SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

EB-2016-0152

OPG Panel 2Ai and 2B

1 **Chart 1 – Summary of Hydroelectric Ratemaking Proposal**

Ratemaking Element	4GIRM	OPG Proposal
"Going-In" Rates	Determined in a forward test year cost of service review	Determined in cost of service review of 2014/2015 test year (EB-2013-0321)
Form	Price-cap Index	Price-cap Index
Coverage	Comprehensive (capital and OM&A)	Comprehensive (capital and OM&A)
Annual Adjustment Mechanism	1+(I-X) **Inflation**: Composite Index. Distribution Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD) **X-factor**: Peer group X-factors comprised of: 1. Distribution industry TFP growth potential; and 2. a Stretch Factor	1+(I-X) **Inflation**: Composite Index. Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD) **X-factor**: Peer group X-factors comprised of: 1. Hydroelectric generation industry TFP growth potential; and 2. a Stretch Factor
Role of Benchmarking	1. Assess reasonableness of test year cost forecasts 2. Determine stretch factor	1. Test year review completed in EB-2013-0321 2. Determine stretch factor
Sharing of Benefits	Stretch factor of between 0% and 0.6% based on benchmarking	Stretch factor of between 0% and 0.6% based on benchmarking OPG proposes a stretch factor of 0.3% for the application term, based on the company's hydroelectric benchmarking

Ratemaking Element	4GIRM	OPG Proposal
Term	Five years	Five years
Incremental and Advance Capital Modules	Available on application	Available on application OPG is not proposing an Advance Capital Module
Treatment of Unforeseen Events	Per OEB policy (*Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673)	Per OEB policy (*Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673), with OPG-specific materiality threshold of $10M
Treatment of Deferral and Variance Accounts	Status quo	Status quo, with addition of a variance account to account for the impact of OEB's decision on OPG's request to adjust the common equity ratio
Performance Reporting / Monitoring and Off-ramps	Annual performance reporting A regulatory review may be initiated if a distributor's annual reporting shows performance outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures	Annual performance reporting A regulatory review may be initiated if OPG's annual reporting shows performance outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures

2.2. OEB & Stakeholder Guidance

2.2.1. OEB Policy

With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.

As the RRFE is aimed at rate-making for electricity distributors in Ontario, it is not directly applicable to generators. However, OPG recognizes that many of the objectives and principles addressed in the RRFE can be applied to the generation sector.

The proposed hydroelectric IR framework deviates from 4GIRM only as is necessary to incorporate material differences between the distribution and hydroelectric generation industries and to transition OPG to IR for the first time.[3] Specifically, OPG's proposed model incorporates the following modifications to the 4GIRM methodology:

1. **Inflation factor**: OPG proposed using the same input sub-indices as the OEB's 4GIRM I-factor; however the I-factor is weighted appropriately to reflect the input costs of the hydroelectric generation industry (i.e., not the electric distribution industry) as determined independently by London Economics International LLC ("LEI"));
2. **Productivity Growth**: The independent Total Factor Productivity ("TFP") study reflects growth potential of the hydroelectric generation industry. However, notwithstanding the negative productivity factor identified by the LEI TFP study, OPG is proposing a productivity factor of zero; and
3. **Stretch factor**: Set once at the beginning of the IR plan term (i.e., not revised annually) to place OPG's hydroelectric benchmarking performance in the context of the OEB's 0% to 0.6% stretch factor range.

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[3] Reflects an adjustment to the hydroelectric base rate to remove a 2015 nuclear tax loss (discussed in Section 2.3.2) and a new deferral account to reflect the OEB's decision on common equity (discussed in Section 2.6).

The RRFE requires an X-Factor to be based on industry TFP growth potential and a stretch factor. In its letter of February 17, 2015, the OEB noted its expectation that OPG's hydroelectric incentive rate-making framework would take into consideration the independent productivity study performed by LEI and filed with the OEB on December 19, 2014. That productivity study reflected information for the 2002 to 2012 period. An updated version of the study including data for 2013 and 2014 is filed as Attachment 1 to this schedule. The TFP study results were substantially the same, as demonstrated in Chart 2:

Chart 2 – Summary of Hydroelectric TFP Results

Approach	2002-2012 Information	2013-2014 Update
Average Index	(1.02)	(1.01)
Trend Regression Index	(1.00)	(1.19)

Although LEI's TFP study concludes that a -1% productivity factor is appropriate for OPG's regulated hydroelectric facilities, OPG recognizes that the OEB has declined to accept a negative productivity factor in the context of electricity distribution. OPG therefore proposes a 0% productivity factor for the 2017-2021 IR period. This increase to the productivity factor essentially creates an additional 1% stretch factor for OPG's hydroelectric facilities during each year of the IR period, relative to the industry trend identified in the TFP study.

Total cost benchmarking is an important component of each rate-setting model in the RRFE and plays an important role in OPG's proposed IR frameworks for both hydroelectric and nuclear assets. Under the 4GIRM method, which OPG's hydroelectric IR proposal is based upon, an applicant's benchmark performance is used to determine the stretch factor in the distributor's price-cap index. Similarly, OPG proposes that the hydroelectric stretch factor be determined based on the hydroelectric total cost benchmarking study conducted by Navigant Energy Consulting Inc. ("Navigant"), which is filed as Attachment 2 to this schedule.

As discussed in section 2.3 below, the proposed 0.3% stretch factor is based on the company's hydroelectric benchmarking performance. In determining the value of the stretch

Memo summarizing LEI's review of Energy Probe Research Foundation's "Note on Data Aggregation" (from February 28, 2017)

Briefing memo prepared by London Economics International LLC for Ontario Power Generation Inc.

March 20, 2017

Reference:

- EB-2016-0152 Energy Probe Research Foundation. Note on Data Aggregation

Question:

Energy Probe ("EP") seeks clarification on LEI's calculation of productivity growth rates. In particular EP sought to understand how the -1.01% average TFP growth rate relates to company-level data provided by OPG in response to Undertaking JT3.24.

Response:

LEI notes the following key points regarding its approach:

1. In **Table 1 of its submission** (reproduced below), EP makes rounding errors in its use of LEI's company TFP growth rates and calculation of each company's average TFP growth through its use of the hardcopy data reported to 1 decimal place – however, **overall their numbers in Table 1 are right, except the last row, labelled "YEARLY AVG"** in Figure 1 below.

Figure 1. Excerpt of Table 1 from Energy Probe submission

Annual Total Factor Productivity Growth Rates in LEI Sample
Source: LEI Response to Technical Conference Undertaking JT3.24

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	COMPANY AVG
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%	-0.51%
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%	-1.42%
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%	-0.83%
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%	-2.02%
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%	-0.31%
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%	-0.75%
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%	3.40%
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%	0.07%
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%	0.53%
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%	-5.44%
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%	-1.32%
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%	-3.25%
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%	-0.14%
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%	1.80%
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%	-5.98%
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%	0.07%
YEARLY AVG	14.56%	-8.69%	1.96%	-6.10%	-16.98%	-2.21%	20.17%	-2.13%	4.15%	-10.53%	4.18%	-10.44%	**-1.01%**

Source: Energy Probe Research Foundation. Note on Data Aggregation (EB-2016-0152). February 28, 2017

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4.1. Proposed Performance Measures

OPG proposes to report the company's annual benchmarking performance measures. The hydroelectric performance measures set out in Chart 11 are the same as the key performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B). The nuclear performance measures in Chart 12 are the benchmarks used in the company's annual nuclear benchmarking report.

Chart 11: Annual Hydroelectric Performance Measures

Hydroelectric Performance Measures	
Category	**Measure**
Safety	All Injury Rate (per 200k hours)
	Environmental Performance Index (%)
Reliability	Availability Factor (%)
	Equivalent Forced Outage Rates (%)
Cost Effectiveness	OM&A Unit Energy Cost ($/MWh)

Board Staff Interrogatory #220

Issue Number: 10.2
Issue: Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-2 Chart 11
Ref: Exh A2-2-1 Attachment 1 page 34 Ref: Exh A1-3-2 Attachment 2 page 10

a) On page 34 of Attachment 1 to Exh A2-2-1 (OPG business plan), the operational targets for Hydro Thermal Operations, designed to drive continuous performance, are set out. Why has OPG proposed to report only a few of these measures, and in some cases different measures, e.g. the business plan reports Total Hydroelectric Generating Cost per MWh?

b) The Total Hydroelectric Generating Cost per MWh, as reported in the business plan, would include regulated and non-regulated hydroelectric facilities. Does OPG track Total Hydroelectric Generating Cost per MWh for the regulated hydroelectric facilities? If so, please explain why OPG has proposed annual reporting on OM&A Unit Energy Cost.

c) On page 10 of Attachment 2 to Exh A1-3-2, the functions that Navigant used to benchmark the cost OPG's regulated hydroelectric facilities are summarized. Why has OPG proposed to report only OM&A Unit Energy Cost and not some/all of the cost performance measures used by Navigant?

Response

a) The hydroelectric performance measures proposed within the rate application include all the operational targets defined on p. 34 of Ex. A2-2-1, Attachment 1, with the exception of Capacity and Total Hydroelectric Generating Cost per MWh.

   Capacity is excluded as a performance measure as there is very little opportunity to increase the capacity of OPG's regulated hydroelectric portfolio.

   OPG believes that an appropriate hydroelectric efficiency metric is one that directly relates to the company's regulated hydroelectric operations. The Total Hydroelectric Generating Cost per MWh is a new corporate target adopted in the 2017-2019 business plan, and is applied to OPG's regulated and contracted hydroelectric assets on a combined basis. Therefore, it would not be an appropriate reporting metric of the cost effectiveness for the prescribed hydroelectric facilities. Total Hydroelectric Generating Cost per MWh does not replace the OM&A Unit Energy Cost ($/MWh) measure, which

OPG continues to use as a benchmark to assess the effectiveness of the hydroelectric operations. This information is available annually through EUCG, and is widely used by hydroelectric generators to assess operational performance.

The Environmental Performance Index (EPI) that OPG proposes to report encompasses the individual environmental performance targets referenced in the OPG business plan. The EPI was described in EB-2013-0321, Ex. F1-1-1, p. 10, lines 16-19: "The [EPI] includes a variety of measures and deliverables, some that are specific targets (such as minimizing the number of spills and MOE infractions) and some that are environmental initiatives (such as compliance cost management, Endangered Species Act, etc.)."

b) As noted in part a), Total Hydroelectric Generating Cost per MWh includes both regulated and unregulated hydroelectric generation assets. OPG does not track Total Hydroelectric Generating Cost per MWh for the regulated hydroelectric facilities alone. OPG proposes to report OM&A Unit Energy Cost ($/MWh) rather than Total Hydroelectric Generating Cost per MWh because it is a direct measure of the cost effectiveness of the operation of OPG's regulated hydroelectric stations.

c) Please see the answer to part b) above.

Board Staff Interrogatory #233

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 page 8

The LEI report states: "Because an industry TFP study reports historical productivity growth rates, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically."

a) Please provide evidence that the future business conditions of OPG are similar to those experienced by the companies LEI used to calculate the productivity trend over the 2002-2014 period.

b) Are the productivity trends for very-long lived and mature assets sensitive to the replacement capex undertaken during the sample period?

c) Will the large replacement and upgrade investments made by OPG in recent years slow its cost growth in the next ten years? If so, should this affect the choice of a sample period?

d) How much capital replacement must take place for a "mature" asset to no longer be considered "mature" (i.e. if hypothetically everything was repaired/replaced, is the plant now "new" with all the expectations of a new plant)?

e) If it were possible, would a time period that captures a greater portion of the life cycle such as one starting in the 1970s or 1960s be more representative of future expectations?

Response

The following response was provided by LEI.

a) LEI understands that OPG's future business conditions for the regulated hydroelectric fleet will be similar to what they have experienced in the 2002-2014 period given that OPG's operations are in a steady state. Furthermore, given the overall age profile of the peers selected in the hydroelectric industries (ranging from 35 to 74 years) and the maturity of the assets, LEI expects the general trends in total factor productivity experienced by the peer companies over the study period are relevant to OPG going forward.

b) Replacement capital in hydro operations is typically limited to mechanical and electrical parts; the majority of the asset base, roughly 75%, consists of civil works that is rarely “replaced”. Productivity trends will show improvement when replacement capital increases production, for example, new blades/new runners will be more efficient and will therefore allow for more energy production as measured in MWh terms.

c) No, not necessarily, as discussed in Ex. L-11.1-1 Staff-244, routine operations and maintenance must continue, even as capital improvements are made to replace aging infrastructure, in order to keep the assets in a satisfactory state of performance.

The choice of sample period in LEI’s industry TFP study adequately captures the dynamics associated with capital improvements and ongoing and routine O&M for mature hydroelectric assets.

d) As noted in the answer to part b) above, large hydroelectric generation facilities are comprised mostly of civil assets which do not get replaced. As such, typical capital replacements would never result in a “mature” asset becoming a “new” asset in this industry.

e) More data is not necessarily better. On page 16 of its report, LEI states *“if the range of data is too long, the estimated trends may be biased and not representative of current dynamics. The time period should ideally incorporate more recent data that captures the latest trends in the industry, while eliminating earlier time periods with differing productivity growth drivers.”* LEI considers the 13-year period used in the study appropriate for capturing the current steady state of the industry and avoids the problems associated with relying on stale inputs.

For a number of the peers, a substantial portion of their assets were constructed in the 1950s and 1960s. For example, 42.7% of Pacific Gas and Electric’s portfolio was constructed during this period. The extension of the study period to as far back as the 1960s would capture an industry undergoing a build out or boom. This is not representative of OPG’s regulated hydroelectric fleet going forward as there are little to no more build out opportunities left for this fleet.

Board Staff Interrogatory #237

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, pages 19, 41-42

At page 19 of its report, LEI states that:

> LEI recognizes that the generation output metric is dependent on hydrology and system operations. However, the longer-term nature (thirteen years) of the TFP study compensates for the year-on-year variability in annual generation, and therefore LEI believes variability in annual hydrology should not be an obstacle to this TFP study.
>
> Using OPG as an example, the average of water flows during the period 2002-2014 is within 1% of the twenty year average (1994-2013).

At pages 42-42 of its report, LEI states:

> average growth rate for capital inputs measured in MW was 0.15% over the 2002-2014 period, with little year over year fluctuations. This result is to be expected for a mature hydroelectric industry as construction of new generation facilities is infrequent.... For output, net generation growth rate was on average -0.64% for the industry.[67] Note year over year fluctuations were much more visible compared to the average, which is to be expected due to varying hydrology cycles during the 2002-2014 period, as well as other factors such as changes in demand and surplus baseload generation conditions.
>
> [67]A negative generation growth rate does not imply the same capital is producing less over time, but rather is related to the hydrology cycles at the start and end years of the study.

a) Please explain the decline in the MWh generated by sampled utilities relative to their generation capacity during the sample period.

b) What grounds are there to support that this trend will continue?

c) Was the trend in MWh generated adjusted for changes in hydrological conditions during the sample period?

d) What are the expected volume/capacity and water flow trends of OPG in the next five years and the following five years?

e) Is the volume/capacity trend of the sampled utilities pertinent to an X-factor for OPG?

f) Can footnote 67 be taken to mean that hydrological conditions are the cause of declines in capital productivity in the study?

g) If the generation growth rate is not related to production over time, then why was generation selected as the measure of output quantity?

h) For a given unit whose availability and capacity does not change, would the measured capital productivity be zero, by definition, under normal hydrological conditions using the LEI methodology?

Response

The following response was provided by LEI, except for the response to part d) which was prepared by OPG.

a) As stated in footnote 67, LEI believes the decline in MWh is likely related to the hydrology in the chosen start and end year of the study. Section 6.2.2 of LEI's report discusses the trend regression method, which can be useful in establishing average trends in instances where a series exhibits volatility at its endpoints. It was found that the trend regression method produced more negative, but otherwise very similar results to the average growth method.

b) Production from year to year will vary with hydrology and climatological conditions. However, over the longer term, it is expected that production, as represented by MWh generated over the course of a year, will trend to long term average levels, assuming climatological conditions remain steady.

c) No. LEI used actual reported net generation without any further adjustments.

d) As described in EB-2013-0321 (Ex. E1-1-1), OPG does not perform volume and water flow forecasts for the next five years. For the Niagara Plants, flow forecast information is only available for up to a two-year period, after which flows are assumed to trend back towards historical monthly median flows. For Saunders GS, forecast flows are only available for 6 months, after which flows are projected with trends from the Niagara River flow forecast. For the remaining 48 plants, water flows can change quickly due significant precipitation events, making them difficult to predict reliably. As a result, OPG uses historical median monthly flows for these plants.

e) The electricity produced is the primary output from OPG's hydroelectric fleet, as has been recognized by the format of the volumetric regulated rate that the OEB has applied to

OPG over the years. As such, LEI believes that the volume of production is a relevant element of determining productivity trends for the industry and the X-factor for OPG. Similarly, the capacity of the hydroelectric assets is a metric that represents the physical quantity of capital deployed and is a relevant element of productivity trends.

f) No, LEI is not suggesting that hydrological conditions drive capital productivity down. The footnote specifically states that "a negative generation growth rate does not imply the same capital is producing less over time". The footnote goes on to state that "hydrology cycles at the start and end years of the study" are driving the trend in generation over the study timeframe. LEI uses a trend-based TFP growth rate to address this type of concern, as described in answer to part a) above. Furthermore, on page 15 of the report, LEI states that "[i]n instances where a series is volatile at its endpoints, it can be argued that the 'trend regression' method may give a better estimate of the underlying TFP growth trend, in that it reduces the weight attached to the first and last years of the study period."

g) Generation is an appropriate metric of output for hydroelectric power plants because it represents the primary output from such facilities; the wholesale power market in Ontario remunerates generation on their MWh of energy; and the OEB has also recognized MWh of production as a key element of the rate for OPG.

h) Conceptually, if there is no change in quantity of capital input, which LEI based on rated capacity of generation facilities, and no change in other inputs and outputs, then overall total factor productivity growth rate would be zero.

SEC Interrogatory #96

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

Interrogatory

Reference:

The attached spreadsheet sets out a simple calculation of the expected increases in costs from a capital-intensive business like hydroelectric power generation. It shows $1 million of 50 year assets going into service in year one, with annual costs for cost of capital (debt, equity and taxes) of 8% and depreciation of 2%. OM&A is 15% of total annual costs (excluding gross revenue charge), and there are annual capital additions to replenish the original asset equal to depreciation plus the cumulative impact of inflation.

With respect to the cost drivers affecting a capital-intensive business like hydroelectric power generation:

a. Please confirm that this pattern is an accurate, if simplified, description of the cost drivers on such a business over time. If it is not, please explain the primary ways in which it is incorrect.

b. Please confirm that if both operating and capital costs increase at the rate of inflation every year, with zero productivity, the overall revenue requirement for the business will increase at an average of slightly more than 40% of inflation. Please confirm that this effect will decline (i.e. annual costs will get closer to inflation) as inflation- driven operating costs become a higher percentage of annual costs relative to capital, and will increase (i.e. annual costs will increase at a lower percentage of inflation) as those operating costs become a lower of percentage of annual costs relative to capital. Please confirm that annual costs can only be equal to or greater than inflation if:

   i. Operating costs are 100% of annual costs, or

   ii. Operating costs or capital costs rise significantly faster than inflation

c. Please explain the primary factors causing the costs of the OPG to follow a pattern of increases that are not comparable to the standard cost drivers for capital intensive businesses.

Response

Questions a) and c)

OPG cannot confirm whether the spreadsheet attached to this question accurately reflects the cost drivers of a hypothetical hydroelectric power generator or other sufficiently similar capital-intensive business. OPG is concerned that the broad assumptions made by SEC cannot accurately reflect the cost drivers for a business with the scale and complexity of a province-wide hydroelectric generator like OPG.

OPG has the following specific comments on the assumptions employed in the spreadsheet:

1) **Depreciation**: For capital investment with a defined 50 year life, 2 percent depreciation may be reasonable. In the case of OPG, this value would be lower, closer to 1%.
2) **Cost of Capital and Income Taxes**: If the hypothetical company is based in Ontario, an 8 percent pretax cost of capital is low over the long term. A higher risk hypothetical company would have a higher pre-tax cost of capital.
3) **OM&A excluding Fuel/Gross Revenue Charges**: OPG has no basis to assess the percentage of OM&A costs for a hypothetical utility. OPG's OM&A costs less GRC were approximately 35% of revenue requirement based on the EB-2013-0321 Payment Amount order, which is the base rate proposed for incentive regulation in this application.
4) **Annual Capital Additions**: OPG has no basis to assess whether capital additions at depreciation plus inflation will in fact replenish the asset. For OPG, capital additions are primarily directed at the non-civil structures.

The OEB has regulated capital intensive industries for decades, including both gas and electricity distribution. The OEB has applied several generations of incentive regulation using an index-based incentive regulation methodology to establish rates for these utilities. Hydroelectric generation is similarly capital intensive. There is no fundamental difference in applying a price cap to set rates for hydroelectric generation and natural gas or electricity regulation: all have significant historic investment in property, plant and equipment that is depreciated over its expected useful life, all earn a cost of capital using an industry wide ROE with relative risk reflected in approved common equity ratios, all invest in capital to maintain assets and expand operations, all pay income and property taxes (or taxes in lieu) in Ontario and all incur some level of OM&A costs. The degree of capital intensity among capital intensive industries may be different, but that would not change the fundamental similarities in the underlying costs, nor should it change the regulatory methodology used to establish rates. Given the similarities in the cost structure, and the OEB's long history of applying index-based approaches to establish rates for natural gas and electric distributors, a hypothetical example to illustrate the impacts of index based price cap regulation appears unnecessary.

Question b)

Assuming that capital investment increases by inflation, under cost of service regulation the incremental depreciation and cost of capital on that investment reflected in the revenue requirement will increase by only a portion of the increase in capital investment. As a result, OPG confirms that under cost of service regulation:

1) Assuming that capital and operating costs increase by inflation, a cost of service-based revenue requirement will increase by less than inflation (however, OPG cannot confirm the 40% amount given its comments on the assumptions above);
2) Revenue requirement will increase at a rate closer to inflation as inflation-driven operating costs become a higher percentage of annual costs relative to capital, and vice-versa; and
3) Annual costs (i.e. revenue requirement) can only be equal to or greater than inflation if operating costs are 100% of annual costs, or operating costs or capital costs rise significantly faster than inflation.

OPG further notes that the generic confirmations above would apply to all utilities regulated under cost of service regulation.

SEC Interrogatory #101

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

Interrogatory

Reference:
[A1/3/2, Attach. 1, p.42]

Please explain why the output measures were not adjusted for hydrology to remove volatility. Please advise to what extent costs for a hydroelectric facility are independent of annual variations in hydrology.

Response

The following response was provided by LEI.

LEI did not adjust the annual generation data for hydrology for a number of reasons, some related to practical considerations and others related to conceptual factors. First, hydrology adjusted data was not readily available from peers other than OPG. Hydrology-adjusted or weather-normalized generation data are typically not published. In addition, the form of TFP methodology (an Index-based approach) does not lend itself to consideration for such factors to "control" for deviations in hydroelectric output. For example, in an econometric analysis, it is far easier to introduce explanatory weather variables, such as precipitation or snowmelt statistics. Finally, and most importantly, LEI accounted for the variability in hydroelectric output from year-to-year by using many years of data that are on average consistent with long run mean/median water conditions (please see page 18 of the LEI Report).

Regarding the second part of the question, hydroelectric facility costs are generally invariant to hydroelectric production, as most cost drivers are not related to the volume of electricity produced (except some wear and tear that may arise as a result of utilization of certain equipment). This lack of relationship over time between costs and hydroelectric output does not invalidate the use of annual electric generation as the proper measurement of output in the TFP study.

SEC Interrogatory #103

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

Interrogatory

Reference:

Please confirm that, assuming constant production, the gross revenue charge increases by the same percentage as the payments amounts for hydroelectric generation. Please confirm that, under the proposal from the OPG, the gross revenue charge would increase annually by the inflation factor, less the stretch factor.

Response

OPG's understanding is that IRM decouples costs and revenues; therefore revenues and costs do not escalate at the same rate. OPG's proposal is specific to revenue escalation, as contemplated by the 4GIRM price-cap index method in the RRFE. OPG has not proposed that the GRC increase by the inflation factor.

LONDON ECONOMICS

Selection of inflation indices for the I factor should be done on the basis of objective criteria

1. Relevance to utility costs

Does it closely reflect the utility's observed cost pressures?

2. Exogeneity

Is the utility a large component of the index?

3. Source reliability

Does the index come from a reliable source?

4. Data availability

Does the index rely on readily available, public data?

5. Index simplicity

Is the index generally accepted by ratepayers and easy to calculate and understand?

6. Index stability

Are the year-over-year changes in the index relatively stable and not overly volatile?

LEI recommends a composite inflation index for OPG's hydroelectric generation business under IRM

- **A composite inflation index is where an index is composed of other sub-indices for key inputs, which reflect different inflation trends for different cost categories**

$$I = \alpha\,(Labour\ inflation) + \beta\,(Non - labour\ inflation) + \delta\,(Capital\ inflation)$$

where α, β and δ represent weights

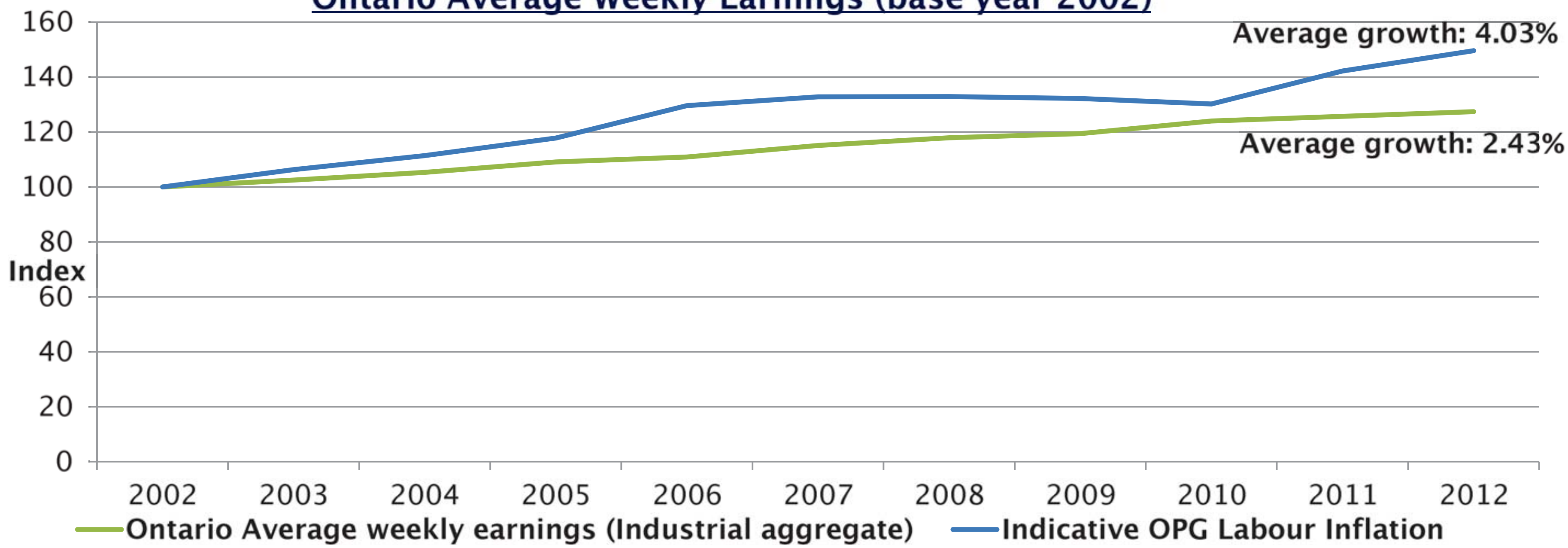
- **The criteria of relevance to OPG's unit cost pressures is best achieved with a customized inflation index**
  - OEB has concurred and recently modified its policies to utilities to propose customized input-focused inflation indices
- **A customized inflation index need not be complex, especially if there are publicly available indices available**
  - OEB has moved to a composite two-factor inflation index in 4G IRM for electricity distributors

The average weekly earnings index for the utility sector is a reliable and relevant measure of labour cost inflation

- LEI recommends Statistics Canada's average weekly earnings (AWE) index for Ontario industrial aggregate, which shows the average financial return from paid employment to inflate labour costs
- Average growth in OPG labour costs per FTE from 2002 to 2012 was 4.03%, which is greater than the average AWE growth rate of 2.43%

Criteria	AWE
1. Relevance to utility costs	✓
2. Exogeneity to the firm	✓
3. Data availability	✓
4. Source reliability	✓
5. Index simplicity	✓
6. Index stability	✓

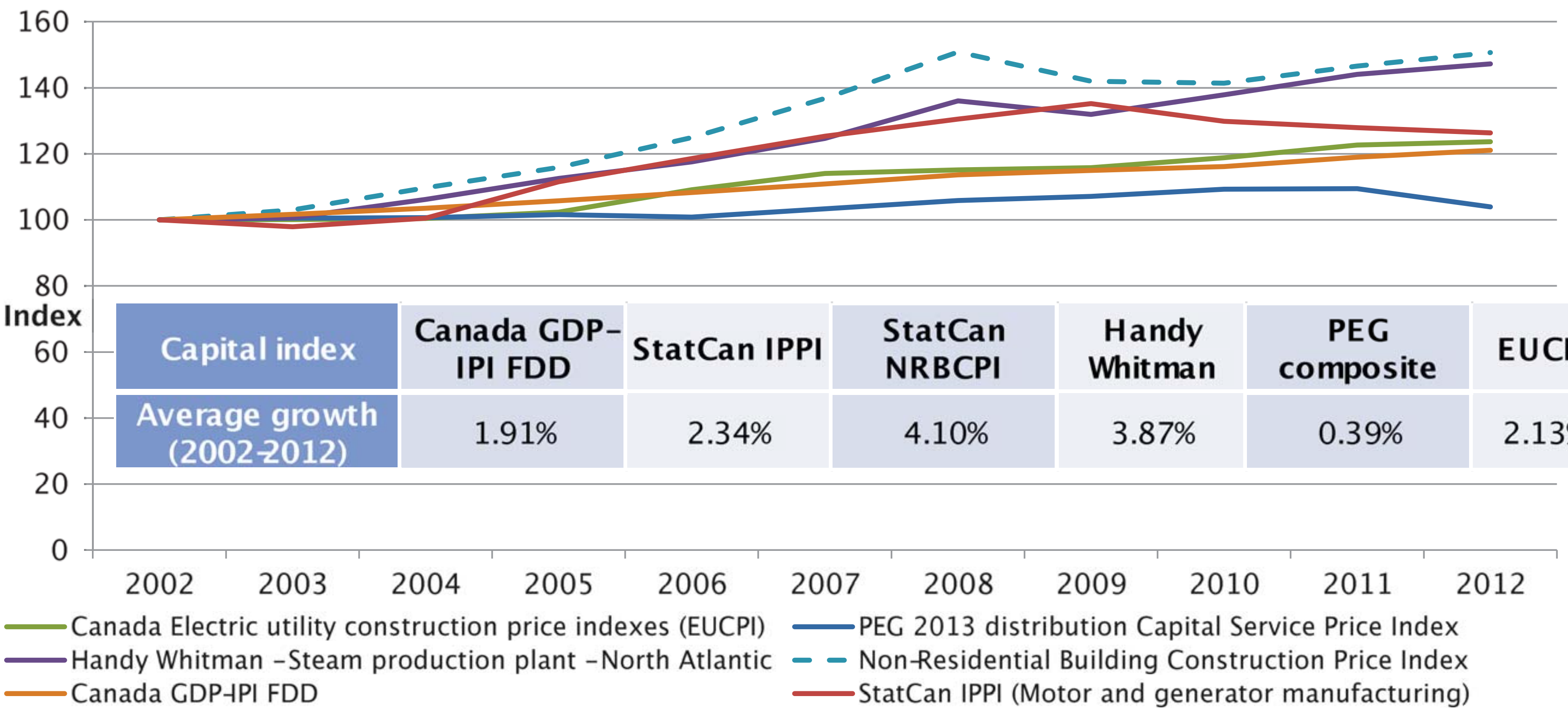
Ontario Average Weekly Earnings (base year 2002)



LONDON ECONOMICS

GDP–IPI FDD for capital inflation maintains exogeniety of the index, yields more stable rates, and is simpler for ratepayers to understand, while still being relevant to utility costs

- LEI evaluated a variety of options for the capital inflation index; relevance and exogeneity are the more important criteria – but simplicity, stability, data availability, and reliability are also important to consider
- Although a tailored capital index such as StatCan Industrial Product Price Index (IPPI) or Non–residential Building Construction Price Index (NRBCPI) are relevant to the key capital components of a hydroelectric generation business, historical data shows that such indices are sensitive to economic cycles



Capital index	Canada GDP–IPI FDD	StatCan IPPI	StatCan NRBCPI	Handy Whitman	PEG composite	EUCPI
Average growth (2002-2012)	1.91%	2.34%	4.10%	3.87%	0.39%	2.13%

UNDERTAKING JT3.16

Undertaking

IN RESPECT OF Ex. L-11.1-1 STAFF 247, TO PROVIDE PREVIOUSLY EXCLUDED DATA WITH RESPECT TO THE PRODUCTIVITY TREND OF OPG'S MANAGEMENT OF HYDROELECTRIC ASSETS

Response

OPG undertook to provide information as agreed in follow-up discussions with Mr. Ted Antonopoulos of OEB Staff, as referenced in the November 16, 2016 Technical Conference transcript at p. 92 lines 12-16. In addition, OPG has undertaken to either add nameplate values to Chart 6 of Ex. L-11.1-1 Staff-247 (Staff 247) or to provide the ratio of the maximum continuous rating to the nameplate capacity, if possible, as referenced in the November 16, 2016 Technical Conference transcript at p. 93 lines 6-8.

As agreed through the follow-up discussion with OEB Staff and in response to this undertaking, OPG provides the following supplemental information in connection with Staff 247:

1. An expanded version of Chart 1, including estimated data from OPG's inception in April 1999, filed as Chart 1A, below.

2. An expanded version of Chart 2, including estimated data from April 1999, filed as Chart 2A, below.

   OPG has adjusted the group of hydroelectric assets included in Charts 1A and 2A, in order to be consistent with Charts 3, 5, and 6. As described in parts (a), (b) and (e) of Staff 247, Charts 1 and 2 provided information on OPG's <u>currently regulated hydroelectric assets</u> over the 2002-2015 period. Charts 3, 5, and 6 were prepared on a different basis; they reflected all of OPG's <u>currently operating hydroelectric assets</u>, removing assets as they became subject to IESO contracts.[1]

   In order to provide a consistent set of data in this response, OPG has prepared Charts 1A and 2A on the same basis as Charts 3, 5, 5A, 6, and 6A (i.e., removing amounts for generation as it became contracted). Charts 1A and 2A include a column removing amounts for facilities that became contracted each year.

   During the Technical Conference, OEB Staff's consultant asked several questions related to the valuation of OPG's hydroelectric assets as acquired from Ontario Hydro at the time Ontario Hydro ended operations.[2] OPG notes that the valuation of OPG's assets was discussed in greater detail during the previous payment amounts

[1] The basis on which Charts 3, 5 and 6 were prepared is described in the response to parts d) and i) of Staff 247.
[2] EB-2016-0152, Technical Conference Transcript: November 16, 2016, pages 87-90.

application, EB-2013-0321, and refers OEB Staff to the transcript of that proceeding[3] and a related undertaking[4] for further background information.

3. An expanded version of Chart 5, including data from 1989, filed as Chart 5A, below.

4. An expanded version of Chart 6, including data from 1989, filed as Chart 6A, below. Chart 6A also includes the original nameplate capacity of OPG's hydroelectric generating stations, consistent with the other charts provided in this undertaking. As noted in OPG's response to part (i) of Staff 247, the nameplate capacity does not accurately reflect the capacity of the facilities. The nameplate capacity does not account for upgrades and other work that has affected stations' capacity since they were first put into service. The Maximum Continuous Rating values provided in Chart 5 represent the current, accurate capacity of OPG's hydroelectric assets.

5. Excerpts from the Ontario Hydro Statistical Yearbooks from 1989 to 1993, included as Attachment 1.

6. Excerpts from the Ontario Hydro Annual Reports from 1989 to 1996, included as Attachment 2.

   While OPG does not know which specific data OEB Staff plans to use from the Ontario Hydro Statistical Yearbooks and Annual Reports, it cautions that there are significant discontinuities between the data in those documents and OPG's own data as reported to the OEB in the current and in prior proceedings, beyond the asset valuation issue noted above. OPG identifies the following non-exhaustive list of discontinuities that may arise if OEB Staff were to rely on data from the Ontario Hydro documents:

   1. The hydroelectric capacities in the Statistical Yearbooks are measured as "dependable peak capacities," based on estimated stream flows (98% confidence level). These capacities can vary year over year depending on hydrological conditions and are not necessarily indicative of the physical capability of the equipment.

   2. The overall capacities reported in the Statistical Yearbooks are subject to two major, unusual adjustments: (i) a negative adjustment at Niagara and, (ii) an overall positive adjustment for "diversity of total system". OPG's data in Chart 6A does not reflect such adjustments.

   3. There are several plants in the Statistical Yearbook tables that have been either decommissioned or sold. For example, Ontario Power GS and Toronto Power GS have been decommissioned, and Aubrey Falls, GW Rayner, Wells and Red Rock Falls stations were sold in 2002.

[3] EB-2013-0321, Hearing Transcript: July 14, 2014, pages 130-138.
[4] EB-2013-0321, Undertaking J12.3.

4. The dependable peak capacity of Sir Adam Beck 1 is based on 10 units. Units 1 and 2 (25 cycle) are presently shutdown and their capacity is not included in the data set provided by OPG in the accompanying charts. The dependable peak capacity for DeCew Falls No.1 is based on 5 units (one unit was permanently shutdown, and the station now has 4 units).

Chart 1A
Continuity of Gross Hydroelectric Property, Plant and Equipment ($M)

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	Removal of Asset Upon Becoming Contracted	Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	1999[1]	7,216.5	49.9	-	-	7,266.4
2	2000	7,266.4	66.0	0.4	-	7,332.9
3	2001	7,332.9	60.5	0.5	-	7,393.9
4	2002	7,393.9	91.6	8.9	-	7,494.4
5	2003	7,494.4	39.3	23.6	-	7,557.4
6	2004	7,557.4	120.2	5.7	-	7,683.2
7	2005	7,683.2	58.0	28.1	-	7,769.3
8	2006	7,769.3	55.4	2.1	-	7,826.8
9	2007	7,826.8	83.5	(8.7)	-	7,901.6
10	2008	7,901.6	57.4	(14.6)	-	7,944.5
11	2009	7,944.5	97.1	(19.1)	(23.4)	7,999.0
12	2010	7,999.0	136.9	(12.6)	(43.7)	8,079.6
13	2011	8,079.6	134.6	(8.5)	(501.8)	7,704.0
14	2012	7,704.0	59.9	(13.7)	-	7,750.2
15	2013	7,750.2	1,559.1	(9.0)	-	9,300.3
16	2014	9,300.3	74.3	(85.6)	-	9,288.9
17	2015	9,288.9	71.2	(6.9)	-	9,353.2

[1]As estimated for the period from OPG's inception in April 1, 1999 to December 31, 1999. Subsequent material true-up adjustments to the April 1, 1999 asset valuation are reflected as of April 1, 1999 for continuity purposes.

Chart 2A
Continuity of Hydroelectric Accumulated Depreciation and Amortization ($M)

Line No.	Year	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	Removal of Asset Upon Becoming Contracted	Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	1999	-	(91.5)	-	-	(91.5)
2	2000	(91.5)	(119.6)	(0.3)	-	(211.4)
3	2001	(211.4)	(113.6)	(0.3)	-	(325.4)
4	2002	(325.4)	(115.4)	(2.8)	-	(443.5)
5	2003	(443.5)	(117.2)	(2.6)	-	(563.4)
6	2004	(563.4)	(120.0)	(0.1)	-	(683.5)
7	2005	(683.5)	(121.0)	(8.2)	-	(812.6)
8	2006	(812.6)	(121.1)	(3.0)	-	(936.8)
9	2007	(936.8)	(123.6)	3.4	-	(1,057.0)
10	2008	(1,057.0)	(125.0)	5.4	-	(1,176.5)
11	2009	(1,176.5)	(124.5)	8.0	4.4	(1,288.6)
12	2010	(1,288.6)	(126.1)	8.6	2.1	(1,404.1)
13	2011	(1,404.1)	(120.0)	3.1	92.5	(1,428.6)
14	2012	(1,428.6)	(121.3)	6.0	-	(1,544.0)
15	2013	(1,544.0)	(137.1)	4.9	-	(1,676.3)
16	2014*	(1,676.3)	(138.4)	8.9	-	(1,805.8)
17	2015	(1,805.8)	(138.2)	3.7	-	(1,940.4)

* Amount in col. (c) includes an adjustment to reduce the Niagara Tunnel Project in-service amount to the approve value per EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2.

Chart 5A
Total Hydroelectric Generation (TWh)

Years	Generation	Generation with PGS
1989	34.3	34.2
1990	35.6	35.5
1991	33.2	33.1
1992	35.3	35.2
1993	35.7	35.5
1994	34.7	34.5
1995	34.4	34.2
1996	36.3	36.2
1997	35.2	35.1
1998	31.2	31.1
1999	33.1	33.0
2000	34.1	33.9
2001	33.1	32.9
2002	33.9	33.8
2003	33.1	33.0
2004	35.3	35.2
2005	33.4	33.2
2006	34.2	34.0
2007	32.9	32.7
2008	37.4	37.3
2009	36.3	36.2
2010	30.5	30.4
2011	31.3	31.2
2012	29.5	29.4
2013	31.4	31.3
2014	31.5	31.4
2015	30.3	30.2

Chart 6A

Maximum Continuous Rating and Original Name Plate Capacity - Hydroelectric Facilities (MW)

Years	Generation Capacity / MCR	Original Name Plate Capacity
1989	6523	5775
1990	6523	5775
1991	6523	5775
1992	6523	5775
1993	6523	5775
1994	6546	5781
1995	6563	5783
1996	6642	5838
1997	6666	5838
1998	6718	5838
1999	6763	5838
2000	6813	5838
2001	6866	5838
2002	6899	5838
2003	6926	5838
2004	6958	5838
2005	6924	5787
2006	6971	5787
2007	6971	5787
2008	7015	5838
2009	6915	5725
2010	6906	5713
2011	6422	5284
2012	6422	5284
2013	6433	5284
2014	6433	5284
2015	6428	5284

1 Executive Summary

LEI reviewed the PEG Report and the responses to interrogatories filed by OEB Staff regarding the PEG Report, as filed on December 14, 2016. LEI has reached three conclusions regarding PEG's analysis:

1. **The PEG Report is based on assumptions that do not reflect the actual operating properties of hydroelectric generation assets.**

   PEG has employed an accounting standard of depreciation (geometric decay) that is fundamentally inconsistent with the actual, physical performance of hydroelectric generation assets. These assets do not experience physical depreciation in pre-set increments every year of their service life, as estimated by PEG. If they are properly maintained, these assets should operate consistent with their initial design and physical capability year after year. Indeed, OPG has assets that were built more than a hundred years ago, and they are continuing to operate at levels consistent with their design capability.

   The PEG Report also failed to account for other properties of hydroelectric generation assets. These assets do not benefit from fast-paced technology improvements, compared to assets in other infrastructure industries, as only the electrical and mechanical components can be replaced over time to improve productivity, while their civil structures (e.g. dams) remain largely unchanged. In addition, an accurate productivity study should reflect the fact that these assets produce more than electricity and ancillary services. Hydroelectric generators also provide dam safety and watershed management services, balancing energy production requirements with environmental, commercial and recreational needs.

   Finally, PEG has taken an approach that is inconsistent with how hydroelectric generating assets are paid. The OEB has consistently held that these assets are paid on the basis of their energy production, which implies that electric generation is a good proxy for other services that are produced. Moreover, the design of Ontario's energy market means that if these assets were not regulated, they would also be paid on the basis of energy production. If the TFP model that PEG proposes is used to calibrate the X factor in a price cap index, PEG's approach introduces risk of long-term capital insufficiency.

2. **The PEG Report is based on several methodological errors and omissions.**

   The TFP growth estimate in the PEG Report is biased given the assumptions made. The most important methodological error is the use of the geometric depreciation profile, as also discussed above. By way of the basic math, the use of this assumption in the PEG Report leads to an over-statement of the estimate industry average TFP growth rate.

   Since PEG's model explicitly excludes improvements in generation (MWh), it is unable to account for many productivity improvements that increase energy production but do not impact capacity. For example, PEG's methodology does not recognize any productivity impact from OPG's Niagara Tunnel Project, since that investment increased expected annual generation (MWh) but not capacity (MW) of the Sir Adam Beck generation facility.

3 Major issues

The two primary differences between LEI's TFP study and PEG's analysis are the approach taken for defining capital input quantities and output. There are multiple approaches for measuring capital input quantities, and none will be "perfect." PEG's analysis is based on an input measure that does not reflect the characteristics of the hydroelectric generation industry. The best approach is one that reflects the realities of the industry under study. LEI's physical proxy method accomplishes just that. Similarly, there are tradeoffs for selecting the output metric. PEG chose an output metric based on a conceptual assessment of the relationship between costs and outputs. In contrast, LEI's TFP study better reflects the actual services provided by hydroelectric operators and the practical realities of the market.

3.1 Measuring capital input quantities

TFP studies can use either a monetary or a physical approach to measure capital input quantities. The decision in favor of one approach over another requires evaluation using conceptual merits (e.g., which approach represents the industry best?) and practical merits (e.g., what data is available?). Both approaches have shortcomings and advantages.

Conceptually, the monetary method can include capital equipment of all kinds, which may be important if a business uses many different assets that cannot be unified easily by using non-financial measures. However, many more years of data are required and a depreciation assumption must be employed to approximate the capital input quantity. Therefore, a major weakness of a monetary approach is that, without depreciation assumptions that reflect the actual, physical depreciation profile of the assets, it can produce a misleading result.

In contrast, the physical method relies on physical measures of the quantity of capital deployed. In the electric generation industry, a physical method is straightforward, because the capital input quantity can be thoroughly represented by capacity ratings (in terms of MWs).[27] However, the usage of MWs on the input side of the TFP equation precludes using capacity sales (also measured in MWs) on the output side of the TFP equation.

Ultimately, the core issue is which method provides the best overall approximation to the actual quantity of capital input used each year and allows for the most realistic measurement of productivity, given the characteristics of the assets and industry in question. For the hydroelectric generation industry, where capital can be suitably measured using capacity ratings (in MW) and the physical decay in the capital assets over time is limited, the physical method is superior to the

[27] LEI used MCR for OPG and demonstrated maximum generating nameplate ratings of power plants from FERC Form 1. This metric shows the productive capability of the asset without exceeding design thermal limits. It is a dynamic measure that explicitly reflects the performance of the capital equipment because utilities routinely test their asset's performance to develop these numbers.

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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 (Revised):

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%.

With receipt of better information from OPG's updated response to SEC-095, PEG prepared Table 1 which shows that approximately 35% of the Company's capital spending during the IR term would be addressed by the CRVA. Table 2 shows that, for PEG's featured "larger" sample over the featured 1996-2014 sample period, removing 35% of the capex of sampled utilities while keeping all of the declining cost of older plant would cause the capital quantity index to average a -1.06% annual decline rather than a -0.48% annual decline. The average annual MFP growth rate rises by 45 basis points to 0.74%. Further detail of these calculations is presented in Attachment M2-11.1-SEC-1-Updated.

Table 1

Estimate of CRVA Plant Addition Share in Total Plant Additions

	Total CRVA Plant Additions*	Total Plant Additions*	% CRVA in total plant additions
2017	88	182	48%
2018	38	178	21%
2019	72	186	39%
2020	81.5	211	39%
2021	56.5	195	29%
Average for 2017-2021			35%

*As found in OPG's updated response to SEC-095.

Table 2

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

(Larger Sample with 35% Capex Reduction for CRVA)

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%	-2.08%	-5.09%	-2.58%	3.61%	1.81%
1998	0.14%	6.75%	-1.71%	-4.55%	-2.14%	2.28%	8.89%
1999	-0.60%	-15.88%	-2.08%	8.22%	-0.84%	0.23%	-15.04%
2000	0.13%	-10.53%	-1.96%	-12.08%	-2.21%	2.34%	-8.32%
2001	0.38%	-13.21%	-2.02%	5.90%	-1.71%	2.09%	-11.49%
2002	-0.66%	10.02%	-1.98%	-0.17%	-1.90%	1.24%	11.93%
2003	0.12%	17.89%	-1.89%	4.68%	-0.98%	1.10%	18.86%
2004	-0.18%	-9.60%	-2.02%	5.08%	-0.95%	0.76%	-8.65%
2005	0.44%	5.18%	-1.71%	1.92%	-1.16%	1.61%	6.34%
2006	0.20%	0.75%	-0.42%	-5.77%	-1.16%	1.37%	1.91%
2007	1.52%	-32.12%	-1.76%	11.18%	0.71%	0.81%	-32.83%
2008	-0.11%	3.23%	-1.47%	2.09%	-0.53%	0.42%	3.76%
2009	0.10%	22.18%	-1.28%	4.65%	0.40%	-0.29%	21.78%
2010	-0.01%	-2.04%	-1.36%	3.70%	-0.15%	0.14%	-1.88%
2011	0.09%	2.42%	-0.25%	0.94%	0.26%	-0.17%	2.16%
2012	-0.05%	-21.05%	-0.43%	0.14%	-0.28%	0.23%	-20.77%
2013	1.74%	8.48%	0.26%	0.56%	0.37%	1.37%	8.11%
2014	0.69%	-13.20%	1.16%	0.59%	0.69%	0.00%	-13.89%
Averages:							
1996-2014	**0.20%**	**-2.11%**	**-1.06%**	**1.52%**	**-0.54%**	**0.74%**	**-1.57%**

[1] 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.

<u>SEC Interrogatory #7</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.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.

<u>**Response:**</u>

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.

1.2 What data was used for the TFP study?

Based on best practices of estimating TFP for generation companies, and after considering issues related to data availability, LEI defined the TFP study output as generation in megawatt hours ("MWh"), and inputs as physical capital measured in megawatts ("MW"), as well as annual operations and maintenance ("O&M") costs measured in dollars and deflated by an appropriate index in order to isolate productivity trends.[4]

The data selection and gathering process was the most significant challenge in conducting the TFP study. Primary data sources include FERC Form 1, EIA, US BEA, US BLS, StatsCan, and company public reports, as well as data provided directly by OPG. The final TFP study includes sixteen (16) firms in total: OPG, thirteen (13) US investor-owned firms that file FERC Form 1 data, and two (2) US federal and municipal operators. Data for this study covered a thirteen year period from 2002 through 2014. [5]

1.3 What are the results of the TFP study?

For the industry consisting of OPG and 15 US peers, using data from 2002-2014, the TFP growth rate was estimated to be -1.01% per annum using the 'average growth' method. Under the 'trend regression' method, the industry TFP growth rate was estimated to be –1.18% per annum.[6] In comparison, the December 18, 2014 study reported a -1.02% industry TFP growth rate using 'average growth' method and -1.00% industry average TFP growth rate using the 'trend regression' method for the 2002-2012 timeframe. As explained further in Section 6.2.1, negative TFP results can be expected for mature hydroelectric businesses, because of fixed production assets, fixed production capabilities, and rising asset maintenance costs over time.

To determine these TFP figures, LEI used a Chained Fisher Ideal index method with a model consisting of two inputs (capital and O&M) and a single output (generation), as described further in Section 6.1.

1.4 How should the results of the TFP study be used for rate setting?

An industry TFP study measures the changes in overall productivity for a particular industry or peer group over a specified time period. Because an industry TFP study reports historical productivity growth rates, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically. An industry TFP is **not** a benchmarking study, as it does not focus on efficiency levels; therefore, it is important that TFP

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[4] See Section 4 for details on how this data is used and Section 4.2.1 for details on the deflation index.

[5] At the time LEI began this study, 2015 data was not yet available.

[6] See Section 3.2.2 for description of the two different methods of measuring TFP growth trends.

3 Basics of Total Factor Productivity

3.1 What is productivity?

Productivity is the ratio of the quantity of outputs produced by a firm, to the quantity of inputs used by the firm. Productivity growth is a trend variable, based on the year-on-year change in the productivity ratio, or the rate of growth in quantity of outputs relative to the rate of growth in the quantity of inputs. For purposes of IR, and specifically in the design of price caps and revenues caps, regulators are interested in changes in productivity over time. For example, historical productivity growth can inform regulators and the regulated utility on the level of productivity change, to guide the choice of an explicit productivity target or X factor under an I-X price cap or revenue cap.

Note that there are multiple methods for measuring productivity. In a practical sense, productivity measures the output quantity relative to input quantity, while productivity growth defines changes in this measurement over time. Common drivers of increased productivity include technological progress, economies of scale, and scope. When attempting to measure productivity, one would seek to capture as many drivers as possible. It should be noted that while TFP indexing techniques can be relied upon to measure total productivity, a TFP value cannot be decomposed to analyze the individual components or drivers of productivity.

There are also multiple categories of productivity that could be measured – for example, for assessing labour productivity, one would look at the ratio that represents the quantity of labour relative to the quantity of output. Labour productivity is a partial measure of productivity, also known as partial factor productivity ("PFP"). In contrast, a TFP measure would attempt to cover all types of inputs relative to all types of outputs.[12] The distinction between the TFP measure and the PFP measures therefore lies in the number of inputs analyzed – single factor productivity measures (or PFPs) relate output to a single input, whereas TFP considers output relative to all inputs. PFP measures can be misleading if considered in isolation.

Figure 2. Generalized concept of a TFP growth rate

$$\text{TFP growth rate} = \frac{\%\ \Delta \text{ weighted sum of the quantities of all outputs}}{\%\ \Delta \text{ weighted sum of the quantities of all inputs}}$$

An industry TFP study measures the changes in overall productivity for the firm and its peers over a specified time period – it is not a benchmarking study, as it does not focus on efficiency levels. In addition, an industry TFP study by definition will not focus on the regulated firm, but rather the industry as a whole. An industry TFP study is backward looking – reporting

[12] OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth.* 2001.

TFP index methods are deterministic and do not measure performance relative to an efficient frontier;[14] they measure the ratio of all outputs to all inputs, where input and output indexes are constructed using both quantities and prices of outputs and inputs. Traditionally, TFP indexing can be used to compare rates of change of productivity but not absolute levels (although more complicated multilateral index methods do also allow levels comparisons). The benefits of TFP indexing are that it is a relatively simple, easy to communicate, and robust technique that requires significantly fewer observations than the other measuring techniques, and thus it is often used for regulatory proceedings. TFP indexing is also more transparent when dealing with outliers, unlike DEA and econometric techniques. It is important to note that the TFP index method, because it is a numerical technique as opposed to a statistical technique, does not give a forecast error measure. Therefore, interpreting differences in index values requires qualitative considerations. Finally, LEI notes that the OEB and other regulators are familiar with the index approach,[15] and in the RRFE proceedings the Board stated its preference to continue to rely on productivity factors that were determined using the index-based approach.[16]

3.2.1 Selecting an indexing technique

The TFP index methodology requires selection of an indexing technique in order to calculate TFP growth rates. To determine which indexing technique was best suited for TFP calculations, LEI considered Diewert and Nakamura's 2005 review of the four most popular alternate index number formulations: Laspeyres index, Paasche index, Fisher Ideal index, and Törnqvist index (see Appendix B Section 9.1.1 for description of each index).[17] Diewert and Nakamura used the 'axiomatic' approach to the selection of an appropriate index formulation which specifies a number of desirable properties an index formulation should possess: constant quantities test, constant basket test, proportional increase in outputs test, and time reversal test. Only the Fisher Ideal index satisfied all four criteria that an index number method needs to meet.[18]

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[14] Deterministic methodologies "calculate" TFP values, as opposed to econometric methodologies which "estimate" TFP values. Non-frontier methods assume production is always efficient in their use of existing technology, and equates potential level of production at each moment in time. Non-frontier methods do not provide separate estimates of technical change and efficiency change. Further discussion regarding methods of measuring productivity can be found in Section 9.1.1.

[15] The TFP Index method has also been used in previous industry productivity studies before the OEB, and is a preferred method among practitioners for I-X regimes.

[16] OEB. *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. Issued November 21, 2013, corrected December 4, 2013.

[17] Diewert and Nakamura. *Concepts and Measures of Productivity: An Introduction.* 2005.

[18] It should be noted that these four index formulations generally produce very similar results.

Capital input share

Capital cost input shares may be estimated using two methods, an endogenous or an exogenous approach. The endogenous approach is the residual of revenue less operating costs (assumes prices are proportional to marginal costs and revenues are equal to costs); it is appropriate for competitive conditions or if a firm has been regulated for an extended period under a cost of service methodology such that revenues cover costs.

The exogenous approach is calculated by forming a user cost measure based on an estimated depreciation rate, a rate of return on capital, a deduction for the estimated rate of capital gains or addition for capital losses (i.e., annual change in the asset price index), and applied to a starting point asset value (capital stock). It recognizes that there has to be a "return of" capital over the asset's lifetime (i.e., the firm has to recoup its original investment) and a "return on" capital to compensate for holding the asset over its lifetime reflecting the opportunity cost of using the funds in an alternative investment. The exogenous approach must also consider that capital gains resulting from an increase in the price of the asset reduce the cost of holding (and using) the asset over the year. The exogenous approach also requires making a judgment on the firm's true opportunity cost of capital, and usually assumes geometric depreciation of capital.

LEI used the endogenous approach (revenue=costs) to determine capital input shares, as it is easier to implement and is expected to provide a reasonable approximation of capital inputs in the business.

Figure 14. Annual implied Capital to Total O&M shares for hydroelectric generation industry[36]

Year	Capital Share	O&M Share
2002	85%	15%
2003	88%	12%
2004	86%	14%
2005	88%	12%
2006	86%	14%
2007	82%	18%
2008	84%	16%
2009	78%	22%
2010	75%	25%
2011	76%	24%
2012	67%	33%
2013	75%	25%
2014	76%	24%
Average	80%	20%

Source: Based on LEI internal analysis, using data sources described in Section 5.2

[36] In general, changes in capital share were largely driven by year-over-year revenue fluctuations. Specifically, revenue from 2011 to 2012 declined by a rate of -34%, causing capital share for the industry as a whole to drop from 76% in 2011 to 67% in 2012. Lower market revenues are a function of volumes of sales (which may be affected by hydrological conditions) as well as wholesale market price conditions, which can be attributed to external drivers in the regional power markets, such as (but not limited) to gas prices, demand conditions, and aggregate supply. The capital shares have been adjusted from the original study to account for the removal of Alcoa from the peer group.

included in the original December 2014 TFP study, was excluded in this update as the company sold more than half of its portfolio in mid-2012 (generating capacity decreased to 217 MW) and is no longer aligned with peer selection criteria.[41] The final peer group selected, as summarized in Figure 15, includes sixteen (16) firms: OPG, thirteen (13) US investor owned firms that file FERC Form 1 data, one US federal operator (Southeastern Power Administration), and one US municipal operator (Seattle City & Light).

Figure 15. List of peers included in industry

Company	Average age of hydro fleet (2016)	Sum of hydro plants capacity (MW) 2014
Pacific Gas and Electric	55	3,567
Duke Energy Carolinas, LLC	48	2,859
Virginia Electric and Power	35	2,122
Idaho Power Company	56	1,695
Alabama Power	68	1,668
Southern California Edison Company	74	1,112
Georgia Power Company	64	1,071
PacifiCorp	71	1,016
Avista Corporation	68	921
Portland General Electric Company	62	889
Union Electric	71	904
Appalachian Power Company	58	840
South Carolina Electric & Gas Company	54	750
Ferc Form 1		
Seattle City & Light	61	1,929
Southeastern Power Administration	40	3,392
Federal and Municipal		
OPG	**66**	**6,433**

Source: Source: FF1 dataset, OPG, SEPA and Seattle annual reports, data provided directly by companies

[41] On June 29th 2012, Brookfield Renewable Energy Partners announced its agreement to acquire four of Alcoa Power Generating Inc.'s hydroelectric generating stations in Tennessee and North Carolina. This portfolio change is reflected in Alcoa's 2013 FERC Form 1 filing.

6.2 Industry TFP results

6.2.1 Industry TFP results using the average growth method

The results for the industry TFP study over the 2002-2014 period using the average growth method suggest a TFP growth rate of -1.01%, as summarized in Figure 23.

Figure 23. Key TFP study results using the average growth method

Average index growth rates (2002-2014)		
Input Index	Output Index	TFP Index
0.38%	-0.64%	-1.01%

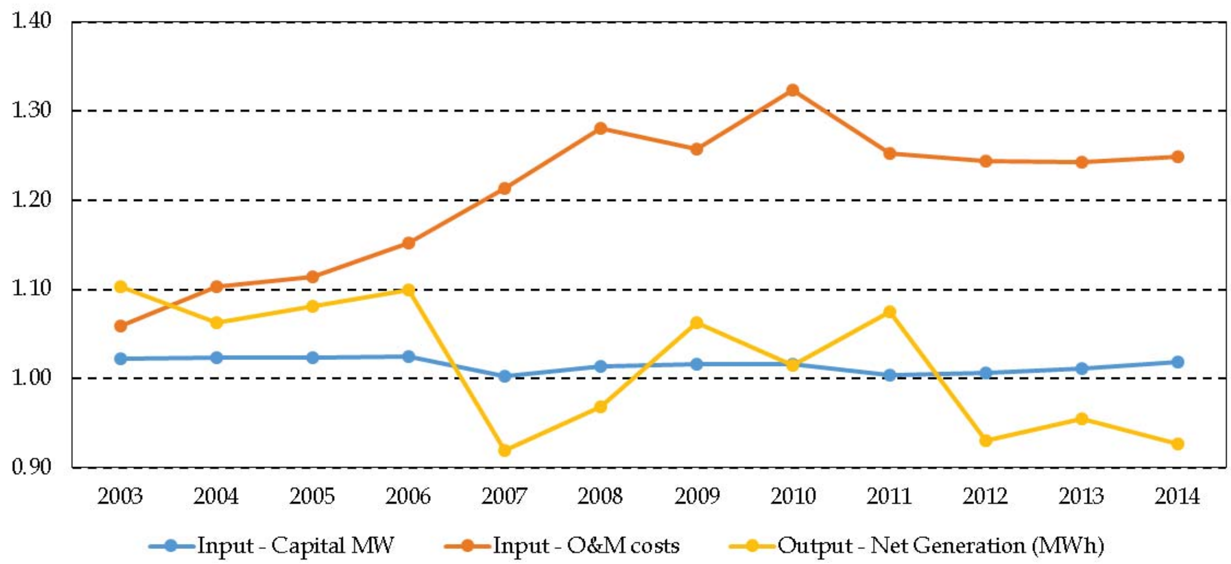

Figure 26, average growth rate for capital inputs measured in MW was 0.15% over the 2002-2014 period, with little year over year fluctuations. This result is to be expected for a mature hydroelectric industry as construction of new generation facilities is infrequent. O&M input growth was higher than capital input at an average rate of 1.85% over the study period, and year over year fluctuations were greater. LEI calculated capital's share of input for this peer set to be on average 80%, and O&M share of input to be 20% (see Section 4.2.2 for more background information on input shares); annual input weights are listed in Figure 24. With more weight assigned to capital, the total input index growth rate is estimated to be 0.38% using the average growth method, and year over year fluctuations are small, as seen in Figure 26.