the inability to reject the hypothesis that the costs were not different. No such test has been performed in this case and there is no discussion of the rationale for not including either of the differentials despite the testimony concluding in at least one case that the differential is warranted. For example, the PEG report at page 53 states the following:

> Where a macroeconomic price index to be used as the sole inflation measure in any of the Automatic Rate Mechanism [PEG's term for the (I-X) Mechanism], the question arises as to whether X should be adjusted to reflect the productivity trend of the Canadian economy. The trend in the MFP index for the Canadian private business sector was close to zero over the last twenty years but modestly negative in the last ten years. US utilities routinely ask for, and have on several occasions received, X factor reductions when the MFP trend of the economy is positive. It is unclear what sectors of the Canadian economy contribute to the MFP decline. It is possible that the negativity is chiefly due to resource extraction industries that export a sizable percentage of their output. <u>Absent convincing evidence to the contrary, however, there is an argument for a modest positive X factor adjustment</u>. (Emphasis added)

PEG reaches this conclusion but does not act on this recommendation. Further, PEG does not make the necessary adjustment related to the input price differential. The end result is that an integral component of PEG's theory and formula actually suggests that a negative X-Factor adjustment is warranted if a macroeconomic inflation measure is used as we demonstrate below.

Q71. Please summarize the positions that PEG takes with respect to the input price and productivity differentials associated with a macroeconomic measure of inflation.

A71. PEG states that "when a macroeconomic inflation measure is used, the ARM [Attrition Relief Mechanism] must be calibrated in a special way if it is to reflect industry cost trends… [and that] … the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth" (p,13). For clarity, the 'index logic' to which PEG is referring is the 'revenue per customer index' and 'GDPPI' is the example of a macroeconomic inflation indicator used. This conclusion is consistent with prior testimony including the 1998 testimony with me.

According to the theory that PEG is employing, calibration of the X-factor depends on the relationship between a 'productivity differential' and an 'input price differential', each of which exert upward and/or downward pressure on the X-Factor depending on certain conditions. The summation of these two differentials determines the appropriate X-Factor that is warranted when a macroeconomic inflation measure is used. As such, both differentials need to be considered in light of one another in order to appropriately conclude whether an argument for a positive or negative adjustment of the X-factor exists.

The Productivity Differential is essentially a comparison of the productivity trend of the economy and the productivity trend of the industry. In particular, the differential is calculated as the difference between the Multi-Factored Productivity (MFP) trends of the Industry (comprised of the sampled Gas Distributors in the study and calculated by PEG) and the MFP trends of the Economy. The logic in the theory suggests that a positive or negative differential indicates the upwards or downwards calibration of the X-factor that is warranted. This point is reinforced by PEG on page 14 of its evidence:

"The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend embodied in the GDPPI."

Q72. Is the data available to calculate the values for these adjustments?

A72. Yes. In the PEG report and subsequent IR responses, PEG indicated that the MFP trend for the Canadian economy over the last 10 years was -0.45, while the MFP trend of the Industry (comprised of the sampled Gas Distributors) under PEG's Total Revenue scenario for Gas Distributors was 1.13. As such, the Productivity Differential under this scenario equals positive 1.58. This appears to be the basis for PEG's recommendation that there is an argument for a modest positive X factor adjustment. However, its recommendation does not take into consideration an integral component of the equation that it espouses: the Input Price Differential, which would also exert directional pressure on the X-factor.

Whereas the Productivity Differential compares the productivity trend of the economy and the industry, the Input Price Differential compares the input price trend of the economy to the input price trend of industry. In particular, the differential is calculated as the difference between the input price trend of the economy and the input price trends of the industry (comprised of the sampled Gas Distributors in the study). Again, the logic in PEG's theory suggests that a positive or negative differential indicates the upwards or downwards calibration of the X-factor that is warranted. This point is also reinforced by PEG on page 14 of its report:

> "The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price of the economy is more (less) rapid than that of the industry."

The methodology to calculate the input price differential of the economy is implicit in PEG's formula [15]: trend GDPPI = trend Input Prices-Economy – trend MFP-Economy. Using this formula, simple arithmetic indicates that the input price trend of the economy is simply the summation of the trend in the macroeconomic inflation measure used and the trend in MFP for the economy. In PEG's equation, GDPPI is used as the macroeconomic inflation measure. Rearranging PEG's formula [15] results in the following equation:

trend Input Prices-Economy = trend GDPPI + trend MFP-Economy

In its report, PEG indicated that the MFP trend for the Canadian economy over the last 10 years was -0.45. Table 7 of the report indicates that the Canada-GDPIPIFDD had an average growth rate from 2003 to 2012 of 1.87%. As such, the calculated implicit price index for the trend in input price for the Canadian Economy according to Dr. Lowry's methodology is 1.42% over the last ten years.

In Table 3 of the report, PEG provides the input price trend of the sample Gas Distributors, indicating an average annual growth of 3.16% from 1999 to 2011. When this is deducted from the calculated Input Price trend of the Canadian economy derived above (1.42%), we arrive at an Input Price Differential of negative 1.74. This differential suggests that an overall negative X factor adjustment is warranted in conjunction with a macroeconomic measure of inflation.

A quick comparison of the Productivity Differential of 1.58% and the Input Price Differential of -1.74% indicates that the downward calibration of the X-Factor suggested by the Input Price Differential more than offsets the upward calibration of the X-factor suggested by the Productivity Differential. As such, there is a clear argument for a negative X factor adjustment according to PEG's evidence and to the methodology used previously by PEG. This is particularly problematic given PEG's recommendation to the contrary and highlights a fundamental disconnect between PEG's own theoretical rationale for X-Factor calibration and PEG's recommendations in this proceeding. Further the analysis provided below will show that appropriate application of PEG's own theory regarding X-Factor calibration results in far lower X-Factors than those proposed by PEG as we show below.

Q73. Did PEG address the rationale for excluding these adjustments in its report?

A73. No. PEG only belatedly addressed the issue in its response to BCUC IR 1.5.3. In that response, PEG provides its rationale for making neither adjustment and unlike previous proceedings does so without a sound evidentiary basis relying rather on some generalized statements as follows:

1. Dr. Lowry's formula [15], $growth\ GDPPI = growth\ Input\ Prices_{Economy} - growth\ MFP_{Economy}$, is true only in the long run.
2. The MFP growth of Canada's economy has been modestly negative in the last 10 years, but closer to zero over longer time frames such as 20 years. Accordingly, the trend in input prices may not be accurately measured by the formula over a period of 10 years.
3. The negative MFP growth of the Canadian economy is due chiefly to the mineral extraction industry, where it has been driven in part by the progressively greater exploitation of high-cost reserves.[2] It is not clear how much impact this has on growth in the CPI or $GDPPI_{FDD}$.
4. The Commission is, in any event, likely to choose a macroeconomic inflation measure for BC and not for the Canadian economy.
5. Available data do not permit us to "complete the job" by accurately calculating the companion input price differential itemized in Dr. Lowry's formula [16].

These reasons are not internally consistent and cannot be used to avoid the fact that correcting for the input and productivity differentials produces negative TFP results. PEG is being internally inconsistent when it comes to what constitutes the long-run. Both of the first two reasons provided in late filed response to BCUC IR1.5.3 (mislabeled as IR 1.5.1 answered previously) seems to imply that a 10-year timeframe does not constitute 'the long run' and for that reason, PEG's formula [15] required for X-Factor calibration does not apply. This however is inconsistent with the PEG report, which concludes that 10-years is a sufficient timeframe for indicating long-run trends. The simple fact is that the TFP values calculated by PEG with all of their flaws as noted above would ultimately support a lower TFP than that proposed by FEI and FBC.

With respect to the third reason, PEG appears to be implying that significant influence of the mineral extraction industry and its impact on the CPI and GDPPIFDD provides justifications for not proposing the calibration of the X-Factor. The impact of the mineral extraction industry on the Canadian economy, growth CPI and growth GDPPIFDD is irrelevant with respect to X-Factor calibration. Both CPI and GDPPIFDD are economy-wide, output-based measures that reflect the change in the prices of the basket of goods for the economy in general. The impact of all industries should be reflected in these output-based measures, including mineral extraction if that is contributing to the economy as a whole. Certainly, the employees, vendors and investors create aggregate demand for outputs in the Canadian economy where they live and work. This point seems to provide a basis for the need to calibrate the X-Factor when a macroeconomic inflation measure is used to ensure that the PBR formula is indicative of input price inflation likely to be experienced by the utility industry in particular during the plan term. In addition, the demand for inputs for mineral extraction puts upward pressure on some of the same types of labor and equipment used by utilities. This is actually a reason to make the adjustments as PEG has done elsewhere.

With respect to the fourth reason, the presumption that the Commission is likely to choose a macroeconomic inflation measure for BC and not for the Canadian economy is not theoretical grounds to determine that X-Factor calibration is unnecessary. Moreover, PEG is being internally inconsistent in not recommending an adjustment to the X-Factor. PEG has indicated that it is theoretically unsound to not adjust the X-Factor when an output-based macroeconomic inflation measure is used in the PBR formula. Recommending either BC-GDPPIPIFDD or Canada-GDPIPIFDD results in using an output-based measure that already incorporate the effects of economy-wide productivity gains. Therefore, these output-based measures would not necessarily be indicative of the input price inflation likely to be experienced by the industry when used in the PBR formula. For that reason, X-Factor calibration is necessary whenever a macroeconomic inflation measures is used. PEG reinforces this point in its report, stating on page 13:

> "When a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends… [and that] … the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth"

Regarding the fifth reason, FBC and FEI believe PEG's evidence provides sufficient data to calculate the 'companion input price differential' itemized in PEG's formula [16]. The 'companion input price differential' referred to in that reason refers to the Input Price Trend of the Economy and the Input Price Trend of the Industry. Both the formulae and the data required to make the adjustments are provided in the data filed in the PEG Report and in IR responses related thereto.

Q74. Please explain how the input price and productivity differentials may be calculated from the data already filed in the case.

A74. For reference, formula [16] from the PEG report is provided below:

$$growth\ Revenue/Customer = growth\ GDPPI - \begin{bmatrix} \left(trend\ MFP^{Industry} - trend\ MFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + Stretch \end{bmatrix} \qquad [16]$$

The methodology to calculate the input price trend of the economy is implicit in equation [15] provided by in the PEG report:

$$trend\ GDPPI = trend\ Input\ Prices^{Economy} - trend\ MFP^{Economy}. \qquad [15]$$

By rearranging formula [15] we can determine that the input price trend of the economy is calculated as the summation of the trend in the macroeconomic inflation measure used and the trend in MFP for the economy, as expressed in the following equation:

trend Input Prices-Economy = trend GDPPI + trend MFP-Economy

According to PEG's report, the MFP trend for the Canadian economy over the last 10 years was -0.45. Table 7 of the report indicates that the Canada-GDPIPIFDD had an average growth rate from 2003 to 2012 of 1.87%, and the BC-GDPIPFDD had an average growth rate of 1.76%

over the same period. By applying these inputs into PEG's rearranged formula we can compute the input price trend of the Canadian economy to be 1.42% over the last ten years if using Canada-GDPIPIFDD, and 1.31% if using the BC-GDPIPIFDD.

With respect to the input price trend of the Industry, PEG provides this in Table 3 of the report. PEG indicates that the input price trend of the sample Gas Distributors from 1999 to 2011 is 3.15%.

If the equations and data provided by PEG are assumed to be sound, this analysis demonstrates that the available data does allow for the accurate calculation of the "companion Input Price differentials" required to "complete the job". Furthermore, analysis provided below will show that when the job is completed, the appropriately calibrated X-Factor is far lower than the PEG recommendation.

PEG's final recommendation against any specific adjustments to the X-Factor should the Commission choose to use any macroeconomic inflation measure is problematic and inconsistent in light of his own theoretical reasoning and logic. On page 14 of his evidence, Dr. Lowry provides the following condition that determines the necessity of X-Factor calibration when a macroeconomic inflation measure is used:

> "X-Factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy."

The analysis above indicates that both the input price and productivity trend of the utility industry as provided by PEG differ from those of the economy. Based on PEG's own logic analysis and prior testimony, the X-Factor should be calibrated. Analysis provided below will show that calibrating the X-Factor results in X-Factors that are far lower than those recommended by PEG.

Q75. Is there other evidence beyond your 1998 experience to indicate that PEG has made these types of adjustments?

A75. Yes. PEG's recommendation against adjusting the X-Factor in this proceeding is also the polar opposite of what he has advocated in other proceedings. For example, in 2007 PEG represented Central Maine Power Company (CMP) and provided direct testimony for its ARP 2008 Productivity Offset Factor that utilized the same methodology, as that provided in this report but not calculated, to calculate an X-Factor for CMP. In CMP's study, PEG calculated a Total Factor Productivity for the industry of 1.57% from 1993 to 2005. However, PEG's final X-Factor recommendation was 0.44% because the X-Factor was calibrated consistent with the methodology discussed above. In other words, unlike his present evidence filed in this proceeding, he properly applied his own theory in calibrating the X-Factor for CMP by considering the relationship between the Productivity Differential and Input Price Differential. The available data for CMP for growth in input price and productivity spanned a period of 12 years from 1993 to 2005. The available data provided in the PEG report in this case also spanned a period of 12 years. If PEG had employed the same reasoning against calibrating the X-Factor for CMP as he has now outlined in his evidence before this Commission, he would have recommended an X-Factor for CMP in line with what he is now proposed for FEI and FBC, which is simply the TFP growth of the industry. For CMP, that would have been 1.57%.

Q76. Does PEG make the adjustments to calibrate the final TFP recommendations in response to BCUC IR 1.22.1?

A76. No. Despite all of the testimony concerning this issue and having made these adjustments in the past, PEG makes no such adjustment in these final recommendations.

Q77. Please explain how the results of applying these adjustments change the TFP factors resulting in substantially lower X-Factors.

A77. From equation 16 we can see the combination of values required to implement the productivity differential and the input price differential.

$$\text{growth Revenue/Customer} = \text{growth GDPPI} - \begin{bmatrix} \left(\text{trend } MFP^{Industry} - \text{trend } MFP^{Economy}\right) \\ + \left(\text{trend Input Prices}^{Economy} - \text{trend Input Prices}^{Industry}\right) + \text{Stretch} \end{bmatrix} \qquad [16]$$

The term in brackets must be calculated to produce the appropriate X-Factor under the PEG methodology. The assumption underlying these calculations is that the PEG calculations are useful for determining the X-Factor even though we have shown that the PEG estimates cannot pass even a basic evidentiary test. Nevertheless, for consistencies sake we have simply corrected the PEG calculations.

PEG provides a separate recommendation based on either the capital revenue approach or the total revenue approach. The following summarizes the results using the PEG capital revenue approach.

<u>Gas</u>

From PEG's report and IR responses, we are able to extrapolate the following inputs required for the formula above:

Table 6

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	**– 0.45%**[31]	**1.34%**[32]	**0.20%**[33]
Growth BC-GDPIPI^{FDD}	1.76%[34]		
Trend Input Price	**1.31%**[35]	**3.16%**[36]	

Applying these inputs into PEG's X-Factor calibration formula we obtain the following:

$$\begin{aligned}\mathbf{GrRevPerCust} &\\ = \mathbf{BC - GDPPIFDD_{Growth}} - \Big[&\big(\mathbf{1.34}_{\boldsymbol{trend\ MFP\ Ind.}} - (\mathbf{-0.45}_{\boldsymbol{trend\ MFP\ Econ}})\big) \\ &+ (\mathbf{1.31}_{\boldsymbol{trend\ IP\ Econ}} - \mathbf{3.16}_{\boldsymbol{trend\ IP\ Ind.}}) + (\mathbf{0.20}_{\boldsymbol{Stretch\ Factor}})\Big]\end{aligned}$$

$$= \mathbf{BC - GDPPIFDD_{Growth}} - [\mathbf{0.14}_{\mathbf{Calibrated\ X-Factor}}]$$

As the PEG formula and theory indicates, when TFP growth of the industry for capital is 1.34% and the BC-GDPIPI is used as the sole macroeconomic inflation measure, a calibrated X-Factor of 0.14% including stretch ensures that the X is reflective of industry costs. This is in stark contrast to PEG's recommendation of 1.54% in this scenario, which results from inappropriately ignoring an integral component of its own theory and formulae and being inconsistent with prior testimony.

<u>Electric</u>

From PEG's evidence, we are able to extrapolate the following inputs required for the formula above:

Table 7

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	**– 0.45%**[37]	**1.05%**[38]	**0.20%**[39]
Growth BC-GDPIPI^{FDD}	1.76%[40]		
Trend Input Price	**1.31%**[41]	**3.13%**[42]	

31 PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
32 Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
33 Ibid. p.70
34 BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
35 Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]
36 Input Price Trend of U.S. Gas Distributors (1999-2011) from Table 3, Section 3 PEG Evidence
37 PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
38 Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
39 Dr. Lowry Evidence, Exhibit FEI C1-9 and FBC C6-9, p.70
40 BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
41 Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]

Applying these inputs into PEG's X-Factor calibration formula we obtain the following:

$$\mathbf{GrRevPerCust} = \mathbf{BC - GDPPIFDD_{Growth}} - \left[\left(\mathbf{1.05}_{\boldsymbol{trend\ MFP\ Ind.}} - \left(\mathbf{-0.45}_{\boldsymbol{trend\ MFP\ Econ}}\right)\right) + \left(\mathbf{1.31}_{\boldsymbol{trend\ IP\ Econ}} - \mathbf{3.13}_{\boldsymbol{trend\ IP\ Ind.}}\right) + \left(\mathbf{0.20}_{\boldsymbol{Stretch\ Factor}}\right)\right]$$

$$= \mathbf{BC - GDPPIFDD_{Growth}} - \left[\mathbf{-0.12}_{\mathbf{Calibrated\ X-Factor}}\right]$$

As PEG's formula and theory indicates, when TFP growth of the industry for capital is 1.05% and the BC-GDPIPI is used as the sole macroeconomic inflation measure, a calibrated X-Factor of -0.12% ensures that the X is reflective of industry costs. This is in stark contrast to PEG's recommendation of 1.25% in this scenario, which results from inappropriately ignoring an integral component its own theory and formulae and being inconsistent with prior testimony.

Q78. Please explain how the adjustments for the input price differential and the productivity differential alter the PEG recommendations under the total revenue approach.

A78. PEG's X-Factor recommendation associated with the Total Revenue scenario is inappropriate and theoretically inconsistent with its own theory. By recommending the use of BC-GDPIPIFDD without calibrating the X, PEG violates its own theoretical logic related to X-Factor calibration as noted above. Appropriately applying PEG's X-Factor calibration formula in the manner described above results in significantly lower X-Factors that are appropriate to ensure that the PBR formula is reflective of industry costs. The assumption underlying these calculations is that the PEG calculations are useful for determining the X-Factor even though we have shown that the PEG estimates cannot pass even a basic evidentiary test. Nevertheless, for consistencies sake we have simply corrected the PEG calculations.

<u>Gas</u>

From PEG's evidence, we are able to extrapolate the following inputs required for the formula above:

[42] Input Price Trend of Sampled Power Distributors (2002-2011) from Table 6, Section 3 PEG Evidence

Table 8

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	**– 0.45%**[43]	**1.13%**[44]	**0.20%**[45]
Growth BC-GDPIPI^{FDD}	1.76%[46]		
Trend Input Price	**1.31%**[47]	**3.16%**[48]	

Applying these inputs into PEG's X-Factor calibration formula we obtain the following:

$$\mathbf{GrRevPerCust} = \mathbf{BC - GDPPIFDD_{Growth}} - \left[(\mathbf{1.13}_{\boldsymbol{trend\ MFP\ Ind.}} - (\mathbf{-0.45}_{\boldsymbol{trend\ MFP\ Econ}})) + (\mathbf{1.31}_{\boldsymbol{trend\ IP\ Econ}} - \mathbf{3.16}_{\boldsymbol{trend\ IP\ Ind.}}) + (\mathbf{0.20}_{\boldsymbol{Stretch\ Factor}})\right]$$

$$= \mathbf{BC - GDPPIFDD_{Growth}} - [\mathbf{-0.07}_{\mathbf{Calibrated\ X-Factor}}]$$

As PEG's formula and theory indicates, when TFP growth of the industry is 1.13% and the BC-GDPIPI is used as the sole macroeconomic inflation measure, a calibrated X-Factor of -0.07% ensures that the X is reflective of industry costs. This contrasts with PEG's recommendation of 1.33% in this scenario, which PEG reaches by inappropriately ignoring an integral component of its own theory and formulae and being inconsistent with prior testimony.

Electric

From PEG's evidence, we are able to extrapolate the following inputs required for the formula above:

Table 9

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	**– 0.45%**[49]	**1.18%**[50]	**0.20%**[51]
Growth BC-GDPIPI^{FDD}	1.76%[52]		
Trend Input Price	**1.31%**[53]	**3.13%**[54]	

[43] PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
[44] Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
[45] Ibid. p.70
[46] BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
[47] Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]
[48] Input Price Trend of U.S. Gas Distributors (1999-2011) from Table 3, Section 3 PEG Evidence
[49] PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
[50] Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
[51] Ibid. p.70
[52] BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
[53] Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]
[54] Input Price Trend of Sampled Power Distributors (2002-2011) from Table 6, Section 3 PEG Evidence

Applying these inputs into PEG's X-Factor calibration formula we obtain the following:

$$\mathbf{GrRevPerCust} = \mathbf{BC - GDPPIFDD_{Growth}} - \left[(\mathbf{1.18}_{\boldsymbol{trend\ MFP\ Ind.}} - (\mathbf{-0.45}_{\boldsymbol{trend\ MFP\ Econ}})) + (\mathbf{1.31}_{\boldsymbol{trend\ IP\ Econ}} - \mathbf{3.13}_{\boldsymbol{trend\ IP\ Ind.}}) + (\mathbf{0.20}_{\boldsymbol{Stretch\ Factor}}) \right]$$

$$= \mathbf{BC - GDPPIFDD_{Growth}} - [\mathbf{0.01}_{\mathbf{Calibrated\ X-Factor}}]$$

As PEG's formula and theory indicates, when TFP growth of the industry is 1.18% and the BC-GDPIPI is used as the sole macroeconomic inflation measure, a calibrated X-Factor of 0.01% ensures that the X is reflective of industry costs. This contrasts with PEG's recommendation of 1.38% in this scenario, which it reaches by inappropriately ignoring an integral component of its own theory and formulae and being inconsistent with prior testimony.

Q79. Please summarize the results of correcting the PEG recommendations for the inflation and productivity differentials as PEG has done elsewhere and even supported in the report in this case but did not calculate.

A79. If the PEG report had followed its own recommendations and applied its theory correctly to adjust for the input price differential and the productivity differential as explained in the report which are necessary to calibrate the X-Factor properly (assuming that the PEG methodology were valid) the recommended X-Factors would be as follows:

Table 10

Corrected X-Factor Calculations

	Gas		Electric	
Scenario	**PEG Recommended X-Factor**	**Appropriately Calibrated X-Factor**	**PEG Recommended X-Factor**	**Appropriately Calibrated X-Factor**
Capital Revenue	1.54	0.14	1.25	-0.12
Total Revenue	1.33	-0.07	1.38	0.01

Since these values include the recommended stretch factor as part of the calculation, they are well below the FEI and FBC recommendation of a 0.5 value for the X-Factor and are in fact closer to the B&V recommended zero X-Factor. In any event, the PEG Report, even with all its real world problems that essentially render the X-Factor useless does not produce evidence that would suggest any X-Factor other than the value recommended initially by the Companies.

<u>Section Eight- PEG Criticisms of the B&V TFP Calculations</u>

Q80. Please comment on the general nature of the criticisms PEG makes of the B&V Studies.

A80. Generally speaking the criticisms and the corrections basically amount to PEG's view that their method is the only correct method for calculating TFP. In other words, if the assumptions and the academic paradigm is not used the results cannot be valid. Since we have demonstrated by evidence that the PEG results are not valid this criticism is not well founded. PEG would impose the same failed indexing methodology on the B&V results.

Q81. How has B&V dealt with this issue in estimating TFP?

A81. B&V has not estimated TFP using an index based methodology. Rather, B&V correctly recognized that each utility has its own unique production function as the result of past decisions related to sunk costs, lumpy capital additions, regulatory determined cost of capital and operating environment. Under these conditions, it is necessary to look at each utility individually and to measure the changes in productivity for the industry based on a large sample of utilities by averaging productivity estimates from each individual company's data across the sample. It is a more robust measure, albeit not perfect, than a measure that requires numerous assumptions that cannot be met. The important point is that the method is adapted to real world conditions not theoretically derived from a myriad of assumptions that cannot be justified based on the evidence available in a regulatory hearing.

Q82. When you say the method is not perfect what does that mean?

A82. That means the estimates are not as precise as might be obtained if there was more data available to assist in the estimating process and in retrospect if B&V had modified some of its process to be more precise such as using the wealth of information about pipe by size and type to reflect the different technologies. As discussed below better data would improve the precision of the estimates but is unlikely to be practical since the requirements would be substantially more costly as standardized reporting requirements and would be of minimal value except as it relates to developing measures of productivity.

For example, infrastructure replacement raises costs but because of retirements the physical amount of pipe replaced cannot be determined and in some cases may actually be fewer miles of pipe to provide the same capacity. This would occur when the replacement of a low pressure cast iron system may be more economical by serving the new high pressure system from a closer point than was used by the older system. It also means that the percentage of larger diameter pipe declines as smaller diameter pipe operating at higher pressures replaces the low pressure system. Data is not reported in a way that allows one to measure the physical change in inputs and the concept of duality (using changes in cost divided by a suitable price index for those costs) does not provide a reasonable estimate of the change in inputs because of the wide variation of costs for things like the installation of main and service which are the two largest components of distribution plant. This is a practical issue because even within the service area of a single company the cost of installing main will vary widely. These variations reflect issues such as where the main is laid, the complexity of the installation, local regulations and so forth.

Figure 2 below is an example of complexity of installation associated with installing pipe in an urban environment.

Figure 2
Co-Location of Gas Pipe in an Urban Trench

In more densely populated areas customers tend to be served from electric conduit, cable conduit, water lines, unused steam lines and telephone conduit that are buried near or co-located with gas main. Figure 2 above illustrates this issue for an urban street. In Figure 2 the gas main is the green coated pipe. Further, the rules and regulations applicable to service in urban areas typically impose extra costs on the utility for excavation (often requiring hand digging and removal of all materials) and monitoring of repairs. It is also common that urban areas have strict requirements related to backfill and paving even beyond those imposed by Federal safety regulations and requirements that limit how and when work can be done to install, maintain, repair and replace distribution system components. As population density increases, it is typical for the safety-related requirements placed on operators of a natural gas distribution system to escalate as well.

The reasonable conclusion from this information is that annual cost changes may have little to do with how costs change on average and more to do with where the work is located as well as the volume of the work at each location. Importantly, this also illustrates why even within a utility production functions vary based on the makeup of the area being served. No price index, including the Handy-Whitman Index can adequately reflect these differences. As a result the concept of duality is of little use since the index is designed to remove the impact of inflation to measure real inputs and the real inputs change significantly because of factors unrelated to inflation. The PEG report assumes that by dividing the cost by a measure of inflation and then dividing by a price index is an adequate measure of real inputs. That assumption is wrong simply because it does not take into account the differing quality and quantity of inputs required by the utility based on factors beyond its control.

Q83. Are there other areas where B&V might have adjusted its model based on comments from PEG?

A83. Yes. B&V used the change in net plant (gross plant additions less annual depreciation expense) and did not adjust this value for inflation as recognized by PEG. This was not an arbitrary oversight as implied by PEG in their comments. Instead, B&V simply assumed that the net plant additions measured a change that was smaller than the impact of using gross plant additions adjusted for inflation. This point is easy to understand since net plant is well below the value of gross plant adjusted for inflation and thus was a conservative value. A simple example will illustrate this point. For the first gas LDC in our study - Alabama Gas (also used by PEG) the change in net plant from 2007 to 2008 is just over $13 million while the gross plant additions for 2008 are over $51 million. Thus the measure of capital additions is far below the actual input additions that would result from adjusting the $51 million for inflation under any reasonable estimate of inflation. The net result is our analysis is TFP is biased toward a TFP that is less favorable to the utilities as the result of using net plant without adjusting for inflation. B&V believed that this approach is reasonable despite the inherent bias because the bias is less favorable to the utilities.

With respect to O&M not being adjusted for inflation as recommended by PEG that impact would be insignificant in any event and we chose not to adjust O&M for inflation because of the difficulty in knowing what measure of inflation to use when a portion of the payroll adjustment also reflects a change in the quality of labor over time and other factors such as outsourcing of maintenance.

Overall the results of the B&V analysis are reasonably conservative and directionally correct without relying on many unsubstantiated assumptions as the PEG values do.

Q84. Are their examples of the PEG assumptions that are discussed as errors in the B&V studies?

A84. Yes. PEG states on page 59 that B&V included some costs that rose rapidly during the period including uncollectible accounts expense, pension and benefits costs and DSM expenditures. These are all assumptions made by PEG in their own study and PEG essentially finds fault based on their assumptions. The evidence provided in response to CEC IR2 PBR 61.2 and 61.4 with attachments is pertinent. For the gas DSM programs the aggregate cost increased over the period of the TFP study but that is largely explained by the increase in the number of programs offered as opposed to the cost of individual utilities. The facts contradict the assumptions made by PEG with respect to their list of errors.

In addition, PEG conveniently ignores the impact of various programs on uncollectible accounts expense. The following table shows that LIHEAP (Low Income Home Energy Assistance Program) funds increase dramatically over the period from 2007 through 2011 and that also served to reduce uncollectible accounts expense as well.

Table 11

Annual LIHEAP Program Funding

Year	Funding
2007	$2.16 billion
2008	$2.57 billion
2009	$5.1 billion
2010	$5.1 billion
2011	$4.7 billion

The end result is that PEG's claimed criticism is unfounded. Further, these costs are part of the overall cost of the utility and should be included in developing a TFP analysis.

Q85. Does the B&V report create a material bias in the estimate of TFP because it does not adjust for a measure of inflation as claimed by PEG?

A85. With respect to capital it does not because it uses net plant to measure capital inputs which is a conservative factor compared to gross plant adjusted for inflation. Further, it is net plant that drives the critical relationship to the ability of the I-X equation to match costs and revenues. As discussed above this was not an oversight but an effort to allow the methodology to reflect the real world level of inputs which the PEG model fails to do completely. Absent being able to develop an index to discount nominal dollars for each utility based on their own unique technology set and the unique capital input mix for each year there is no realistic way to avoid the problems created by the PEG methodology. Indeed, such an index would of necessity be a chained index because the capital input mix would change each year requiring the index to have different weights for each period and for each company in the sample. B&V believed that given the length of the period any impact or bias would be relatively minor and certainly not the three percent mentioned in the PEG report simply because the net plant measure is far below the gross plant reduced by three percent per year. This approach correctly recognizes that added capital adds to used and useful inputs in contrast to the PEG approach that removes used and useful plant from the calculation each year.

Q86. Is the PEG criticism of the short period used for the calculation of a TFP estimate valid?

A86. No. There is a sound reason to use a shorter period rather than a longer period. Simply, the shorter period is representative of the types of efficiency gains that might be reasonably expected during a five year plan. Further, the PEG concern about the recession's impact is totally misplaced simply because utility management has the responsibility to manage earnings to market expectations regardless of the macroeconomic circumstances. It would be reasonable to assume that if there was any impact of the recession and inflation during this period, utilities would have attempted to seize every efficiency opportunity that would be accretive to earnings in order to meet investor expectations or to minimize the shortfall from those expectations. Thus, from a managerial perspective there is no reason to believe that this creates a negative bias in TFP as it would more likely overstate the expected TFP for years in which growth occurs as utilities manage back to normal maintenance cycles and so forth. The shorter period also avoids a number of practical issues such as the impact of restructuring costs that are not properly included in a TFP study since the costs are not included in rates.

Q87. Is there a problem with using cost level indexes with numeraires that differ from utility to utility in the sample?

A87. No. Essentially, this is a concern only because the index method produces dimensionless measures of inputs and outputs so firms can be collected in the index. Since the B&V method treats each utility as its own entity because each utility has its own production technology set and its own input mix for all inputs this criticism is incorrect. This criticism would be correct for an index type measure because indexes use a dimensionless number that is calculated as the cost divided by a price index and is not really an actual measure of the input which has physical dimension such as miles of pipe or electric circuits. Since PEG is focused solely on a flawed index methodology PEG fails to recognize that the only values being used to calculate TFP are the percentages resulting from each utility measured only against itself. Those percentages are in fact dimensionless once they are developed. This is another example of the B&V method providing a more realistic estimate of TFP when compared to the theoretically and practically flawed method used by PEG.

Q88. Is there a reason that you did not use logarithms in the filing to calculate changes as suggested by PEG's criticism?

A88. Yes. It is important to communicate with all of the parties in a case. Using logarithms in an academic setting would not create an issue whereas many of the participants in a rate case are not trained economists and may be uncomfortable in the rigorous academic environment. Since regulation is about evidence and since there is no inherent need to use more complicated formulas, using differences seemed to be reasonable and has a basis in historic calculations of index values. As I have noted above, there was no claim that the results were expected to be accurate to three or four decimal places. Instead the results were used to benchmark the final X-Factor proposal relative to what might be expected in the real world. PEG missed this point and instead insists that PEG has a monopoly on the TFP methodology even though their approach is biased by their own arbitrary decisions of what to include in the index and what adjustments to make once the value falls out of their model. Further, their calculations of both inputs and outputs for the index are not correct and are beyond repair under an index model. As shown above, this results from assuming that a regional Handy Whitman Index can be used to deflate plant values to create a change in real capital dollars to be divided by a capital price index that bears no resemblance to the input basket for different utilities for more reasons than we have attempted to count.

Q89. Is it appropriate to treat depreciation expense as O&M as PEG has done when supposedly correcting the B&V approach?

A89. No. Depreciation expense is directly related to and part of the cost of capital. It is simply the return of capital and should be part of the capital cost component. This treatment is consistent with the fundamentals of revenue requirements where O&M is treated separately from the capital related components of taxes, depreciation and return.

Q90. Does it make sense to use the cost of capital that PEG uses to measure the change in revenue requirements for all utilities as PEG proposes in its corrections of the B&V method?

A90. No. As discussed in detail above, this is not a correct basis for measuring the cost of capital. This approach is only supported in theory for the competitive model. The cost of capital is one of the most vigorously debated elements of a utility rate filing and it differs from utility to utility based on any number of factors including the size of the capitalization, the capital structure, market and regulatory risk issues, and so forth. It is also true that depreciation cannot be the same for utilities because of a variety of factors not the least of which is how to treat asset groups or the physical life of various asset classes and there is no discussion of the correct depreciation for measuring TFP-economic depreciation. This brings the argument back to sunk costs and lumpy capital additions that cause no two utilities to use the same technology set or to have the same depreciation because of the input mix occurring over time.

Q91. Does PEG comment on various statements from your reports?

A91. Yes. PEG provides a section of its report beginning on page 66 titled “General Comments” where PEG comments on various statements in the B&V report with which they take exception. It is not necessary to address all of these statements here since some have already been discussed above. For example, we have proven that the service life of gas assets remains the same over its useful life and this conclusion has been reached by others as well. PEG essentially says that if this is true it has no importance for a TFP study because the TFP study is about cost and its impact on revenue requirements. Yet, PEG objects to a method of estimating TFP that ties directly to actual costs. TFP is not about costs but about explaining the relationship between physical inputs and outputs.

Further, PEG claims that capital productivity is positive based on their flawed measure of capital inputs. If the change in capital inputs is negative (as it is for numerous PEG data points) the TFP must be positive. Yet we have shown in every case that the physical inputs have increased not decreased as PEG has calculated. In simple terms this occurs despite adding new main and substation capacity, new services and replacing existing facilities. PEG is wrong in their comment related to the B&V on capital inputs.

Q92. Please address the issue of using volumetric measures of output in a TFP analysis discussed by PEG on page 67.

A92. PEG defends the use of a volumetric measure because it argues that it is a long-run cost driver. Although this is not a new argument (someone always tries to argue for a volumetric allocation of fixed costs as it shifts cost from lower load factor and smaller customers to larger and higher load factor customers), there is no reason to believe that the quantity of throughput changes system costs in the short-run or the long-run. Once the system has sufficient capacity to satisfy the various customer peaks (coincident peak, class non-coincident peak and individual customer non-coincident peak) there is no cost associated with increasing or decreasing volumetric measures of delivery for either gas or electricity. Volume is simply not an output of the delivery system and hence has no impact on the measurement of the change in outputs less the change in inputs. This means that any econometric work that includes a volumetric measure as an independent variable is flawed because there is no sound theoretical model that indicates that volume causes delivery costs as I have shown a number of times in cost of service testimony. This is the logical flaw that correlation is the same as causation. Finally, the most important reason that volume cannot be a measure of output is that it violates the assumption that the production function is non-decreasing in output or put another way it costs more to produce more output. A simple illustration will prove that volumetric measures violate this condition. Assume that a utility provides service to an identical service base with an identical set of peak demands in two periods without adding any new or replacement capital. The utility delivers K kilowatt-hours in period one and K+ 50,000 kWhs in period two. In a regulatory context, the unit costs would actually decline under the assumed hypothesis and this violates the non-decreasing assumption that underlies index methodology. Volumetric measures cannot be used even with price caps.

Q93. PEG concludes that the failings in the B&V study should be accorded no weight in the Commission's deliberations. Please comment on this conclusion.

A93. The numerous problems identified above completely invalidate PEG's preferred methodology. Even at an elementary level, PEG has treated inputs and outputs as homogeneous when they are heterogeneous as we have shown. This introduces bias. The data they have used is subject to measurement error as we have shown above. They have excluded an important measure of output - capacity - and that biases the results. They have not accounted for or even recognized that environmental differences (both physical and regulatory) impact TFP and leads to biased results. Index methodologies do not account for multi-period optimization or for risk management decision making. We have shown that PEG uses an incorrect deflator when they use the Handy Whitman Index and that results in incorrect quantity measures. That error is compounded by the use of an incorrect price measure resulting in further error in the measure of input quantity. Taken together all of these issues demonstrate PEG has not provided evidence or opinion that is meaningful or even valid for use in the current case. The B&V approach is consistent with industry circumstances and common sense and the recommendation of a zero X-Factor is not only reasonable but also consistent with the results of PEG's Ontario electric recommendation and the results of the flawed PEG approach when adjusted for factors PEG claims should be made.

<u>Section Nine- Economic Issues Associated with the Service Quality Index (SQIs)</u>

Q94. Have you reviewed the testimony of Ms. Alexander with respect to the issues of the Service Quality Index?

A94. Yes.

Q95. Please summarize your review of that testimony.

A95. My review is focused on regulatory principles and does not address individual recommendations in the report beyond those that have impact on the regulatory principles. As I will discuss below the proposals made by Ms. Alexander make certain assumptions and reach conclusions that are not valid and that cannot be implemented in any event because the proposals are deficient. The proposed treatment of SQIs in the FEI and FBC PBR Plan are consistent with successful past practices and satisfy proper regulatory oversight and evidentiary standards. In addition, the standards proposed by the Companies are consistent with the proposed revenue requirements whereas Ms. Alexander proposes increases in SQI measures that would raise the cost of providing the service but provides no recovery of those costs. Without cost recovery and adjusting revenue requirements, the proposed SQI standards automatically become confiscatory and thus violate the principle that utilities be allowed a reasonable opportunity to earn the allowed return.

Q96. Please discuss the assumption that Ms. Alexander makes regarding the proposed SQI standards.

A96. In proposing that an automatic adjustment must be made under the PBR Plan, Ms. Alexander implicitly assumes that there is no regulatory mechanism for the Commission to control service quality standards. This is not correct since the Commission always has the affirmative right to investigate service quality standards on its own motion. The difference is that investigating service quality is based on an evidentiary standard that Ms. Alexander's proposal seeks to bypass. Under her proposal, if the Companies fail to meet the standards she suggests, the penalty provision is automatic. Essentially, this means that Ms. Alexander assumes that any failure to meet a standard is the result of management's bad faith, management's negligence, mismanagement or imprudence. It is unacceptable regulatory practice to make such assumptions because each of these characteristics is subject to an evidentiary test. By accepting the reporting requirement proposed by the Companies, the Commission has the necessary information to determine if any regulatory action is needed but must do so through a hearing process that permits evidence related to the outcomes and no penalty may be assessed without a thorough examination of the factors that occurred because those factors may be beyond the reasonable control of management. In fact, customers may even be the cause of poor performance on reliability metrics or even customer service metrics. A simple example illustrates this point. Gas cannot be turned on when appliances are not in working order. If a furnace does not work properly, the customer is responsible for its maintenance and repair and service will not be turned on until it is safe to do so.

Q97. Please comment on using total retail revenue as the basis for a penalty.

A97. Total retail revenues include far more than any potential gain from deterioration in service quality. There is no rationale to tie performance to revenues that even includes gas and purchased power supply costs a utility must have an opportunity to recover all prudently incurred costs including a return of and on capital. If service deteriorates that would be accompanied by above allowed earnings (assuming that the deterioration was actually the result of the utility cutting costs and not for some reason beyond the control of the utility). The proposal to penalize the utility would deprive the utility of its opportunity to earn the allowed return without any test of the reasonableness of the utilities actions or a determination that events beyond the reasonable control of the utility impacted the measures. At most, the penalty should be tied to earnings (the potential gain from reducing service quality) above the allowed return and be based on some reasonable post assessment of the standards outcome.

Q98. Please comment on the compensation standards for failure to meet the targets as proposed by Ms. Alexander.

A98. The compensation standards are arbitrary ($50 and $250 thousand per percentage point below the target). Further the penalty provisions constitute asymmetric risk for the utility since there is no upside benefit. Even with an upside benefit the higher standards proposed have costs and Ms. Alexander has not recommended any additional base period costs to meet standards above those recommended by the Companies. Thus, there is no assurance that any reward for provision would compensate the Companies for providing a higher level of service.

Q99. Is Ms. Alexander correct that the SQI proposal shifts all of the service quality risk to customers?

A99. No. Customers already bear all the risk of SQI under cost of service regulation so this represents no change in the risk sharing if this is even a risk for customers. A number of requirements related to customer service are required by legislation, regulation and the approved Tariff. For example, the Gas Tariff spells out the provisions where the Company is responsible for service conditions (24.1 - Gross negligence or wilful misconduct) and provides that customers are responsible for facilities on their premise that impact service. Also, since Ms. Alexander recommends higher standards for some metrics without any proposal to include in rates the necessary costs to assure those standards imposes risk on the Companies and is contrary to the standards for just and reasonable rates. Finally, many of these so called risks are not risks at all but rather represent a level of ease or convenience. For example, having to wait more than thirty seconds for a non-emergency call is not a risk for the customer.

Q100. Is there any reason to believe current standards are inadequate?

A100. No. No evidence has been presented that the current customer service standards are inadequate. It is not costless to improve standards and unless the extra expenses of meeting higher standards (to the extent that the Company can control those events) are included in revenue requirements the Company will be penalized for standards that it is not compensated to meet to begin with. The issue of standards must reflect the balance between costs and benefits and recognize that the law of diminishing returns applies even to customer service, i.e. if it costs X dollars to answer 70% of all non-emergency calls in 30 seconds it may cost an additional X dollars just to get that number to 75%. In essence, regulation of performance by arbitrary SQIs (without knowledge of the costs and benefits and importantly the customers' willingness to pay higher rates for higher standards) is a flawed concept.

Q101. Does the Commission have tools to address issues related to service quality?

A101. Yes. All commissions have tools to address service quality on their own or to respond to a complaint. They also have tools to correct poor performance as well.

Q102. Is service quality solely a utility function?

A102. No. There are many aspects of service quality that are beyond the reasonable control of the utilities' management. By rejecting this fact, the proposal of the COPE witness lacks credibility related to actually understanding the numerous issues related to service quality. For example, service delays quite often occur based on other factors not under the direct control of the utility. An example might include faulty equipment that prevents gas service from being turned on until customer facilities are repaired. On the electric side, storm damage may impact customer owned facilities that must be repaired prior to re-establishing service. In both of these cases, the duration of the outage is the result of the customer's actions and cannot be controlled by the utility. There are also access issues that are beyond the control of the utility such as impassable roads or blocked access to the premise. Finally, for major events requiring outside crews to assist with restoration there may be travel delays and other timing issues to move the needed extra equipment in from outside the service territory.

Q103. Does this complete your testimony?

A103. My testimony is complete except for an addendum (Addendum 1) to be added to address the changes proposed by CEC in response to the second round of IRs.

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Table 11: AER conclusion on ActewAGL's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		15.2	17.0	18.8	20.5	22.3
Return on capital		52.6	57.1	61.1	65.0	68.2
Tax allowance		4.7	5.5	5.7	5.4	5.6
Operating expenditure		61.2	67.4	73.8	80.8	85.5
Annual revenue requirements		133.7	147.1	159.4	171.7	181.6
Energy sales (MWh)	2 906 274	2 932 862	2 916 011	2 907 581	2 898 320	2 888 942
Revenue yield (¢/kWh)	4.09	4.77	5.08	5.42	5.77	6.15
Expected revenues	118.9	139.9	148.2	157.5	167.3	177.8
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–13.82	–4.00	–4.00	–4.00	–4.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Final decision, Australian Capital Territory distribution determination, 2009–10 to 2013–14, 28 April 2009

Table 21: AER conclusion on Country Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		154.1	176.7	141.5	161.1	180.8
Return on capital		379.4	433.0	488.6	550.9	613.6
Tax allowance		43.9	46.5	39.2	45.6	50.1
Operating expenditure		405.4	424.0	442.8	461.2	477.9
TUOS adjustment		–44.9				
Annual revenue requirements		937.9	1080.2	1112.2	1218.9	1322.4
Expected revenues	732.3	856.8	1000.0	1153.0	1329.7	1370.4
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–13.41	–13.31	–12.00	–12.00	0.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Table 22: AER conclusion on EnergyAustralia's revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		76.0	99.5	120.1	142.3	138.4
Return on capital		640.9	740.7	852.6	977.6	1098.9
Tax allowance		31.5	58.4	66.5	75.5	78.9
Operating expenditure		483.1	506.4	530.8	554.6	570.6
Annual revenue requirements		1231.4	1404.9	1570.0	1750.1	1886.7
Expected revenues	1023.5	1224.3	1382.7	1562.7	1758.7	1924.6
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–17.86	–12.00	–12.00	–12.00	–8.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Table 23: AER conclusion on EnergyAustralia's revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.0	7.4	10.9	14.2	13.5
Return on capital		90.3	114.9	130.7	153.3	183.6
Tax allowance		2.6	6.2	7.2	8.5	9.2
Operating expenditure		35.9	36.5	37.3	38.3	38.5
Annual revenue requirements		132.8	165.0	186.2	214.4	244.7
Expected revenues	129.5	143.0	162.6	185.0	210.4	239.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–7.77	–11.00	–11.00	–11.00	–11.00

(a) Negative values for X indicate real revenue increases under the CPI–X formula.

Table 24: AER conclusion on Integral Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		144.3	123.2	119.7	113.4	106.1
Return on capital		326.0	366.5	413.9	456.4	495.8
Tax allowance		34.9	38.4	38.1	37.3	37.5
Operating expenditure		304.8	314.8	327.4	339.7	346.8
Annual revenue requirements		809.9	843.0	899.2	946.8	986.1
Expected revenues	652.8	749.9	828.4	919.0	984.8	1024.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–12.58	–7.00	–7.00	–2.00	0.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Final decision, New South Wales, distribution determination, 2009–10 to 2013–14, 28 April 2009

Table 37 AER conclusion on revenue requirements and X factors ($'m, nominal)—CitiPower

	2010	2011	2012	2013	2014	2015
Return on capital		121.0	132.3	143.5	156.3	168.9
Regulatory depreciation		34.7	38.4	42.3	46.5	51.8
Operating expenditure		46.3	47.6	50.1	50.8	53.3
Efficiency carryover amounts		4.5	–8.4	–6.2	–5.5	–
S factor amounts		–2.2	–4.7	–3.6	–0.4	–4.0
Tax allowance		6.3	6.7	7.4	7.7	8.4
Annual revenue requirements		210.6	211.8	233.5	255.4	278.5
Expected revenues	213.3	205.8	221.0	235.3	252.8	273.9
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		6.41	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 38 AER conclusion on revenue requirements and X factors ($'m, nominal)—Powercor

	2010	2011	2012	2013	2014	2015
Return on capital		208.0	227.7	247.1	267.2	288.8
Regulatory depreciation		62.1	69.9	77.9	86.3	96.8
Operating expenditure		160.9	167.8	169.9	179.3	188.2
Efficiency carryover amounts		–	1.2	–10.4	–14.5	–
S factor amounts		–6.1	–22.0	–5.6	–0.3	0.9
Tax allowance		12.5	12.9	14.1	15.0	16.4
Annual revenue requirements		437.4	457.4	492.9	532.9	591.1
Expected revenues	422.2	440.7	470.0	497.4	529.0	568.8
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–0.11	–3.00	–3.00	–3.50	–4.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 39 AER conclusion on revenue requirements and X factors ($'m, nominal)—JEN

	2010	2011	2012	2013	2014	2015
Return on capital		75.2	80.8	87.1	93.2	99.6
Regulatory depreciation		26.6	31.7	37.7	43.0	42.9
Operating expenditure		57.5	57.8	59.4	66.4	67.0
Efficiency carryover amounts		20.4	14.6	16.9	–0.7	–
S factor amounts		5.6	1.0	–0.2	–0.2	–11.1
Tax allowance		2.9	3.4	4.4	5.5	5.9
Annual revenue requirements		188.2	189.3	205.3	207.2	204.3
Expected revenues	168.8	179.8	190.1	199.3	209.1	220.8
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–4.99	–3.00	–3.00	–3.00	–3.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM.

Table 40 AER conclusion on revenue requirements and X factors ($'m, nominal)—SP AusNet

	2010	2011	2012	2013	2014	2015
Return on capital		200.2	219.9	244.6	270.0	295.7
Regulatory depreciation		91.1	51.2	62.3	58.1	55.1
Operating expenditure		162.9	174.2	184.9	199.2	207.1
Efficiency carryover amounts		11.4	–24.9	–9.3	2.0	–
S factor amounts		41.3	21.3	–7.6	–1.8	–89.6
Tax allowance		11.1	2.9	5.1	4.2	3.9
Annual revenue requirements		518.0	444.5	480.0	531.7	472.3
Expected revenues	373.9	430.0	458.4	488.4	528.1	575.0
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–9.99	–4.00	–4.00	–5.00	–5.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

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Table 41 AER conclusion on revenue requirements and X factors ($'m, nominal)—United Energy

	2010	2011	2012	2013	2014	2015
Return on capital		129.7	142.7	155.6	165.2	173.1
Regulatory depreciation		41.0	49.1	59.9	70.1	78.0
Operating expenditure		108.6	113.6	117.2	124.9	129.8
Efficiency carryover amounts		–	–	–	–	–
S factor amounts		–4.9	–5.1	–6.7	–6.8	–12.3
Tax allowance		8.5	8.8	9.8	11.7	13.5
Annual revenue requirements		282.9	309.2	335.8	365.0	382.1
Expected revenues	291.8	301.9	313.6	324.5	349.5	379.4
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–0.37	–1.00	–2.00	–6.00	–6.00

Note: Negative values for X indicate real price increases under the CPI–X formula.
Source: PTRM

Final decision, Victorian electricity distribution network service providers,

Distribution determination 2011–2015, October 2010

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC or the Companies)
Applications for Approval of
Multi-Year Performance Based Ratemaking Plans for
2014 through 2018

Addendum 1
to the Rebuttal Testimony of
Dr. H. Edwin Overcast, Black & Veatch

to Evidence of
Dr. Mark Lowry (CEC)

March 3, 2014

Q1. Have you reviewed the responses Dr. Lowry made to the second round of IRs?

A1. Yes, to the extent of the answers were actually filed. I would note that Dr. Lowry indicated that further responses would be filed in several business days so that portion of his responses could not be reviewed.

Q2. Please comment on the continually changing nature of Dr. Lowry's recommendations related to PBR.

A2. Since hearings are about evidence, it is difficult to focus on changing recommendations related to key elements of the plan. However, the basics of this case as they relate to the calculation of the X-Factor and the recommended measures of inflation continue to rely on analysis that is factually wrong. The PEG recommendations for the value of the X-Factor are unsupportable because the methodology can be shown to produce results that are meaningless as discussed in detail in the full rebuttal testimony. The use of the EUCPI has no relevance to gas construction and the recommendation cannot be supported. With respect to removing some capital from the calculation of TFP, even Dr. Lowry now admits that this is not a valid approach. (See the response to BCUC 2.4.3 and 2.13.1.) The net result of his recommendations does not solve the inapplicability of his results because it does not constitute factually based evidence but rather assumption based evidence where the assumptions are wrong.

Q3. Please discuss the recommendations for the use of a capital tracker.

A3. First, I note this is an entirely new recommendation and I have not had the opportunity to fully digest it. Nevertheless, it must be addressed in some form. Dr. Lowry claims that there should be standards for including CPCN costs in a tracker. Dr. Lowry suggests five standards as follows:

- Large (*i.e.* having a material effect on the company's finances)
- Non-revenue producing
- Not associated with unusually rapid O&M productivity growth that permit project self-financing.
- Not reflected in the productivity research on which the X factor is based
- Required by a government agency or other powerful external party

The suggested standards cannot be the basis of a reasonable review because they do not form a reasonable basis for assessing a project particularly in light of his conclusion that any one or more of these standards may justify tracker inclusion. CPCN projects meet the first standard because they are exclusively large projects but may not meet other standards. For example, the standard that such projects are not reflected in the productivity research cannot be satisfied for either the PEG sample or the B&V sample of utilities because the data is inclusive of all projects including CPCN-type projects. The issue of non-revenue producing is even more problematic. Infrastructure projects may be both revenue and non-revenue producing. This occurs when replacing the aging infrastructure also provides a capacity upgrade for new growth. It makes no sense to assume that such a project could not be included if it required a CPCN application.

The idea that O&M savings could result in a project being self-funded does not even have any meaning as it relates to gas main construction, for example. No utility spends more dollars on maintenance of a facility than the annual carrying charge rate for replacing that facility. Typically, savings on O&M from asset replacement would be a small fraction of the annual carrying cost of new facilities. So the recommendation that this be a standard does nothing but create a regulatory bonanza for other parties to raise an immaterial issue to delay or complicate the project review process needlessly. In short the CPCN process addresses projects that are required by the system (used and useful) and the ultimate inclusion in rate base reflects only prudent costs. These are the relevant standards and there is no need to add needless costs and complications to the process.

It is also worth noting that Dr. Lowry also provides a description of costs that should be passed through in response to BCUC 2.15.5. I would note that CPCN projects meet three of the four criteria listed. With respect to the utilities control over such projects, it is true that the utility has some level of control over project costs but that cost control is also subject to additional review prior to the inclusion of costs in rate base.

Q4. Is there a chance for double counting when treating CPCN costs outside the PBR Plan?

A4. No. There are adequate safeguards in place to assure that there is no double counting. These safeguards include annual and mid-term reviews, the strict limitation of only CPCN projects that receive approval passing through to costs outside the PBR and the potential for a prudence review before approval of the final addition of costs to rate base.

Q5. Is Dr. Lowry's concern related to the treatment of CPCN under cost of service methods appropriate?

A5. No. Even a PBR method must still meet the fundamental test that the utility have an opportunity to earn a return of and on assets that are used and useful and the costs prudently incurred. The CPCN process assures that these factors are satisfied and costs are passed through only to the extent that they meet the regulatory requirements for inclusion in rates.

Q6. Dr. Lowry recommends that the funds available for CAPEX be determined by escalating the cost of depreciation and return on the embedded capital by an I-X mechanism (BCUC.2.10.1) where the X-Factor is related to capital productivity, is this concept valid?

A6. No. The proposal fails to reflect the impact of income taxes resulting from tax depreciation and the added revenue requirement that increases toward the end of the life of the asset because the depreciation expense has been fully written off before the full return is earned. Second, the recommendation fails to recognize those capital dollars that are included each year to permit the older facilities to operate until the end of their useful life. Third, the capital formula proposed by the Companies only applies to incremental capital. Under its proposal the Companies flow through the impact of accumulated depreciation and lower capital costs for existing rate base continuously to customers. This effectively means that all of Dr. Lowry's comments related to negative attrition (the declining rate base for existing assets) are not an accurate reflection of the proposed PBR Plan. In any case, the recommendation is neither sound nor accurate. Dr. Lowry offers no evidence of any rationale for the capital tracker proposal and the separate treatment of CPCNs has been successful in past PBR Plans.