<u>OPG Interrogatory #1</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 General

a) Please provide the data set, TFP model, and any other quantitative analysis and models (e.g., regression analysis for the cost elasticities for generation capacity and volume as discussed on page 48 of PEG's report) used by PEG in its TFP analysis.

   Please provide all materials in "live" format, such as Microsoft Excel. Please make sure all formulas are intact and operable.

b) Please provide documentation to facilitate understanding of the materials and to link them to the discussion of results in PEG's report. Sufficient information should be provided on the design and working of the model, the data used, and the firms used in the data set for the analysis to enable another researcher to replicate the results of PEG's analysis.

<u>Response:</u>

The following response was provided by PEG:

a) Please see the attached working papers PEG-WP-1.xlsx, PEG-WP-2.xlsx, PEG-WP-3, and PEG-WP-4.zip. These contain data and formulas to support the calculations contained on tables 1-7 of the original report. The PEG-WP-1 file supports the US calculations, PEG-WP-2 supports variations on the LEI work and OPG/Ontario Hydro TFP calculations, PEG-WP-3 supports the econometric model presented on Table 7 and PEG-WP-4 provides miscellaneous items. The program code to do the econometric work is written in the R language which is freely available on the internet. Some tables have been added to the working papers or augmented to support other PEG interrogatory responses.

   Please note that the results reported in PEG's report were calculated using computer code. In addition to providing this code in its working papers, PEG has reproduced these results in Microsoft Excel in order to comply with OPG's request.

b) Documentation in the form of labeling and annotations is provided in both the code and the spreadsheets. PEG's report in Exhibit M2 also explains the calculations.

OPG Interrogatory #2

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 section 5

Please provide the results of PEG's study assuming one-hoss shay depreciation for the periods 1975-2014, 1996-2014, and 2003-2014.

Response:

The following response was provided by PEG:

PEG has not performed this task, which would involve several days of additional work. A one hoss shay treatment of capital cost was not undertaken in PEG's research for their report in Exhibit M2. OPG's request requires historical data that are not currently in PEG's databases. These data are only available in printed form, and this complicates their gathering and processing within the limited time available.

OPG Interrogatory #3

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 general

a) Please list and provide all studies of hydroelectric generation reviewed by PEG.
b) Please identify which of these studies use MW as an output and which use MWh.
c) Please identify which of these were used for regulatory purposes.

Response:

The following response was provided by PEG:

a-c) Table M2-11.1-OPG-3 below provides details of the studies that PEG reviewed. To the best of their knowledge, none of these studies were used for regulatory purposes.

Table M2-11.1OPG-3

Hydroelectric Generation Studies	**Outputs**	
	MWh	**MW**
Banfi, S., & Filippini, M. (2010). **Resource rent taxation and benchmarking – A new perspective for the Swiss hydropower sector.** *Energy Policy* , *38* (5), 2302-2308.	X	
Barros, C. P. (2008). **Efficiency analysis of hydroelectric generating plants: a case study for Portugal.** *Energy Economics* , *30* (1), 59-75.	X	
Barros, C. P., & Peypoch, N. (2007). **The determinants of cost efficiency of hydroelectric generating plants: A random frontier approach**. *Energy Policy* , *35* (9), 4463-4470.	X	X
Barros, C. P., Chen, Z., Managi, S., & Antunes, O. S. (2013). **Examining the cost efficiency of Chinese hydroelectric companies using a finite mixture model.** *Energy Economics* , *36* , 511-517.	X	X
Boucinha, J. M., Inácio, C. F., Gonçalves, A. C., & Gonçalves, A. V. (2015). **Measuring Efficiency of Portuguese Hydro Power Stations: DEA as a Tool for Internal Company Benchmarking.** *Coimbra Business Review, 1* (1), 66-73.[1]	X	
Briec, W., Peypoch, N., & Ratsimbanierana, H. (2011). **Productivity growth and biased technological change in hydroelectric dams.** *Energy Economics* , *33* (5), 853-858.	X	X
Filippini, M., & Luchsinger, C. (2007). **Economies of scale in the Swiss hydropower sector.** *Applied Economics Letters* , *14* (15), 1109-1113.	X	
Filippini, M., Geissmann, T., & Greene, W. H. (2016). **Persistent and Transient Cost Efficiency – An Application to the Swiss Hydropower Sector** (Economics Working Paper 16/251). Switzerland: Centre for Energy Policy and Economics at the Swiss Federal Institute of Technology Zurich.	X	
Jha, D. K., & Shrestha, R. (2006). **Measuring efficiency of hydropower plants in Nepal using data envelopment analysis.** *IEEE Transactions on Power Systems* , *21* (4), 1502-1511.[2]	X	
lo Storto, C., & Capano, B. (2014). **Productivity changes of the renewable energy installed capacity: an empirical study relating to 31 European countries between 2002 and 2011.** *Energy Education Science and Technology Part A: Energy Science and Research* , *32* (5), 3061-3072.	X	
Sarıca, K., & Or, I. (2007). **Efficiency assessment of Turkish power plants using data envelopment analysis.** *Energy* , *32* (8), 1484-1499.	X	
Sözen, A., Alp, İ., & Kilinc, C. (2012). **Efficiency assessment of the hydro-power plants in Turkey by using Data Envelopment Analysis.** *Renewable Energy* , *46* , 192-202.	X	
Wang, B., Nistor, I., Murty, T., & Wei, Y. M. (2014). **Efficiency assessment of hydroelectric power plants in Canada: A multi criteria decision making approach.** *Energy Economics* , *46* , 112-121.[3]	X	X
Whiteman, J. (1999). **The potential benefits of Hilmer and related reforms: Electricity supply.** *The Australian Economic Review* , *32* (1), 17-30.	X	

[1] MWh is considered an output variable in this study, though it is not retained in the final three models.

[2] Installed capacity is not used as an output variable in this study. However, winter and summer peaking capacity are used as outputs; these are both measured as maximum power output (in MW) during the system peak.

[3] This study employs the Technique for Order Preference by Similarity to Ideal Solution (TOPSIS) method. Outputs and inputs are not distinguished from each other (all are simply "indicators").

OPG Interrogatory #4

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 general

a) Please list and provide all other North American productivity research reviewed by PEG for its report in Exhibit M2.
b) Please identify which of the reports identified in part (a) were used for regulatory purposes.

Response:

The following response was provided by PEG:

a-b) PEG did not review any other productivity research in preparing its report in Exhibit M2. However, in the course of its work over time and in developing its expertise, PEG has reviewed numerous gas, electric, and telecommunications productivity studies. Most of these studies were prepared for regulatory purposes.

<u>OPG Interrogatory #5</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 Page 4

On page 4 PEG states that, "*Monetary approaches have to date been much more common in North American productivity research to calibrate X-factors.*"

Please provide all instances that PEG has identified where monetary approaches have been used to calibrate X-factors for rate setting of a generation related business.

<u>Response:</u>

The following response was provided by PEG:

PEG is unaware of any productivity studies prior to this proceeding which have been expressly prepared to calibrate X factors that would be applicable solely to power *generation*. However, productivity studies have been commissioned and filed by Niagara Mohawk Power, Central Maine Power, and the Hawaiian Electric companies which used a monetary approach to capital quantity measurement in proceedings to calibrate X factors applicable to *vertically integrated* electric operations.[1] The cost of generation was a large part of the cost addressed by the proposed rate or revenue cap index in these proceedings. All of these studies used a geometric decay specification.

Niagara Mohawk's proposal for an IRM was not implemented, and the company restructured its operations a few years later to admit retail competition. Central Maine Power agreed to a settlement that included an IRM that was informed by the X factor calibration research. The Hawaiian Electric companies' proposed IRM was never implemented. However, the MFP trend from the study was subsequently adopted as a productivity offset to a *labor* cost escalator in IRMs approved at a later date for the

[1] See studies filed in New York PSC Dockets 94-E-0098/94-E-0099/94-G-0100, Exhibits MNL-2, *A Summary of TFP Results,* and MNL-3, *Sources and Methods for the Niagara Mohawk TFP Study*, 1994; Maine PUC Docket 1992-00345, Lowry, M.N. and Thompson, H., *Productivity Offsets for Inflation-Cap Indexes: Basic Principles with an Application to Central Maine Power*, 1994; and Hawaii PUC Docket 99-0396, Lowry, M.N. and Hovde, D., *Price Cap Index Calibration for Hawaiian Electric Company*, 1999.

Hawaiian Electric companies.

PEG is also aware of two additional MFP studies filed by vertically electric integrated utilities ("VIEUs") that used a monetary approach to capital quantity measurement. The first was filed by Oklahoma Gas & Electric in a 1999 IRM initiative. The second study was filed by Kansas City Power & Light in 2006. It calculated MFP trends for VIEUs and their separate generation, transmission, distribution, and customer service functions. Both of these studies used geometric decay specifications. In addition to these studies, PEG has prepared several MFP studies for VIEUs which are not in the public domain.

In contrast, PEG is not aware of any instances where a utility has filed a VIEU productivity study featuring a non-monetary capital quantity treatment.

<u>OPG Interrogatory #6</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 page 5

On page 5 PEG states that *"Gradual asset decay matches the stylized facts of hydroelectric generation and is consistent with utility cost accounting."*

Please provide evidence that the assets of OPG or its peers in the hydroelectric generation sector exhibit the "gradual asset decay" to which PEG refers to in the reference above.

<u>Response:</u>

The following response was provided by PEG:

There are several kinds of evidence in the record of this proceeding already that suggest that gradual asset decay matches the stylized facts of hydroelectric generation. One is the rapid decline in O&M productivity that has typified companies managing aging hydroelectric generating stations. Another is the extensive hydroelectric generation plant additions that utilities have made after plants are constructed which do not increase their capacity. Some of these additions were likely used to maintain capacity and generation volumes or to extend the lives of assets. PEG does not believe that these additions were always matched by retirements.

It should also be noted that the monetary method captures the *efficiency* with which utilities make replacement and refurbishment capex whereas LEI's method does not. For example, if OPG hypothetically invested a billion dollars for a replacement or refurbishment project where 100 million would suffice there would be no impact on measured productivity using LEI's methodology. Under PEG's methodology, this hypothetical wasteful project would rightly result in poor productivity performance.

OPG Interrogatory #7

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 10

On page 10 PEG states the age of OPG's hydroelectric assets creates a *"steady stream of opportunities for OPG to repair, refurbish, and replace its facilities."*

Please describe the specific opportunities to which PEG refers to in the reference above.

Response:

The following response was provided by PEG:

As hydroelectric generation assets age, they require increased expenditures to keep them running safely and efficiently. Some must eventually be replaced. OPG discusses a series of such opportunities in its 2015 Annual Report. For example, on pg. 23:

> OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and controls. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Over the next three years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 35 MW. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures. Where economic and practical, OPG pursues opportunities to expand or redevelop its existing hydroelectric stations.

OPG also provides examples of such opportunities on pg. 24. These include major equipment overhauls and rehabilitation of four facilities, runner replacement and upgrade at one facility, and several additional efforts aimed at rehabilitation and refurbishment of generating equipment and dam and storage structures.

OPG Interrogatory #8

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 21

PEG lists three depreciation profiles used to establish the capital input quantity under the monetary method: geometric decay, one-hoss shay, and cost of service. Please identify all jurisdictions that calibrate utility X-factors using each type of depreciation profile.

Response:

The following response was provided by PEG:

PEG has several concerns with the way this question is posed. First, some regulators may consider more than one capital input methodology when calibrating X factors. For example, over the years the OEB has based X factors in IRMs for power distributors on studies using both the geometric decay and cost of service methodologies. For that reason, PEG believes that it is better to review capital input quantity methods underlying the calibration of X factors on a plan by plan basis rather than on a jurisdictional one.

Second, approved IRMs are often the outcome of settlements. In those instances, it is often the case that the resulting X factor was informed by one or more productivity studies but their influence is unclear. It is also possible that an X factor in a PBR plan that is outlined in a settlement may be informed by productivity studies involving more than one capital input quantity method. For example, the Enbridge Gas PBR settlement in 2008 defined X as a percentage of inflation rather than a specific number. The productivity studies presented in the proceeding relied on both the geometric decay and cost of service methods and it is not clear which method was more important.

Third, PEG does not have all of the productivity studies that were the basis of or informed every X factor that's been approved. This is especially true of earlier plans.

With these caveats, Attachment M2-11.1-OPG-8 is a table that details instances in which productivity studies for X factor calibration which were submitted in regulatory proceedings used monetary capital quantity treatments. Outcomes of these proceedings are briefly discussed.

Attachment M2-11.1-OPG-8

CAPITAL QUANTITY METHODS USED IN X FACTOR CALIBRATION STUDIES FOR COMPREHENSIVE INDEX-BASED ARMs OF ENERGY UTILITIES[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Capital Quantity Methods Featured
Bundled power service	Central Maine Power (I)	Maine	1995-1999	Price Cap	Settlement's X factor proposal informed by productivity study featuring a geometric decay approach to capital quantity
Gas distribution	Southern California Gas	California	1997-2002	Revenue Cap	Geometric decay
Gas distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	Geometric decay
Gas distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Geometric decay
Power distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Geometric decay
Power distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Geometric decay
Gas distribution	Union Gas	Ontario	2001-2003	Price Cap	MFP study featuring geometric decay capital quantity informed Board's decision
Power distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	Settlement's X factor proposal informed by productivity study featuring a one hoss shay approach to capital quantity
Gas distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	X factor calibrated using MFP study filed in a previous proceeding featuring a geometric decay capital quantity
Gas distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	Geometric decay
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	X factor informed by a review of other X factors, many of which were calibrated in MFP studies featuring geometric decay capital quantity
Power distribution	Nstar	Massachusetts	2006-2012	Price Cap	Settlement's X factor proposal was informed by a productivity study featuring a geometric decay approach to capital quantity
Gas distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	X factor calibrated using MFP study filed in a previous proceeding featuring a geometric decay capital quantity
Bundled power service	Pacificorp (II)	California	2007-2009, extended to 2010	Price Cap	BLS MFP study of electric, gas, and sanitary sector featuring a hyperbolic depreciation profile informed settlement X factor
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	X factor informed by a review of other MFP trends and X factors, many of which relied on geometric decay capital quantity indexes
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	Results from a productivity study featuring a cost of service approaches to capital quantity informed Commission's X factor determination
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	Settlement's X factor proposal was informed by productivity studies featuring geometric decay and cost of service approaches to capital quantity
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	Cost of service
Power Distribution	All Distributors	New Zealand	2010-2015	Price Cap	Productivity studies featuring both the geometric decay and physical asset approach informed the Commission's X factor decision
Power Distribution	ATCO Electric, EPCOR, FortisAlberta	Alberta	2013-2017	Price Cap	One hoss shay
Gas Distribution	All Distributors	Alberta	2013-2017	Revenue Cap	One hoss shay
Power Distribution	All Distributors except those who opt out	Ontario	2014-2018	Price Cap	Geometric decay
Bundled power service	FortisBC	British Columbia	2014-2019	Revenue Cap	Cost of service
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Cost of service

[1] Shaded plans are plans that are not currently in effect.

OPG Interrogatory #9

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 general

a) Please confirm that some statistics agencies, including the US Bureau of Labor Statistics, utilize a hyperbolic depreciation profile.

b) Is a hyperbolic depreciation profile more similar to a geometric decay or one-hoss shay?

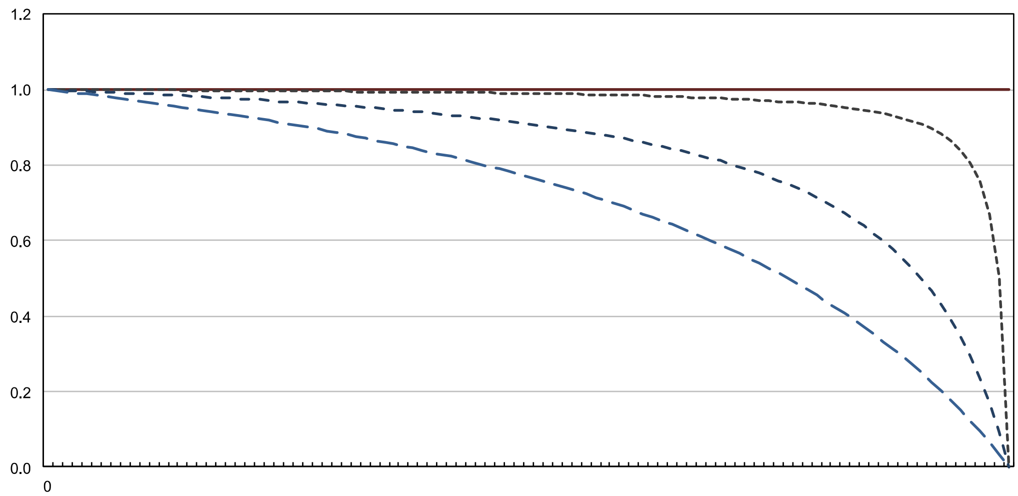
Response:

The following response was provided by PEG:

a) PEG confirms that the US Bureau of Labor Statistics assumes hyperbolic depreciation in its multifactor productivity studies.

b) The BLS uses a hyperbolic efficiency function of form $Q = (T-y)/(T-\beta y)$, where Q is the efficiency index, y is age, T is the service life, and β is a shape parameter. The efficiency profile produced by this function is sensitive to the value of the shape parameter. For $\beta = 1$, the function produces the one-hoss shay efficiency profile; for $0 < \beta < 1$, the efficiency profile is concave to the origin; for $\beta = 0$ it is linear decreasing; and for $\beta < 0$ it is convex to the origin. The effect on the efficiency profile of varying β between 0.7 and 1.0 is illustrated in the following figure.

Comparison of hyperbolic efficiency profiles under different values of β



In practice, BLS uses β values of 0.75 for structures and 0.50 for equipment.[1] This produces depreciation profiles that are convex with respect to the origin but quite different from one hoss shay. It is difficult to state whether the efficiency and depreciation profiles resulting from a value of β in the neighborhood of 0.65 (a sensible average of 0.75 and 0.50) is closer to those of one hoss shay or geometric decay.

The preceding comments are based on the assumption that an asset's service life is known with certainty. In the real world this may not be the case, or the quantity of interest may be that for a cohort of assets that are retired at different ages. It should be noted that treating the service life as a random variable produces a depreciation profile that is convex to the origin, even when the underlying efficiency profile is one-hoss shay. This effect is particularly pronounced when dissimilar assets are grouped together in a single cohort (since this tends to increase service life variability). The convexity of the depreciation profile is further enhanced when some or all of the underlying efficiency profiles deviate from one-hoss shay (e.g., hyperbolic, straight-line or geometric). Thus, even in cases where the efficiency profiles of individual assets do not themselves display geometric decay, the most appropriate profile may nevertheless be geometric.

[1] Bureau of Labor Statistics (1983). *Trends in Multifactor Productivity, 1948-81* (Bulletin 2178). U.S. Department of Labor, pg. 45.

<u>OPG Interrogatory #10</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 page 36

On page 36 PEG states LEI and many government studies of productivity are guided by the *"notion that the capital quantity index should measure the flow of services from capital assets."*

In PEG's understanding, what 'flow of services' does OPG deliver to ratepayers?

<u>Response:</u>

The following response was provided by PEG:

The flow of services that OPG provides includes generation volumes, capacity, and ancillary services.

OPG Interrogatory #11

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 11

a) Please confirm that under PEG's model, which uses monetary capital input and capacity output measures, a significant capital project such as the Niagara Tunnel Project would:
   i. cause higher input growth;
   ii. have no impact on output growth (as it does not increase capacity); and
b) cause a more negative MFP for the years when investment took place.
   If you are unable to confirm any of i) through iii) above, please provide an explanation.

Response:

The following response was provided by PEG:

a-b) PEG confirms that, using their methodology, the NTP would depress productivity growth in both the short and long run because it affects the generation volume of the SAB units but not their capacity. This is due to the fact that generation capacity was found to dominate generation volume as a cost driver in PEG's econometric work. PEG believes that the remarkably small impact that generation volume was found to have on the cost of hydroelectric generation in its study reflects the fact that the operation and maintenance expenses required to provide motive power for generators are lower than in nuclear, coal, or oil-fueled generation.

OPG Interrogatory #12

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 4

On page 4 PEG states *"a special smoothing technique may be needed to improve the estimate of the long-run productivity trend."*

a) Please specify the special smoothing technique(s) to which PEG is referring to in the above reference.

b) What circumstances necessitate the use of such a technique, and how effective is it?

Response:

The following response was provided by PEG:

a) PEG is referring to smoothing techniques like those which LEI used in its study. It was not referring to a specific smoothing technique.

b) Smoothing techniques can improve estimates of long run productivity trends when data used in productivity calculations are volatile. However, PEG believes that the smoothing technique LEI uses does not eliminate the effect of a decline in the volume/capacity ratio in LEI's study. Moreover, this decline is not clearly relevant to the situation of OPG.

OPG Interrogatory #13

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 46

On page 46 PEG states *"All utilities with hydroelectric generating plant exceeding $100 million in 2014 were considered."*

a) Please describe how PEG determined to use a $100M threshold.

b) Please confirm the relationship or level of correlation between the installed capacity and the generating plant value that was used as the threshold.

c) Please provide the underlying data that was used to determine the correlation in the previous sub-question.

d) Which companies were removed because of this threshold? Please provide the results of the study if there was no threshold. Please provide all the data and formulas intact for the MSP calculations.

Response:

The following response was provided by PEG:

a) PEG advised the OEB in its project proposal that a larger sample of utilities should be considered in a productivity study for OPG than LEI had considered. PEG chose the $100M threshold because it was a round value that would admit all the companies that LEI considered large and a modest number of additional companies. The $100M threshold was believed to strike a reasonable balance between the need for more data (in the form of more companies) and the need for relevant data.

b) Revised Table 2 in the working papers provides 2014 generation capacity as well as plant value for the companies in the PEG sample. No correlation exercise was undertaken.

c) Please see the response to part b) of this question.

d) 27 companies filed FERC Form 1s in 2014 which had hydroelectric generation capacity with a value below the $100 million threshold. These are identified in Table M2-11.1-OPG-13. PEG is not providing productivity results for an expanded sample that includes all of these companies. The preparation of such results would involve substantial additional work without greatly changing results. PEG did conduct runs prior to filing the report in Exhibit M2 which included 9 companies that did not meet the threshold. The result was an MFP trend of 0.46% for their featured 1996-2014 sample period. This was only 4 basis points lower than the result for $100M+ sample for the methodology in use at that time.

Table M2-11.1-OPG-13

Companies Below PEG's 100 Million Dollar Threshold

Companies	Gross Value of Hydroelectric Plant in Service 2014 (USD)
Louisville Gas and Electric Company	96,132,682
Alcoa Power Generating, Inc.	93,216,257
Upper Peninsula Power Company	86,869,661
Alaska Electric Light and Power Co.	84,988,705
Public Service Company of New Hampshire	70,225,535
Wisconsin Electric Power Company	67,340,888
Indiana Michigan Power Company	50,389,871
Wisconsin Public Service Corp	46,723,418
Wisconsin Power and Light Company	44,468,742
Jersey Central Power & Light Company	44,403,257
Entergy Arkansas, Inc.	42,369,920
Kentucky Utilities Company	39,468,869
Central Hudson Gas & Electric Corp	34,118,149
Northern Indiana Public Service Co.	32,302,505
Wisconsin River Power Company	31,355,677
Duke Energy Indiana, Inc.	30,632,758
Consolidated Water Power Company	29,549,469
Northern States Power Company - MN	25,352,641
Lockhart Power Company	19,647,879
Empire District Electric Company	9,442,340
Otter Tail Power Company	7,324,285
Narragansett Electric Company	3,126,435
MidAmerican Energy Company	2,309,568
Entergy Texas, Inc.	255,807
Northwestern Wisconsin Electric Co.	36,260
Bangor Hydro-Electric Company	36,078
Niagara Mohawk Power Corporation	8,220

<u>OPG Interrogatory #14</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 page 17

On page 17 PEG states *"Productivity growth is also affected by changes in the miscellaneous business conditions."*

Please provide specific examples of what would qualify as 'miscellaneous business conditions' in the context of hydroelectric generation business?

<u>Response:</u>

The following response was provided by PEG:

The business conditions that PEG refers to include any factor that affects productivity growth other than changes in technology, operating scale, X inefficiency, system age, or input prices. For example, regulatory changes pertaining to dam safety may increase costs. Productivity growth could also be affected by miscellaneous force majeure events such as an earthquake or terrorist attack.

OPG Interrogatory #15

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 26

On page 26 PEG states, *"[t]he productivity and volume/capacity trends of OPG should be monitored by the Board even if its data are not used to calibrate X."*

What in specific metrics does PEG recommend that the OEB monitor for, and what action does PEG recommend that the OEB take as a result of that monitoring?

Response:

The following response was provided by PEG:

PEG recommends that the OEB monitor 1) the ongoing trends in the Company's O&M, capital, and multifactor productivity of OPG and volume/capacity ratio. The former metrics can inform the Board's decision's on OPG's rebasings, X factors, and efficiency carryover mechanisms. The latter can be used to determine whether OPG's X factor should contain a volume/capacity (or, more generally, an output differential) adjustment.

OPG Interrogatory #16

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 section 5

PEG's study shows significantly different results between different time periods. On page 52 of Exhibit M2, PEG states that *"MFP growth of the sampled US utilities is considerably slower than in the past."*

Please explain PEG's understanding of the factors contributing to slow MFP growth in the recent period and specifically how business conditions contribute to these differences in reported results.

Response:

The following response was provided by PEG:

The slowdown in the MFP growth of hydroelectric generation reflects in part the reduction in economies of scale that could be realized after capacity growth slowed markedly. It also reflects the aging of hydroelectric assets. As plant ages, it's productivity growth is slowed since O&M and capital inputs are needed to maintain capacity.

OPG Interrogatory #17

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 page 64

"*Research by PEG in other proceedings has shown that utility productivity growth is substantially higher when a share of plant additions is removed from the calculations. If the CRVA is approved as proposed, an increase in the X factor is indicated which is commensurate with the excluded capex.*"

Please identify instances in which a regulator has increased the X-factor to reflect the approval of a capital tracker. Please specify the jurisdiction and case number, with reference to the specific decision.

Response:

The following response was provided by PEG:

It is commonplace for productivity studies used for X factor calibration to exclude costs that will be subject to tracker treatment and not addressed by indexing in an IRM. For example, such studies almost never include energy costs, and often exclude costs of demand-side management and pension and benefit expenses. The exclusion of costs that will not be addressed by indexing is consistent with the index logic detailed in Section 3.2 of PEG's report.

PEG is nonetheless unable to cite an instance where X factors have been adjusted to reflect the approval of a *capital* cost tracker specifically. It ventures the following explanations for this.

1. Many IR plans with index-based price (or revenue) cap indexes have not had trackers for the *normal* kinds of capex (e.g. capex for system growth or the replacement and refurbishment of aging assets) which are incurred by utilities in productivity studies. Trackers might instead address the cost of unusual capex such as that for advanced metering infrastructure.

2. When these provisions do coincide in an IR plan, the amount of normal capex tracked is usually uncertain, and specific kinds of capex are not dedicated for tracking. Thus, it is difficult to ascertain how much capex should be removed from the productivity study when calibrating the X factor.
3. Most jurisdictions where indexing and broad-based capital cost trackers coincide (e.g. Alberta, British Columbia, and Ontario) still have limited experience with these regulatory provisions and the regulatory community may not have not fully thought through appropriate policies to avoid overcompensation.

Energy Probe Interrogatory #1

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

The parties appear to agree that methods of statistical inference can be usefully applied in this case. For example, in its econometric cost analysis, the PEG report states:

> Results of the econometric work for the cost model are reported in Table 7. The table also reports the values of the *t* statistic that correspond to each parameter estimate. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the test statistic. (p.75)

Regarding its analysis of output quantity specification, the PEG report concludes that

> The estimated cost elasticities for the generation capacity and volume were 0.906 and 0.009, respectively. The parameter estimate for the volume variable was not statistically significant. (p.48)

Both PEG and LEI base their estimate of annual total factor productivity growth from samples of hydro generators over certain time periods. Figure 27 in LEI's expert report shows that the average TFP Index Growth for the years 2002-2003 to 2013-2014 was -1.01%. In response to Undertaking JT3.24 following the Technical Conference, LEI confirmed that the standard deviation of the annual TFP Growth rate in Figure 27 was 8.40% on a sample basis and 8.06% on a population basis.

Table 3 of the PEG report provides multifactor productivity ("MFP") growth rates for the years 1996-2014. For the 1996-2014 period, the mean annual MFP growth rate was 0.29% based on capacity and -2.03% based on volume. PEG did not provide the standard deviation for either estimate.

Table 3 of the PEG report also shows that MFP growth for the period 2003-2014 averaged 0.05% per year based on capacity and -1.83% based on volume. Again, PEG did not provide the standard deviations.

a) On page 48 of the PEG report, PEG reports that the parameter estimate for the volume variable was not statistically significant. Is this, as it appears, a regression-analysis result? Please provide the full estimated regression equation, the statistics typically calculated for the purpose of hypothesis-testing in a regression analysis, and the summary statistics typically calculated for the purpose of assessing the variance accounted for by the exogenous variables and the unexplained variance.

b) Please confirm/disconfirm that with a standard deviation of 8.4% in LEI's sample, the population mean, if it lies within one standard deviation would lie between -9.41% and 7.39%

c) To make the above more precise, please confirm/disconfirm that it is conventional in statistical inference (relying on the Central Limit Theorem) to characterize the sample mean as a normally-distributed random variable. Please additionally confirm/disconfirm that on LEI's data, the population mean inferred therefrom lies between -9.41% and 7.39% with a probability of 2/3.

d) Please calculate and confirm/disconfirm that the standard deviations for PEG's MFP growth rates (i.e. capacity and volume) for the 1996-2014 period are 1.71% and 13.56% respectively.

e) Please calculate and confirm/disconfirm that the standard deviations for PEG's MFP growth rates (i.e. capacity and volume) for the 2003-2014 period are 0.74% and 15.62% respectively.

f) The large standard deviation in LEI's sample of 8.4% suggests that the true population mean growth rate may not be statistically different from zero. Please perform the conventional one-sample statistical test of significance on LEI's sample data in Figure 27 of its report. Please use a 2-tailed test and a 5% significance criterion. Show all calculations and state the conclusion that PEG arrives at, along with any qualifying remarks that PEG feels are important.

g) Are PEG's mean annual MFP estimates for capacity and for volume for 1996-2014 and for 2003-2014 statistically significant? Please perform a 2-tailed test using a 5% significance level as was requested in the previous question e. Please show all calculations needed to compute the relevant test statistic and state the conclusion that PEG arrives at, along with any qualifying remarks that PEG feels are important.

Response:

The following response was provided by PEG:

a) Yes, this estimate was obtained econometrically and subjected to a standard statistical significance test. Please see Table 7 of the report for further details of the econometric work.

b) Confirmed.

c) It is confirmed that conventionally the sample mean is characterized as a normally-distributed random variable. Assuming all of the assumptions of the central limit theorem are satisfied, then the population mean inferred from LEI's data lies between -9.41% and 7.39% with a probability approximately equal to 2/3.

d) Confirmed. The standard deviations of PEG's average annual MFP growth rates using capacity and volumes as output are 1.71% and 13.56%, respectively. Please see Attachment M2-11.1-EP, Tab 1.

e) Confirmed. Please see Attachment M2-11.1-EP, Tab 1.

f) Please see Attachment M2-11.1-EP, Tab 2. The t-statistic is -0.42 and the critical value for the requested test is 2.201. Since .42 is less than 2.201, we cannot reject the null hypothesis that the population mean is 0. However, we note that the small sample can lead to inaccurate results when performing the requested test.

g) Please see Attachment M2-11.1-EP, Tab 1. The t-statistics for the 1996-2014 period are 0.73 and -0.65 using capacity and volume as the output measures, respectively. The t-statistics for the 2003-2014 period are 0.27 and -0.51 using capacity and volume as the output measures, respectively. The critical value for the requested test is 2.101. Since the absolute values of all four t-statistics are less than 2.101, we cannot reject the null hypothesis that the population mean is 0 in any of the four scenarios.

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1]

(Larger Sample)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1996	-1.14%	1.29%	2.96%	6.88%	3.89%	-5.03%	-2.60%
1997	1.04%	-0.76%	-1.77%	-5.08%	-2.31%	3.34%	1.55%
1998	0.14%	6.75%	-1.21%	-4.56%	-1.70%	1.84%	8.45%
1999	-0.60%	-15.88%	-1.77%	8.21%	-0.58%	-0.02%	-15.30%
2000	0.13%	-10.55%	-1.60%	-11.97%	-1.90%	2.02%	-8.66%
2001	0.38%	-13.19%	-1.70%	5.79%	-1.43%	1.82%	-11.76%
2002	-0.67%	10.04%	-1.64%	-0.16%	-1.61%	0.94%	11.65%
2003	0.12%	17.89%	-1.50%	4.65%	-0.66%	0.78%	18.55%
2004	-0.20%	-9.59%	-1.70%	5.09%	-0.70%	0.51%	-8.89%
2005	0.45%	5.17%	-1.25%	1.89%	-0.79%	1.24%	5.96%
2006	0.20%	0.62%	0.62%	-5.78%	-0.25%	0.45%	0.87%
2007	1.48%	-31.85%	-1.34%	11.12%	0.98%	0.50%	-32.83%
2008	-0.12%	3.15%	-0.92%	2.07%	-0.15%	0.03%	3.29%
2009	0.10%	21.86%	-0.67%	4.82%	0.79%	-0.68%	21.08%
2010	-0.01%	-2.06%	-0.78%	3.57%	0.23%	-0.24%	-2.29%
2011	0.08%	2.38%	0.77%	0.79%	1.04%	-0.96%	1.34%
2012	-0.05%	-20.85%	0.50%	0.11%	0.44%	-0.49%	-21.29%
2013	1.77%	8.36%	1.40%	0.64%	1.24%	0.53%	7.12%
2014	0.72%	-13.04%	2.52%	0.46%	1.83%	-1.12%	-14.88%
Averages:							
1996-2014	**0.20%**	**-2.12%**	**-0.48%**	**1.50%**	**-0.09%**	**0.29%**	**-2.03%**
2003-2014	**0.38%**	**-1.50%**	**-0.20%**	**2.45%**	**0.33%**	**0.05%**	**-1.83%**
Standard Deviations							
1996-2014						**1.71%**	**13.56%**
2003-2014						**0.74%**	**15.62%**
T-Statistic							
1996-2014						**0.73**	**-0.65**
2003-2014						**0.27**	**-0.57**

1 Growth rates are calculated logarithmically.

Energy Probe Interrogatory #2

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

In Chart 1 at p.2 of its response to Undertaking JT3.24, LEI provided the annual TFP growth rate that it had calculated for each of the 16 companies for each of the 12 years in its sample:

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
OPG	-3.20%	5.90%	-5.30%	1.10%	-4.20%	11.10%	-1.70%	-16.70%	6.60%	-6.60%	6.10%	0.80%
AB Power	33.60%	-27.00%	0.40%	-37.40%	-82.80%	50.20%	97.00%	-51.40%	-12.00%	-19.20%	72.50%	-40.90%
AP Power	50.70%	-17.70%	-15.20%	-7.00%	-5.20%	-12.10%	19.60%	-6.40%	-3.30%	6.20%	13.80%	-33.30%
Ameren	-8.80%	30.40%	2.70%	-76.70%	46.80%	6.20%	2.60%	8.00%	-6.10%	-26.60%	21.00%	-23.70%
Avista	-14.80%	6.50%	-5.90%	12.40%	-11.30%	3.90%	-3.20%	-6.90%	24.30%	-9.60%	-14.20%	15.10%
Duke	21.50%	-26.70%	8.80%	-12.80%	-6.60%	4.70%	-1.30%	-2.90%	-10.80%	-6.30%	26.50%	-3.10%
GPA	50.70%	-35.70%	8.00%	-35.00%	-18.20%	-36.50%	110.30%	-22.20%	-13.40%	5.80%	65.10%	-38.10%
ID	1.70%	-2.90%	2.80%	39.40%	-40.40%	11.00%	16.30%	-10.00%	40.60%	-32.60%	-34.50%	9.40%
PacifiCorp	5.50%	-16.10%	-3.50%	36.50%	-21.70%	0.00%	-7.00%	8.30%	21.40%	-4.70%	-32.80%	20.40%
PG&E	10.30%	-7.40%	14.50%	17.80%	-61.00%	-0.30%	9.60%	16.10%	13.30%	-50.10%	-2.30%	-25.80%
Portland	-1.30%	3.30%	-9.40%	23.20%	-14.90%	0.10%	-1.10%	6.20%	7.70%	-9.80%	-14.90%	-4.90%
SCE&G	28.90%	-12.20%	12.20%	-26.50%	8.00%	-13.90%	-3.70%	0.80%	-13.40%	6.70%	2.50%	-28.40%
Seattle	-12.90%	-1.10%	-7.50%	19.10%	-4.20%	-4.20%	-6.90%	-2.90%	28.30%	-9.70%	-16.80%	17.10%
SEPA	50.20%	-10.80%	12.20%	-58.70%	-0.90%	-17.20%	28.40%	14.80%	-13.90%	-11.40%	34.60%	-5.70%
SoCal	14.20%	-13.20%	37.20%	-2.50%	-70.10%	2.10%	33.50%	11.30%	9.60%	-48.70%	-20.80%	-24.30%
VA	6.60%	-14.30%	-20.60%	9.50%	15.00%	-40.50%	30.30%	19.80%	-12.50%	48.10%	-38.90%	-1.70%

LEI's Chart 1 also provides the average TFP growth over the entire 2003-2014 period for each company in its sample, referred to as the AVG. For example, the Chart shows that OPG's AVG was -0.49%.

a) Please confirm/disconfirm that OPG's AVG over the 12-year sample period is -0.51% rather than -0.49% as shown in Chart 1. Could the difference simply be due to rounding error? Are there any other instances of such error in Chart 1?

b) Please confirm/disconfirm that the mean of the 16 company AVG's is -1.01% and that the sample standard deviation is 2.37% (using the sample-variance formula in LEI's response to Undertaking JT3.24.

c) P.15 of the PEG reports states: "The productivity growth rates of individual companies tend to be more volatile than the average productivity growth of a group of companies". The data from Chart 1 above appear to support this statement. The sample standard deviation of the company AVG's is 2.37% (subject to check). However, the range of standard deviations of the individual company AVG's is 7.50% (for OPG) to 54.02% (for AB Power). (PEG may wish to confirm this range.) What accounts for this difference in volatility?

d) The LEI data in Chart 1 can also be averaged over the 12 company TFP's for each of the 16 years. For example, it appears that the mean TFP growth rate over all 16 companies was 14.56% for 2003 and -8.69% for 2004. Please confirm/disconfirm that the mean of those 12 year-averages is also -1.01, and that the sample standard deviation is 10.77%.

e) Taking all the 12-company TFP data for each of 16 years together, please confirm that the total number of TFP growth rate observations is 192, that the mean is -1.01% and that the standard deviation is 26.40%.

f) Please briefly discuss the relationship(s) among the standard deviation for the total sample of 192 observations (26.4%), the standard deviation of the 16 observations of company AVG's (2.37%) and the standard deviation of the 12 observations of the year-averages (10.77%).

g) If there is a relationship among the respective variances (rather than the standard deviations), what is that relationship? For example, can it be concluded that the variability in annual TFP growth rates is partly due to inter-company differences, and partly due to differences between business conditions in different years, apparently leaving a very large portion of the total variability unexplained?

h) What, in PEG's view, are the policy implications of adopting LEI's estimate of -1.01% when so much of the variability in its sample is, apparently, unexplained?

i) As LEI had done, please provide PEG's estimates of annual productivity growth for each company in its sample and for each year in its sample.

<u>Response:</u>

The following response was provided by PEG:

a) Confirmed. Yes, the difference could be due to rounding error. Yes, there are several other instances of such error. Please see the column labeled "Company AVG" in Tab 3 of Attachment M2-11.1-EP.

b) Confirmed. See tab 3 of Attachment M2-11.1-EP.

c) The Energy Probe calculations compare apples to oranges. PEG was saying that the average year to year growth rates of sample utilities are less volatile than the year to year growth rates of individual utilities.

d) Confirmed. See tab 3 of Attachment M2-11.1-EP

e) Confirmed. See tab 3 of Attachment M2-11.1-EP

f) The standard deviation of the total sample is larger than the standard deviation of the company AVG's and the standard deviation of the year-averages.

g) The relationship among the variances is similar to the relationship among standard deviations in the sense that the variance for the total sample (6.97%) is larger than the variance of the 16 observations of company AVG's (.06%), and the variance of the 12 observations of the year-averages (1.16%). Yes, that is a plausible interpretation of the data. However, it should be noted that both PEG and LEI set out to compute actual observed TFP trends of OPG's peers, not to fully explain the drivers of productivity growth.

h) The working papers provided in response to M2-11.1-OPG-1 contain year-by-year productivity growth rates for the individual companies in the sample.

Energy Probe Interrogatory #3

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

In its interrogatory #31 to LEI, Energy Probe provided data on negative MFP growth in the Canadian business sector and observed that:

> The CANSIM data tend to support LEI's conclusion of declining productivity growth in the study period used in its Updated Report. In the overlapping eight years, the CANSIM series has five negative growth years and the mean annual growth rate is -0.25%; the Updated Report (Figure 27) has 3 negative growth years and the mean annual growth rate is -0.54%.
> (Ex L/T11.1/Sch 6 EP-031/Page 2 of 4)

PEG's analysis of OPG MFP for the 2013-2014 period shows only one year (2014) of negative MFP growth.

At p.60 of the PEG report, PEG argues for a longer sample period because it "more effectively smooths the effects of volatility in the sample. On the other hand, a more recent sample reflects more recent business conditions, and the effects of the benchmark year adjustment are further in the past."

a) Casually speaking, is it PEG's view that a longer sample period is likely to include both "ups" and "downs" in business-cycle conditions which, in essence, average out to (or near to) zero over a sufficiently long sample period? And if so, does PEG believe that for a sufficiently long sample period, business-cycle conditions can appropriately be omitted from a study of the determinants of multifactor productivity growth for that period?

b) Correspondingly, is it PEG's view that if the sample period is too short, then these short-run business-cycle factors may be significant determinants of productivity growth in that period and should not be omitted?

c) In PEG's view, are there aspects of LEI's productivity-measurement approach that make its estimates more sensitive to general trends in the business-sector conditions than PEG's own estimates? If so, please identify and briefly discuss.

d) Table 4 (p.51) of the PEG report shows that output growth (based on capacity) declined markedly in the 2003-2014 period from the 1975-1995 period, in both the Common Sample and the Larger Sample. In PEG's view, why was hydro output growth so low in the more recent period compared to the earlier period?

Response:

The following response was provided by PEG:

a) PEG believes that, while a long sample period can greatly reduce concerns about the effect of business cycle conditions on estimates of long-term MFP trends, available sample periods may not be long enough to accomplish this.

b) Yes. Our answers to parts a and b of this question suggest that there are benefits to avoiding productivity measurement methods that needlessly increase productivity index volatility.

c) Yes. Most notably, LEI uses the delivery volume rather than generation capacity as the output variable.

d) Slower growth in hydroelectric generation capacity was likely due primarily to reduced opportunities for investor-owned utilities to add cost-effective capacity.

Energy Probe Interrogatory #4

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

Footnote 21 of p.19 of PEG's report states:

> *Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases*

a) Is a stretch factor added only or primarily for the purpose of sharing the financial benefits of performance improvements with customers, or are there other reasons why a stretch factor is added to the formula? If so, please indicate and discuss briefly.

b) Please briefly discuss the circumstances in which a positive stretch factor may not be warranted.

c) The PEG report discusses Efficiency Carryover Mechanism ("ECM") at p.66. Is the stretch factor an ECM? Do stretch factors and ESM's have different rationales?

Response:

The following response was provided by PEG:

a) A stretch factor may in principle address a broader range of conditions that can cause the productivity growth of a utility to differ from that of its peers. One such consideration is the current level of operating efficiency. A utility is more likely to achieve rapid productivity growth to the extent that its current level of efficiency is low.

b) A positive stretch factor might not be warranted for a company that has outstanding operating efficiency or a highly depreciated capital stock.

c) A stretch factor can function as an efficiency carryover mechanism. Suppose, for example, that a company has done a good job of containing its capital expenditures during an IRM. If its capital cost is still forecasted to be low in the (forward) test year of the rebasing to set rates for year 1 of the next plan, it can earn a good performance rating and a lower stretch factor.

SEC Interrogatory #1

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.6 and 64] Please provide an estimate of the appropriate increase in the X factor if the CRVA is approved as proposed, and the basis for that estimate.

Response:

The following response was provided by PEG:

It is difficult for PEG to estimate the appropriate increase in the X factor without more information from OPG concerning the scale of plant additions it expects to address with the CRVA. Pending receipt of further information, PEG has recalculated the MFP trend of its featured large sample peer group excluding 25% and 50% of plant additions to show the directional effect of excluding additions. Results are presented in Attachment M2-11.1-SEC-1. It can be seen that, over the featured 1996-2014 sample period, the average annual MFP growth rate with 25% of plant additions excluded would rise by 32 basis points to 0.61% annually. With *50%* of plant additions excluded, the average annual growth rate would rise by 66 basis points to 0.95%.

Attachment M2-11.1-SEC-1

Table 1

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(With 25% Reduction in Capex)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1995	2.49%	1.04%	0.72%	2.38%	0.96%	1.53%	0.08%
1996	-1.14%	1.29%	2.96%	6.88%	3.89%	-5.03%	-2.60%
1997	1.04%	-0.76%	-1.99%	-5.08%	-2.50%	3.54%	1.74%
1998	0.14%	6.75%	-1.57%	-4.55%	-2.01%	2.15%	8.77%
1999	-0.60%	-15.88%	-1.99%	8.22%	-0.77%	0.16%	-15.11%
2000	0.13%	-10.54%	-1.86%	-12.05%	-2.12%	2.25%	-8.41%
2001	0.38%	-13.20%	-1.93%	5.87%	-1.63%	2.01%	-11.57%
2002	-0.67%	10.03%	-1.88%	-0.17%	-1.82%	1.15%	11.85%
2003	0.12%	17.89%	-1.78%	4.67%	-0.89%	1.01%	18.77%
2004	-0.19%	-9.60%	-1.93%	5.08%	-0.88%	0.69%	-8.72%
2005	0.45%	5.17%	-1.57%	1.91%	-1.05%	1.50%	6.23%
2006	0.20%	0.71%	-0.11%	-5.77%	-0.89%	1.10%	1.61%
2007	1.51%	-32.04%	-1.64%	11.17%	0.79%	0.72%	-32.83%
2008	-0.11%	3.20%	-1.31%	2.09%	-0.42%	0.31%	3.62%
2009	0.10%	22.09%	-1.10%	4.70%	0.51%	-0.41%	21.58%
2010	-0.01%	-2.04%	-1.19%	3.66%	-0.04%	0.03%	-2.00%
2011	0.09%	2.41%	0.06%	0.89%	0.49%	-0.41%	1.92%
2012	-0.05%	-20.99%	-0.15%	0.13%	-0.07%	0.02%	-20.93%
2013	1.75%	8.45%	0.61%	0.58%	0.63%	1.11%	7.81%
2014	0.70%	-13.15%	1.58%	0.55%	1.04%	-0.34%	-14.19%
Averages:							
1975-2014	**1.40%**	**-0.46%**	**-0.04%**	**1.97%**	**0.31%**	**1.09%**	**-0.77%**
1975-1995	**2.49%**	**1.04%**	**0.72%**	**2.38%**	**0.96%**	**1.53%**	**0.08%**
1996-2014	**0.20%**	**-2.12%**	**-0.88%**	**1.52%**	**-0.41%**	**0.61%**	**-1.71%**
2003-2014	**0.38%**	**-1.49%**	**-0.71%**	**2.47%**	**-0.06%**	**0.44%**	**-1.43%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

Attachment M2-11.1-SEC-1

Table 2

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(With 50% Reduction in Capex)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1995	2.49%	1.04%	0.72%	2.38%	0.96%	1.53%	0.08%
1996	-1.14%	1.29%	2.96%	6.88%	3.89%	-5.03%	-2.60%
1997	1.04%	-0.76%	-2.21%	-5.09%	-2.69%	3.73%	1.93%
1998	0.14%	6.76%	-1.93%	-4.54%	-2.33%	2.47%	9.09%
1999	-0.60%	-15.88%	-2.21%	8.23%	-0.95%	0.35%	-14.93%
2000	0.13%	-10.52%	-2.12%	-12.13%	-2.35%	2.48%	-8.17%
2001	0.38%	-13.21%	-2.17%	5.95%	-1.84%	2.21%	-11.38%
2002	-0.66%	10.01%	-2.13%	-0.18%	-2.03%	1.37%	12.05%
2003	0.12%	17.88%	-2.06%	4.69%	-1.12%	1.24%	19.00%
2004	-0.18%	-9.60%	-2.16%	5.07%	-1.05%	0.88%	-8.55%
2005	0.44%	5.18%	-1.92%	1.94%	-1.33%	1.77%	6.51%
2006	0.20%	0.81%	-0.89%	-5.76%	-1.58%	1.78%	2.39%
2007	1.53%	-32.24%	-1.96%	11.21%	0.59%	0.94%	-32.83%
2008	-0.11%	3.26%	-1.72%	2.10%	-0.71%	0.60%	3.97%
2009	0.10%	22.32%	-1.57%	4.57%	0.22%	-0.11%	22.11%
2010	-0.01%	-2.02%	-1.63%	3.76%	-0.33%	0.32%	-1.70%
2011	0.09%	2.44%	-0.74%	1.00%	-0.10%	0.20%	2.55%
2012	-0.05%	-21.15%	-0.88%	0.16%	-0.62%	0.57%	-20.52%
2013	1.72%	8.54%	-0.30%	0.52%	-0.05%	1.77%	8.59%
2014	0.68%	-13.27%	0.46%	0.65%	0.14%	0.54%	-13.40%
Averages:							
1975-2014	**1.40%**	**-0.46%**	**-0.25%**	**1.98%**	**0.15%**	**1.25%**	**-0.61%**
1975-1995	**2.49%**	**1.04%**	**0.72%**	**2.38%**	**0.96%**	**1.53%**	**0.08%**
1996-2014	**0.20%**	**-2.11%**	**-1.33%**	**1.53%**	**-0.75%**	**0.95%**	**-1.36%**
2003-2014	**0.38%**	**-1.49%**	**-1.28%**	**2.49%**	**-0.50%**	**0.87%**	**-0.99%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

SEC Interrogatory #2

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.10] With respect to capital spending for hydroelectric generators generally:

a) Please provide any data in the possession of the expert showing the normal long term level of capital spending, relative to depreciation, for a hydroelectric generation utility during a period where it is not increasing its capacity.

b) If the expert is able to disaggregate that data based on median age of assets, or based on asset classes (for example, civil works vs. other physical assets), please provide that disaggregation.

c) To what extent, if any, is the applicability of that data, disaggregated or otherwise, to OPG affected by the revaluation of OPG's assets when it was reorganized and became regulated? That is, how if at all should OPG's capital spending pattern (relative to depreciation) be expected to be different from the norm because its assets were revalued?

Response:

The following response was provided by PEG:

a) Attachment M2-11.1-SEC-2 provides data on the depreciation expenses, plant additions, and MFP growth of companies in PEG's sample for the featured 1996-2014 period. It can be seen that companies with a high ratio plant additions to depreciation averaged a 1.18% annual productivity decline. Companies with a low which didn't experience significant capacity additions averaged 0.16% annual growth.

b) PEG's data does not permit it to provide the requested disaggregations.

c) The revaluation of OPG's older assets has greatly increased the company's depreciation expenses relative to its plant additions. This slows OPG's cost growth and reduces the Company's need for rate escalation.

Attachment M2-11.1-SEC-2

Hydroelectric Generation, Plant Additions, Depreciation, and Productivity 1996-2014

Company	pegid	Capacity Increase	Percentage Increase*	Total Gross Plant Additions	Total Economic Depreciation	Ratio	Average Annual MFP Growth
Alabama Power	2	146.77	8.49%	253,699,837	693,059,892	37%	1.4%
Union Electric	8	-	0.00%	400,724,347	355,164,543	113%	-0.3%
Appalachian Power	9	10.54	1.38%	111,285,849	199,510,596	56%	0.5%
Avista	12	101.67	10.60%	240,143,251	340,487,861	71%	0.0%
Duke Energy Progress	20	-	0.00%	56,088,269	79,784,920	70%	0.0%
Duke Energy Carolinas	47	481.21	15.13%	763,630,309	1,034,926,308	74%	1.6%
Georgia Power	64	8.62	0.79%	323,811,284	444,747,630	73%	-0.2%
Green Mountain Power	67	15.83	16.29%	54,818,794	69,682,400	79%	1.6%
Idaho Power	73	0.08	0.00%	226,329,183	531,816,994	43%	0.6%
ALLETE (Minnesota Power)	109	1.77	1.46%	97,394,830	85,184,868	114%	0.4%
New York State Electric & Gas	124	(9.69)	-16.74%	22,605,616	86,705,592	26%	0.8%
Pacific Gas and Electric	142	(40.91)	-1.11%	1,486,954,227	2,044,392,417	73%	0.2%
PacifiCorp	143	(23.03)	-2.19%	675,776,739	566,929,396	119%	-0.5%
Portland General Electric	148	(93.93)	-19.40%	303,388,038	249,528,378	122%	-0.5%
Public Service Company of Colorado	153	(26.55)	-8.16%	72,439,321	76,019,443	95%	-0.6%
Puget Sound Energy	158	(6.79)	-2.34%	710,153,709	222,520,944	319%	-3.6%
Rochester Gas and Electric	159	1.22	2.17%	142,044,517	54,700,552	260%	-3.1%
South Carolina Electric & Gas	167	(1.76)	-0.23%	412,551,676	329,576,686	125%	-0.7%
Southern California Edison	169	5.27	0.45%	638,953,422	647,883,176	99%	0.0%
Virginia Electric and Power	195	456.44	22.78%	132,836,505	641,019,041	21%	3.4%

Average ratio for utilities without significant capacity additions	**113.7%**	
Average MFP Growth		
Ratio Over 100%		**-1.18%**
Ratio Under 100%		**0.72%**
Ratio Under 100% and without significant capacity additions		**0.16%**

* Significant capacity additions are shaded and defined as a percent increase over 5%

SEC Interrogatory #3

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.17 and 39] Please provide any data, whether empirical or anecdotal, on the general relationship between productivity growth and capex as a percentage of depreciation for hydroelectric generators.

Response:

The following response was provided by PEG:

The capital intensiveness of hydroelectric generation means that the multifactor productivity growth which is relevant in X factor calibration is very similar to *capital* productivity growth. The capital productivity growth of a utility tends to be more rapid the higher is the value of older plant relative to the value and quantity of plant additions. This is so because the capital quantity trend is a cost weighted average of the trends in the quantities of old and new plant. The quantity of old plant trends downward due to depreciation whereas the quantity of new plant rises with plant additions. Depreciation expenses tend to be higher the higher is the value of older plant. Hence, a company's capital and multifactor productivity growth will tend to be more rapid the higher is the ratio of depreciation expenses to capex.

Anecdotal evidence on the importance of the relationship between depreciation and capex comes from US regulation of vertically integrated electric utilities. In the era when these utilities relied primarily on large solid fuel power plants for electricity they tended to add capacity only occasionally and in sizable "lumps". Cost surged in years of major plant additions. After major plant additions, utilities often went for several years without base rate increases as the value of these plants depreciated and there was a lull in further additions. In rare cases, utilities operated for more than a decade without rate cases.

It follows that utilities that have recently completed capex surges are more likely to experience brisk productivity growth. This is a concern in the regulation of OPG in the aftermath of the NTP. It will also be a concern for power distributors like Toronto Hydro after they complete the capex surges they are engaged in.

SEC Interrogatory #4

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.19] Please confirm that, conceptually, a stretch factor is intended to capture, and share with customers, some of the value associated with the opportunity for the utility to increase its earnings during IRM due to increased efficiencies. Please advise whether, for a utility that has a history of earning less than its allowed rate of return under cost of service regulation, such as OPG, a stretch factor during IRM is less appropriate. If it is not, why not?

Response:

The following response was provided by PEG:

A stretch factor is an adjustment to the X factor to reflect special operating conditions that affect a subject utility's productivity growth which may not be reflected in the base productivity trend. One of these conditions is the expectation that the incentive for productivity growth will be stronger under the IRM than the incentive under the regulatory systems that utilities in the productivity peer group experienced during the sample period. Another relevant condition is the Company's current level of operating efficiency. All else being equal, productivity growth will tend to be higher (lower) for companies with lower (higher) initial operating efficiency.

<u>SEC Interrogatory #5</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2

[p.48] Please explain whether the exclusion of A&G costs in the LEI and PEG studies creates a potential bias in the productivity results. If that does create a bias, can that bias be characterized, directionally or otherwise?

<u>Response:</u>

The following response was provided by PEG:

There are several arguments for excluding A&G expenses from a productivity study intended to calibrate OPG's X factor. One is that allocations of A&G expenses between the operations of a utility (e.g. between nuclear and hydroelectric generation) tend to be arbitrary. Another is that these expenses were peculiarly sensitive to the restructuring of some US electric utilities to foster retail competition which occurred after 1990. There is a risk that any trend in allocated expenses which occurred during these years is atypical of the trend going forward. A third argument is that A&G expenses are a small part of the total addressed in an MFP study and have little impact on MFP results.

One argument for *including* A&G expenses in the productivity calculations is that they are likely to be addressed by the price cap index approved for OPG. Another is that in ratemaking these expenses are allocated between utility operations using sensible rules of thumb. Sensible rules of thumb can also be used to allocate these expenses in a productivity study. It is also notable that only a few of the companies in the hydroelectric productivity studies of PEG and LEI (e.g. Pacific Gas and Electric and Southern California Edison) experienced restructuring during the sample period.

The bias that results from excluding A&G expenses from the productivity calculations is an empirical issue. Attachment M2-11.1-SEC-5 contains productivity results that reflect an allocation of A&G expenses net of franchise fees and pensions and other benefit expenses. Franchises fees are already included in the analysis as part of taxes. Pension and other benefit expenses have been removed to avoid comparability issues between the US and Canada, and because these expenses are likely to be addressed by variance accounts in OPG's plan. With the inclusion of the net A&G expenses, the average MFP growth of sampled utilities *declined* by 4 basis points from 0.29% to 0.25% over PEG's featured 1996-2014 period.

Attachment M2-11.1-SEC-5

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(Larger Sample with Allocated A&G)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1996	-1.12%	1.32%	2.87%	5.82%	3.84%	-4.96%	-2.53%
1997	1.01%	-0.73%	-1.75%	-3.72%	-1.98%	2.99%	1.25%
1998	0.14%	6.57%	-1.21%	-5.08%	-1.85%	1.98%	8.41%
1999	-0.63%	-15.67%	-1.77%	9.62%	-0.17%	-0.46%	-15.50%
2000	0.14%	-10.53%	-1.60%	-7.82%	-1.25%	1.39%	-9.28%
2001	0.38%	-13.53%	-1.70%	0.60%	-2.43%	2.81%	-11.11%
2002	-0.71%	10.09%	-1.63%	2.01%	-1.14%	0.44%	11.24%
2003	0.13%	17.69%	-1.50%	1.48%	-0.87%	0.99%	18.56%
2004	-0.21%	-9.49%	-1.70%	3.70%	-0.74%	0.53%	-8.76%
2005	0.45%	5.21%	-1.24%	2.01%	-0.69%	1.14%	5.91%
2006	0.21%	0.82%	0.58%	-5.80%	-0.55%	0.76%	1.37%
2007	1.44%	-31.86%	-1.34%	10.45%	1.29%	0.15%	-33.15%
2008	-0.12%	3.19%	-0.91%	1.33%	-0.21%	0.09%	3.39%
2009	0.11%	21.55%	-0.66%	4.61%	1.10%	-0.99%	20.45%
2010	-0.01%	-2.04%	-0.77%	3.88%	0.38%	-0.39%	-2.42%
2011	0.10%	2.65%	0.76%	0.22%	1.12%	-1.02%	1.53%
2012	-0.05%	-21.03%	0.51%	0.54%	0.53%	-0.57%	-21.56%
2013	1.74%	7.99%	1.41%	0.31%	1.18%	0.57%	6.82%
2014	0.72%	-13.05%	2.49%	-0.53%	1.51%	-0.79%	-14.56%
Averages:							
1996-2014	**0.20%**	**-2.15%**	**-0.48%**	**1.24%**	**-0.05%**	**0.25%**	**-2.10%**
2003-2014	**0.38%**	**-1.53%**	**-0.20%**	**1.85%**	**0.34%**	**0.04%**	**-1.87%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

SEC Interrogatory #6

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.55] Please confirm that it is reasonable to conclude, from this data, that in a steady state operating mode (i.e. excluding the Niagara Tunnel impacts) OPG has demonstrated that it is able to operate its hydroelectric generating business at a cost that escalates at inflation less 1.35%, and that in none of the years from 2002 to 2013 did its overall costs go up, relative to outputs, by an amount exceeding inflation.

Response:

The following response was provided by PEG:

PEG cannot agree that "OPG has demonstrated that it is able to operate its hydroelectric generating business at a cost that escalates at inflation less 1.35%." It is not clear that OPG's cost trend was normal over the 2002-2013 period. Its cost growth may have been slowed by good cost management and/or by a preoccupation with other initiatives, such as the Niagara Tunnel Project, which affected cost afterwards. On the other hand, completion of the NTP should slow OPG's hydroelectric generation cost growth going forward as the large plant addition depreciates.

SEC Interrogatory #7

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.60] Please explain the pros and cons of using, as the X factor for OPG going forward:

a) The MFP trend for the PEG sample, 0.29%, plus a stretch factor, versus

b) The steady state MFP trend actually achieved by OPG from 2002 to 2013, 1.35%, with or without a stretch factor.

Response:

The following response was provided by PEG:

Setting aside the issue of how the operation of capital cost trackers affects the appropriate X factor for OPG, PEG can identify the following pros and cons of these two price cap index formulas.

<u>0.29% + Stretch factor Pro</u>

Based on rigorous industry productivity research

Reflects the normal capex of old hydroelectric generating stations

Reduces the need for supplemental capital revenue, thereby lowering regulatory cost and weakening cost performance incentives.

<u>0.29% + Stretch factor Con</u>

May not reflect the productivity trend of OPG in the immediate aftermath of completing the NTP; yet OPG will likely seek full compensation for abnormally slow productivity growth during future capex surges

<u>1.35% Pro</u>

May better reflect the cost and productivity trend of OPG in the immediate aftermath of completing the NTP

<u>1.35% con</u>

Use of OPG's own productivity trend would weaken its performance incentives in repeated applications.

SEC Interrogatory #8

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.63] Please estimate, if possible, the materiality threshold that would be appropriate for an OPG hydroelectric ICM given its forecast asset lives and the proposed 0.59% X factor.

Response:

The following response was provided by PEG:

PEG has not had the mandate or funding in this project to consider the optimal materiality threshold for an OPG hydroelectric ICM. However, it believes that the threshold formula approved for power distributors in EB-2014-0219 is generally applicable. The growth factor in this formula should be amended to exclude billing determinants (e.g. number of customers served) that are irrelevant to hydroelectric generation. The capex forecast should be based to the extent possible on sensible formulas to reduce regulatory cost and strengthen capex containment incentives.

SEC Interrogatory #9

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2

[p.64] Please assess whether, if a CRVA is approved, an ICM or ACM should also be available. If more than one mechanism is approved, what adjustments if any should be implemented to integrate those mechanisms with each other, and with the price cap formula?

Response:

The following response was provided by PEG:

PEG believes that the CRVA should ideally be eliminated and that any problem with capex surges should instead be addressed by an ICM/ACM mechanism. In a first generation plan, this mechanism could be similar to that which the Board has developed for power distribution. A key feature of the current ICM/ACM regime is a materiality threshold that recognizes the funding for capex which is available from depreciation, price cap escalation, and billing determinant growth. The threshold formula also contains a dead zone (currently 10%) that, in addition to reducing regulatory cost, strengthens capex containment incentives and guards against overcompensation for capex surges. Refinements to the ICM/ACM mechanism can be considered for the second-generation IRM.

PEG nonetheless recognizes that a CRVA may be approved in this proceeding. In that event, the need for an ICM/ACM mechanism is reduced since many of the capital projects that the mechanism might address will instead be addressed by the CRVA. It is difficult to design an appropriate ICM/ACM mechanism for the residual capital cost without further clarification from OPG regarding the plant additions that the CRVA would and would not address. Better definition of the working of the CRVA with respect to what hydroelectric generation capital projects and costs can be tracked and how the costs will be reviewed for recovery is recommended.

PEG has also noted that, if the CRVA is approved as proposed, an X factor based on the industry MFP trend may no longer be appropriate without adjustment since the price cap index applies to the declining cost of older plant but not to a sizable share of the growing cost of new plant.

PEG may revise its response to this question if OPG provides further information in response to SEC's interrogatories.

VECC Interrogatory #1

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 Data Structural Changes

The authors take issue with LEI as to the most suitable sample period for their study. OPG has suggested 2002-2014, whereas PEG considers a longer period a better choice. OPG's argument for exclusion of earlier years is, in part, that there were structural changes in the North American electricity market in the late 1990s/early 2000's which would make inclusion of earlier data less meaningful.

a) Are there methodologies available to test for structural breaks in time-series data?

b) If so, has PEG tested its sample data for such structural breaks?

c) If the event that structural change was indicated in the data sets are there quantitative methods to adjust for this?

Response:

The following response was provided by PEG:

a) Yes.

b) No.

c) Not applicable.

VECC Interrogatory #2

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory:

Reference: Exhibit M2 Data Discrepancies

At page 31 of the PEG study there is a discussion of discrepancies as between the data used by PEG and that used by LEI. The authors note that using the PEG version of generation volumes increased the trend in MWh by 0.05%

a) Was the 0.05% the result of keeping all other factors the same as in the LEI model?

b) Is the noted 0.05% the only difference found in using the PEG rather than LEI data?

Response:

The following response was provided by PEG:

a) Yes. The 0.05% represents the difference in the trend between the PEG values for MWh and those for LEI for the companies common to both studies.

b) No. The O&M data also differed. No adjustment was made to the results for this observation. The purpose of highlighting of the 0.05% value was to acknowledge that a difference existed between the data sources and the impact was small.

<u>VECC Interrogatory #3</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 Capacity Refurbishment Variance Account

At pages 61-65 (section 6.2.3) the authors discuss the impact and wisdom of continuation of the Capacity Refurbishment Variance Account.(CRVA) At page 64 there is a discussions of three options that could be employed "[*I*]f *eligible capex (to the CRVA) is of a kind routinely incurred by utilities in the productivity sample, consideration should be paid to how other IRM provisions can be adjusted to better ensure that customer receive the benefit of industry productivity growth in the longer run*."

a) In the authors' view what would be the preferred solution – elimination of the CRVA or an adjustment in the plan to address issues arising from use of the account? Please explain.

<u>Response:</u>

The following response was provided by PEG:

a) Please see PEG's response to M2-11.1-SEC9.

<u>VECC Interrogatory #4</u>

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

<u>Interrogatory</u>:

Reference: Exhibit M2 Efficiency Carryover Mechanism

Beginning at page 63 there is a discussion of the benefits of including an Efficiency Carryover Mechanism (ECM).

a) Can the authors provide a reference to any North American utilities who have included such a mechanism in their rate plans?

b) If yes, please provide a short description of how the ECM operates for that utility.

<u>Response:</u>

The following response was provided by PEG:

a) PEG is aware of several North American utilities that have had an ECM in their rate plans. North American IRMs that have included an ECM include the current generation of PBR plans for Alberta's power and gas distributors (except Enmax), AmerenUE, Green Mountain Power, BC Gas (now FortisBC Energy), and various current and former subsidiaries of National Grid including Massachusetts Electric and Energy North Natural Gas.

b) PEG has previously developed commentary on North American ECMs and provides it here with minimal adaptation.

1. Alberta

The Alberta approach to ECM design calculates an average of surplus and deficit earnings achieved during an MRP and then permits the utility to keep 50% of net gains during the next plan period up to 50 basis points of ROE. The bonus amount applies for 2 years after the PBR term.

2. AmerenUE

AmerenUE is a vertically integrated electric utility providing service to St. Louis and other areas of eastern Missouri. In the 1990s AmerenUE operated under two Experimental Alternative Regulation Plans ("EARPs"). The plans included earnings sharing mechanisms. Between EARP I and EARP II, the revenue requirement was not trued up fully to an estimate of the company's cost. The difference was a weather-normalized average of AmerenUE's share of the surplus earnings under the previous plan. This provision was, essentially, an ECM.

3. Green Mountain Power

In 2012 Gaz Metro offered to purchase Central Vermont Public Service Company ("CVPS") and to merge CVPS into Green Mountain Power ("GMP"), a previous Gaz Metro acquisition. The merger was approved by the Vermont Public Service Board ("the Board") after memorandums of understanding were reached between the petitioners and the Vermont Department of Public Service and IBM (a large GMP customer). The memorandums outlined the integration of CVPS and GMP's currently effective IRMs, wherein each company was required to file its cost of service annually but the revenue requirements for O&M expenses and some capital costs were limited to the growth in CPI-X, with X being determined in part based on each company's performance. New plant additions and retirements were addressed through traditional cost of service ratemaking. As part of the integration process, the combined company agreed to file a rate case with a rate effective date prior to October 1, 2014.[1]

The combined company committed to deliver at least $144 million of O&M savings to customers over a ten year period beginning October 1, 2012. The memorandum of understanding with the Vermont Department of Public Service outlined guaranteed savings through rate credits of $2.5 million in year 1, $5 million in year 2, and $8,000,000 in year 3. Any savings beyond the credited amounts for the first three years would be retained by the combined company.[2] For years 4 through 8 after the merger, estimated savings would be shared 50/50 between the combined company and its customers. After year 8, all savings would be passed through to customers. Since GMP retains benefits of long term efficiency gains that it realizes in the first three years after the rate case this mechanism is, effectively, an ECM.

The calculation of savings begins by adjusting the base year (pre-merger) O&M expenses to remove the costs and benefits of special undertakings that the

[1] The rate case led to the approval of an IRM that was similar to the existing IRM.
[2] Customers receive 100% of all non-O&M cost savings.

combined companies already had underway at the time of the merger (e.g., CVPS' AMI installation and staff reductions). The adjusted base year O&M cost is then escalated using the existing PBR plan escalators for each year. Savings are determined by comparing the adjusted base O&M cost with the actual O&M cost, as filed by the combined company in each year. To the extent that O&M savings do not reach the guaranteed amount, the combined company will incur a loss.

4. BC Gas

BC Gas (later called Terasen Gas, now known as FortisBC Energy), operated under two PBR plans between 1998 and 2009. The first plan had a three year term where the revenue requirement would change based on separate treatments for O&M expenses, minor capital additions, and major capital additions. O&M cost was escalated completely through indexing. Capital additions were broken into seven categories, with five of the categories following a similar escalation methodology as O&M cost, so that

$$\text{Allowed Base Unit Cost}_t = \text{Base Unit Cost}^{1998} * (1 + \text{Inflation}_t - \text{Productivity}_t)$$

$$\text{Allowed Capital Spending}_t = \text{Allowed Base Unit Cost}_t * \text{Units}_{t\,.}$$

Here the *Base Unit Cost* was a fixed value for each capital category, *Productivity*$_t$ and *Inflation*$_t$ were identical to the O&M definition, and *Units*$_t$ were defined for each category (e.g., for mains, units are defined as a percentage of forecast customer additions multiplied by an allowed quantity of main per addition).

The sixth category, all other plant, featured the same escalation methodology as O&M expenses and the first five capital expenditure categories, save for an escalation based on unit costs. The final capital expenditure category, which included the largest capital expenditures, was provided ratemaking treatment that was little different from cost of service ratemaking.

A feature of the BC Gas PBR plan unique among North American PBR plans was the Capital Efficiency Mechanism. This mechanism was designed to incent the company to be efficient in its capital spending except for reliability, system integrity, and large capital projects. To the extent that the actual unit cost varied from allowed unit cost, the unit cost variance would be multiplied by the number of units (e.g., meters of main installed for the year) and added to rate base. These adjustments to rate base would be phased out evenly over three years, so that variances in years two and three of the PBR plan would continue to be reflected in rate base beyond the term of the plan.

<u>The Second Plan</u>

Negotiations for the second PBR plan resulted in a settlement outlining the terms of BC Gas' 2nd Generation PBR plan. The plan had a four year term, beginning in 2004 and ending in 2007.[3] O&M cost was escalated completely through indexing, with revenue requirement changes based on the growth in the forecast CPI for British Columbia less implicit productivity factors of 50% of CPI in 2004 and 2005 and 66% of CPI for all succeeding years, plus the growth in the number of customers. Capital expenditures were broken into three categories to determine their ratemaking treatment: customer addition driven capital expenditures, other base capital expenditures, and capital expenditures requiring Certificates of Public Convenience and Necessity. Two of the categories followed a similar escalation methodology as O&M cost, so that

$$\text{Allowed Unit Cost}_{c,t} = \text{Unit Cost}_c^{\text{Base}} * (1 + \text{Inflation}_t - \text{Productivity}_t)$$

$$\text{Allowed Capital Spending}_{c,t} = \text{Allowed Unit Cost}_{c,t} * \text{Units}_{c,t}.$$

Here the $\textit{Unit Cost}_{c,t}$ was a fixed value for each capital category, c, and $\textit{Productivity}_t$ and $\textit{Inflation}_t$ were identical to those in the O&M formula, and $\textit{Units}_{c,t}$ were defined as customer additions for customer addition driven capital expenditures and the total number of customers for other base capital expenditures. The third capital expenditure category was provided ratemaking treatment that was little different from cost of service ratemaking.

Similar to the first plan, the new plan had a phase out of the final year capital benefit.[4] Benefits were based on the following formulas:

$$Savings = \sum_p Actual\ Spending_{t-s} - Allowed\ Spending_{t-s}$$

$$Shareable\ Savings = (14\% * Savings)$$

The company's portion of the shareable savings was set at 50%, with the company receiving 2/3 of that amount in the first year after the plan and 1/3 of that amount in the second year. After that period, capex savings accrued to customers.

[3] The plan was subsequently extended through 2009.
[4] A more expansive ECM proposed by the company, the Full Term Efficiency Incentive, was not accepted as part of the PBR settlement.

5. Massachusetts Electric

New England Electric System ("NEES") and Eastern Utilities Associates ("EUA") were New England electric utilities in the process of merging when they were acquired by National Grid ("Grid"). In 2000, the Massachusetts Department of Telecommunications and Energy ("DTE") approved a settlement resolving a host of regulatory issues. The settlement detailed a "performance based" rate plan under which the Massachusetts distribution utilities of the two companies (Massachusetts Electric and Nantucket Electric) would operate.[5] The plan had a ten year term.

The settlement did not require rates to be reset in a rate case at the conclusion of the Rate Index Period. However, in a section entitled "Limits on Adjusting Rates Following the Rate Plan," it limited over a ten year "Earned Savings Period" the extent to which the rates established in future rate cases can reflect the benefits of cost savings that were achieved during the plan. Specifically, let

"Earned Savings" = Distribution revenue under rates applicable in March 2009

- pro forma cost of service ("COS") (which includes applicable income taxes but not acquisition premiums or transactions costs).

The 2009 date was chosen since it was the first year during which the Company could file a rate case under the plan. Then, during the Earned Savings Period, Massachusetts Electric was permitted to add to its cost of service during any rate case the *lesser* of a) $66 million and b) 100% of Earned Savings up to $43 million and 50% of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. If there were earned savings, they would be capped at $66,000,000.

Under these terms, if National Grid filed a rate case in 2010 based on a 2009 test year and its cost of service was $30 million less than its base rate revenue in that year it would not be required to reduce rates.[6] If its COS was $80 million below base rate revenue, it would be required to reduce rates by only $14 million.

6. Energy North Natural Gas

In 2006, National Grid announced its plan to purchase Keyspan. Grid already owned a New Hampshire power distributor, Granite State Electric and, as part of the Keyspan acquisition obtained the New Hampshire gas distributor Energy North Natural Gas ("Energy North"). A settlement approved by the Commission

[5] See "Rate Plan Settlement," November 29, 1999. The DTE approved the settlement in D.T.E. 99-47.
[6] Massachusetts does not have forward test years.

dealt with the merger and created separate rate plans for Granite State and Energy North.[7]

Energy North's approved plan was based upon a ten year rate agreement period. This plan allows for a ten year amortization of the costs to achieve the merger and implements customer service standards. In the expected rate case at the outset of the period a historic test year would be used, based on the pre-merger cost of service ("COS"), adjusted for known and measurable changes, and provide a net synergy savings credit of $619,000 annually.[8]

After the initial rate case, Energy North would be allowed to file one additional rate case at any time. In this follow up rate case, Energy North could add fifty percent of proven net synergy savings to its COS. Proven net synergy savings were defined as the difference between its pre-merger FERC Form 2 Account 900 expenses, escalated for inflation, and those of the post-merger company.[9] [10] In any subsequent rate cases filed by Energy North or at the end of the ten year rate agreement period, Energy North would surrender its claim to future merger savings in its cost of service.

[7] Grid subsequently sold these distributors.
[8] National Grid calculated this amount to be 50% of the net synergy savings expected. This is the estimated Energy North share of the steady state merger savings (approximately $200 million) less its share of the 10 year amortization of the costs to achieve savings of $400 million.
[9] The FERC 900 Accounts include Customer Accounts, Customer Service, Sales, and Administrative & General Expenses. Environmental and uncollectible bill expenses are excluded from this total.
[10] This proof was required after 5 years if Energy North did not file a rate case. Energy North would be permitted to include proven savings in its next rate case if it was initiated during the term of the rate plan.