IRM Design for Hydro One Networks, Inc.

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1. Introduction and Summary

1.1. Introduction

Hydro One Networks, Inc. ("Hydro One" or "the Company") filed a Custom Incentive Rate-setting ("Custom IR") application for its power distributor services on March 31, 2017. Escalation of the proposed revenue cap index is slowed by an X factor. The Company retained Mr. Steven Fenrick of Power Systems Engineering ("PSE") to prepare productivity and econometric benchmarking research and testimony in support the proposed X factor. PSE reported a total factor productivity ("TFP") trend of -1.4% for Hydro One over the 2003-2015 period and an average trend of -0.91% over this period for a broader sample of Ontario power distributors. Hydro One also commissioned unit cost benchmarking studies addressing various Company programs such as pole replacement, substation refurbishment, and vegetation management. The application was updated on June 7, 2017, including updated analyses by PSE.[1]

Hydro One is Ontario's largest power distributor. This increases the payoff from careful appraisal of its Custom IR proposal and supportive statistical cost research. Controversial technical work and IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for Hydro One and other Ontario utilities in the future. The Ontario Energy Board ("OEB") has commented on productivity and benchmarking methods in past IRM proceedings for all rate-regulated utility sectors.

OEB Staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on the productivity and benchmarking research and testimony and if necessary prepare alternative studies. We were also asked to appraise and comment on aspects of the Company's Custom IR proposal. This is the report on our work.

The plan for our report is as follows. We begin by providing pertinent background information. There follow critiques of PSE's productivity and benchmarking evidence and the presentation of some results using alternative methods. We conclude by discussing other features of Hydro One's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

[1] Further updates to the application were filed in October and December 2017, although these did not affect PSE's evidence or Hydro One's proposed rate adjustment plan.

1.2. Summary

Hydro One has proposed a Custom IRM that features a revenue cap index ("RCI") featuring a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. These proposals are supported by TFP trend and total cost benchmarking evidence prepared by PSE. PSE also attempted to update PEG's calculations for the Board, in the fourth generation IRM ("4th Generation IRM") proceeding, of the TFP trend of Ontario's power distribution industry. PSE calculated the TFP trend of Hydro One using an American Handy Whitman construction cost index.

Since this filing is being made towards the end of OEB's 4th Generation IRM plan, PEG understands the Company's (and the OEB's) interest in investigating whether productivity trends of Ontario power distributors have changed in recent years. In measuring the TFP of Hydro One and other distributors, a key issue is how to replace the Electric Utility Construction Price Index ("EUCPI") that Statistics Canada no longer calculates. Mr. Fenrick is a former employee of PEG and his methods are more similar to ours than those of some other productivity witnesses in recent IR proceedings.

PEG nonetheless disagrees with some of the methods PSE used in its productivity research. Here are our biggest concerns.

- We do not recommend using an American Handy Whitman index as the new asset price deflator in Ontario, preferring instead the implicit capital stock deflator for the Canadian utility sector. When our preferred deflator is used, Hydro One's recent historical TFP growth is found to be much slower.
- A study of the TFP trends of Ontario power distributors must control for their transition to International Financial Reporting Standards ("IFRS").
- PSE improperly updated the TFP indexes we developed for the OEB for 4th Generation IRM with respect to metering costs and contributions in aid of construction.
- The TFP indexes developed in 4th Generation IRM are due for methodological upgrades. In addition to a new asset price deflator, a new labor price index should be considered. A different output index is needed to calibrate the X factor of Hydro One's revenue cap index.

Our research using alternative methods suggests that Ontario's recent power distribution TFP trend is fairly close to zero. Growth in the productivity of operation, maintenance, and administration ("OM&A") inputs of Ontario distributors has been more brisk than growth in the productivity of capital inputs. The available evidence suggests that the 0.0% base TFP growth trend established in 4th Generation IRM is still reasonable.

PEG also has reservations about some of the methods PSE used in its benchmarking work. However, our alternative benchmarking runs with methods we prefer produced a similar benchmarking assessment. The total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark, on average from 2014-2016, but was improving, reaching 25.73% in 2016. Using our adaptations to PSE's model, we found that their performance continued to improve in 2017 and 2018. Hydro One's forecasted/proposed cost for the 2019-2022 period is 23.0% above the benchmarks. However, Hydro One has an incentive to understate its OM&A cost growth in the years after 2018.

On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor for the full plan term. Combined with the recommended 0% base X factor, this would give a combined X factor of 0.45%. The RCI formula would then be growth IPI - 0.45% for the annual adjustment of OM&A, net of Z factors or of any growth factor as discussed below.

The Custom IR plan proposed by Hydro One is, in several respects, uncontroversial. The design is similar to that of the Custom IR which the Board approved for Toronto Hydro in EB-2014-0016. The revenue cap index escalates OM&A revenue, strengthening the Company's performance incentives and avoiding the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside a deadband. A capital in service variance account ("CSVA") would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor ensures recovery of proposed/forecasted capital cost in each year of the plan, but this cost is reduced by the 0.45% stretch factor.

We are nonetheless concerned about some features of Hydro One's proposal. Here are some of our concerns and suggested alternative plan provisions.

- The proposed ratemaking treatment of capital cost is problematic. The C factor would incent Hydro One to exaggerate its need for supplemental revenue, and substantially raises regulatory cost for the OEB and stakeholders. The Company is perversely incented to spend excessive amounts on capital to contain OM&A expenses. The kinds of capex accorded C factor treatment are similar to those incurred by distributors in the productivity studies. The RCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for revenue growth even though it is designed to play neither of these roles. We discuss several possible upgrades to the capital cost treatment and conclude that a materiality threshold and dead zone should be added to the C factor mechanism.

- Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. We recommend a customer growth escalator.
- The addition of revenue decoupling to the plan has merit but makes less sense if the LRAM continues.
- With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. This raises oversight costs. Many utilities operating under IRMs do not have DVAs for these costs. Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism.

1.3. Credentials

PEG is an economic consulting firm with home offices in Madison, Wisconsin USA. We are a leading consultancy on IR and the measurement of energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry is the President of PEG. He has over thirty years of experience as an industry economist, most spent on utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity research and testimony in over 30 proceedings. His latest study on the productivity tends of US power distributors was published in 2017 by Lawrence Berkeley National

Laboratory ("Berkeley Lab").[2] He has played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. Dr. Lowry holds a PhD in applied economics from the University of Wisconsin.

[2] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background

Hydro One's proposed Custom IR plan is similar to that which the Board approved in 2015 for Toronto Hydro.[3] The term would be the five years from 2018 to 2022. A revenue cap index applicable to years 2019-2022 would feature two inflation measures: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all businesses in Ontario ("$AWE^{Ontario}$"). The RCI would also have a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. Several costs would be addressed by deferral and variance accounts ("DVAs"), including pension and other benefit expenses. A lost revenue adjustment mechanism ("LRAM") would expedite compensation for load losses due to conservation and demand management ("CDM") programs.

A Custom Capital Factor (aka "C Factor") averaging about 2% per year would supplement revenue growth to correct for the Company's expectation that the RCI would otherwise undercompensate it for growth in its capital revenue requirement. The capital revenue requirement would be based on forecasted/proposed cost but adjusted downward for the 0.45% stretch factor.

An asymmetrical earnings-sharing mechanism ("ESM") would share only surplus earnings. An asymmetrical capital in-service variance account ("CSVA") would reduce rates for the bulk of any plant addition underspends. Verifiable productivity gains would be excluded from the CSVA pass-through. In response to Staff interrogatory 123(b), the Company explained that

> Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.
>
> **All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.**
>
> Finance reviews all productivity reporting to ensure each initiative meets the following criteria:
>
> - Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
> - Auditable with an applicable baseline for reporting;

[3] EB-2014-0016

- **In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and**
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.[4] **[Emphasis added]**

[4] Exhibit I/Tab 25/Staff-123 b)

3. PSE Productivity Research

PSE calculated the total factor productivity trend of Hydro One over the 2003-2015 period.[5] It reported a -**1.4%** average annual growth rate (aka "trend") over the full sample period and a **-0.4%** trend in the five-year 2011-2015 period.[6] In response to an undertaking, PSE reported that Hydro One's productivity in the use of OM&A inputs averaged a 1.2% annual decline over the full sample period while capital productivity averaged a 1.5% decline. From 2011 to 2015, capital productivity growth averaged a 1.5% annual decline while O&M productivity growth grew at a brisk +2.0% annual pace.[7] In response to a data request, PSE also measured the TFP trend that is implicit in the Company's proposed cost of base rate inputs during the IRM. PSE reported that TFP will be about the same in 2022 as in 2015.[8]

Unexpectedly, PSE also calculated the TFP trend of a broader sample of Ontario distributors over the 2003-2015 period using a methodology similar to that which PEG used in its work for the Board to calibrate the X factor for 4th Generation IRM. PSE reported a **-0.91%** TFP trend over the full 2003-2015 sample period.[9] TFP declined substantially in all three years that PSE added to the sample.

PEG has reviewed PSE's direct evidence and working papers and has several concerns about the productivity research that PSE conducted. To facilitate the OEB's review of the complicated issues that arise in a productivity study, we highlight here our most serious concerns.

3.1. Asset Value Price Deflator

Power distributors use capital-intensive technologies, so the treatment of capital is a major issue when measuring their total factor productivity. TFP research in North America typically uses a "monetary" approach to capital cost and quantity measurement. Computation of capital quantity

[5] The TFP indexes PSE calculated for this proceeding are more accurately described as "multifactor" productivity indexes since they track trends in several kinds of inputs but exclude other inputs such as the power and upstream transmission services purchased in the provision of merchant services.

[6] Fenrick, S., Power Systems Engineering (PSE), *Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry*, EB-2017-0049, Exhibit A-3-2, Attachment 1, March 31, 2017, p. 2.

[7] HONI_TC_Undertakings JT1.01-1.07, Undertaking JT 1.3, March 14, 2018, p. 10.

[8] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I/Tab 8/Staff-31b, February 12, 2018.

[9] Fenrick TFP Study, *op. cit*., p. 4.

trends using monetary methods involves deflation of asset values that utilities report (e.g., their gross plant additions) using price indexes. Further discussion of monetary methods can be found in the Appendix.

PSE used an American Handy Whitman Electric Utility Construction Cost Index ("HWI") for power distribution in North Atlantic States to deflate Hydro One's asset values. They attempted to make this index more relevant to Canada by adjusting it for the trend in US/Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD"). However, like PEG in the 4th Generation IRM proceeding, PSE used Statistics Canada's Electric Utility Construction Price Index ("EUCPI") for distribution systems to perform the same function in its research on the TFP of other Ontario power distributors. This is to our knowledge the first time that an Ontario witness has proposed an alternative asset value price deflator in an energy utility productivity study. PSE's choice of an alternative deflator is an important empirical issue in this proceeding.

In response to an information request, PSE provided some criticisms of the EUCPI, including a statement that it didn't apply only to distribution (there were in fact EUCPI sub-indices calculated for "distribution systems" and "substations") and a concern that the EUCPI includes financing costs (there are versions without financing costs and the trends of these indexes are similar).[10]

The HWI has tended to grow much more rapidly than the EUCPI, so use of the HWI to deflate plant values should reduce measured capital quantity growth and accelerate TFP growth. In response to another information request, PSE reported that the TFP trend of the Company was a substantial 90 basis points slower (more negative) if the EUCPI was instead used as the asset value price deflator for the Company's productivity calculation.[11]

The appropriate asset price deflator to use in power distributor productivity research is an issue of growing importance in North American IR. One reason is that Statistics Canada stopped computing EUCPIs after 2014. We also believe that HWIs are due for a critical review.

Since, additionally, PSE used an HWI in its research, PEG has spent considerable time and effort in this project reviewing alternative asset price deflators. We found that HWIs and EUCPIs both have drawbacks. Both were designed many years ago and have some cost-share weights and inflation

[10] Exhibit I/Tab 10/SEC-17.

[11] Exhibit I/Tab 10/SEC-15.

subindexes that are now quite dated. The labor price component of the distribution system EUCPI has for many years grown quite slowly. However, trends in prices of labor and other construction inputs in the North Atlantic states, with their many large urban areas, may not be appropriate for Hydro One and other Ontario utilities.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario productivity research is Statistics Canada's implicit price index for the capital stock of the Canadian utility sector.[12] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from the Annual Capital Repair and Expenditures Survey. Mr. Fenrick stated at the technical conference that he did not consider alternative deflators in his work for this proceeding.[13]

3.2. Ontario Industry Productivity Research

PSE's -0.91% TFP trend estimate for the broader Ontario sample from 2003 to 2015 is disappointing if true and would imply that Hydro One's proposed revenue cap index contains a sizable implicit stretch factor. By way of contrast, we reported a **0.23%** trend in the TFP of US power distributors over the 2001-2014 period in our 2017 study for Berkeley Lab.[14] OEB Staff have not commissioned an updated study of productivity trends of power distributors since the 4th GIRM proceeding. Acknowledgment by the Board of a -0.91% trend in this proceeding could complicate a future proceeding on 5th Generation IRM for provincial power distributors.

There are, furthermore, reasons to doubt the accuracy of PSE's -0.91% trend estimate and its relevance for calibration of Hydro One's X factor. Here are some important grounds for concern that the -0.91% estimate may be too low. The biggest driver of the result was TFP declines in excess of 4% in 2012 and 2013. These were chiefly due to sharp declines in *OM&A* productivity. Over the full sample

[12] Statistics Canada, Table 031-0005, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

[13] Transcript, OEB, EB-2017-0049, HONI_Technical Conference_Day 1_20180301, p. 30, line 21 to p.31, line 1.

[14] Mark Newton Lowry, Matt Makos, and Jeff Deason, *op. cit.*, p. 6.4.

period, OM&A productivity growth averaged only -0.8% annually despite widespread installation in Ontario of automated metering infrastructure ("AMI") that should have cut OM&A costs.[15] Our Berkeley Lab study found that the OM&A productivity of US power distributors averaged 0.40% annual growth from 2001 to 2014 while capital productivity growth averaged 0.18%.

One reason for the negative OM&A productivity growth in Ontario in recent years which PSE reports has been the adoption by many distributors of new accounting standards. The OEB undertook the necessary work to determine how IFRS should be implemented and the result was a modified IFRS ("MIFRS"). The new standard affected a wide range of issues, but the most important item that impacts this productivity work is the treatment of capitalized overheads. Under Canadian GAAP, distributors were permitted to capitalize more costs than are permitted under IFRS. Not all distributors adopted MIFRS at the same time, and adoption often coincided with cost of service rate applications. Adoption of the OEB's revised capitalization policy sometimes predated full adoption of MIFRS. PSE noted, in response to a data request, that it did little work to gauge the impact of this conversion on productivity results.[16]

PSE used data from the OEB's total cost benchmarking program for its 2013-2015 Ontario productivity update even though these data include contributions in aid of construction ("CIAC") while those for the 4th Generation IRM productivity study did not. This will also tend to slow TFP growth artificially.

Average weekly earnings in Ontario were used in PSE's labor price index, as in PEG's 4th Generation IRM research. There are reasons to believe that this index is inexact. Trends in average weekly earnings are sensitive to trends in overtime and the composition of the labor force such as the share of employees working part-time. This creates aggregation bias in the measurement of labor price trends. A *fixed weighted* index of average hourly earnings of all employees in Ontario is available from Statistics Canada which is less biased.[17] We believe that this alternative labor price index should be used

[15] Exhibit I, Tab 8, Staff-33.

[16] Exhibit I/Tab 8/Staff-27a.

[17] Statistics Canada. Table 281-0039 - Survey of Employment, Payrolls and Hours (SEPH), fixed weighted index of average hourly earnings for all employees, by North American Industry Classification System (NAICS), monthly (index, 2002=100), CANSIM (database).

in any future Ontario productivity research. This would be more accurate and incidentally grow more rapidly, modestly increasing OM&A and total factor productivity growth.

The output indexes that PEG developed in the 4th Generation IRM proceeding and PSE used in its calculations are multidimensional, and summarize trends in distributor delivery volumes, peak demand, and the number of customers served using cost elasticity weights drawn from our econometric total factor productivity research for the OEB. Growth in volumes and peak demand have been slowed considerably in Ontario by CDM programs encouraged by government policies. The recent growth in system use may well be slower and increase capacity utilization less than was expected when many facilities were built. It may take time for slower growth in system use to produce material distribution capex economies.[18]

We note in the Appendix that elasticity-based scale indexes are useful when the goal of productivity research is to measure cost efficiency trends. However, as Mr. Fenrick notes in his report, the output index developed in 4th GIRM excludes other pertinent measures of output which drive cost. He developed a scale index that also encompasses trends in reliability and safety and describes this work in his productivity report.[19] The enhanced scale index is used to compute "adjusted TFP" results for Hydro One which he discusses on pp. 36-39 of his report. PSE found that the addition of reliability and safety variables to the scale index accelerated the estimated TFP trend of Hydro One over the full sample period by a substantial 90 basis points. We believe that system capabilities that depend on smart grid facilities (e.g., the quality of metering and the ability of distribution systems to handle 2-way power flows) are also legitimate candidates for inclusion in an elasticity-weighted output index. Thus, the scale indexes Mr. Fenrick uses to measure the productivity trends of other Ontario distributors are not ideal for measuring cost efficiency trends.

It is also unclear how appropriate the unadjusted scale index is for an X factor calibration exercise. Hydro One proposes a *revenue* cap index. We explain in the Appendix that the X factors of RCIs are typically calibrated with productivity indexes that use the number of customers to measure output.

[18] It may, alternatively, be the case that many distributors have not trimmed capex to reflect lowered expectations of future system capacity utilization.

[19] Fenrick TFP Study, *op. cit.*, pp. 28-34.

Most other distributors in Ontario operate under *price* cap indexes. Scale indexes used in X factor calibration exercises for price caps should in principle be revenue-weighted. Usage variables sometime receive substantial weights in revenue-weighted indexes. However, Ontario power distributors are transitioning to more fully fixed rate designs for residential customers that cause revenue to be driven increasingly by customer growth. Ontario power distributors also have LRAMs to compensate them for load impacts of CDM programs. Thus, the scale indexes Mr. Fenrick uses to calculate productivity trends of Ontario power distributors may also be inappropriate for determining X factors in future price cap IRMs.

Some other concerns that we have about PSE's Ontario industry productivity research are also important but do not necessarily suggest a higher or lower Ontario TFP trend.

- The EUCPI must be replaced and our research suggests that it has grown too slowly in recent years. Alternative asset value deflators we are considering have grown quite a bit more rapidly than the EUCPI in *recent* years and this could slow recent TFP growth. However, the trend of these alternative indexes in *earlier* years (e.g., before 2002) also affects TFP growth. The net effect on TFP is an empirical issue that we address further below.
- Pension and other benefits expenses are included in PSE's calculations (as they were in PEG's 4th GIRM research), even though these expenses would be Y factored in Hydro One's proposal and Statistics Canada does not maintain a labor price index that includes pension and benefit expenses. It is difficult to properly remove these expenses from the data. One reason is that the OEB has never provided PEG with itemized data on these expenses from the RRR for the full sample period which would be needed to remove them from the study. We are also concerned that some distributors do not consistently itemize these expenses in their reports to the OEB.
- PEG's productivity work in the 4th Generation IRM proceeding excluded all costs of Ontario's extensive AMI buildout, which began in 2007 and ended in 2012. We adjusted reported metering expenses for 2007 and later years to remove those attributable to AMI. These expenses grew over time to constitute almost all metering OM&A expenses by 2012. PEG also removed all reported metering capex for 2007 and later years.

  PSE's productivity update, which started with 2013 data, included all metering and meter reading expenses, causing thereby an artificial surge in OM&A expenses. This is another reason for the plunge in OM&A and total factor productivity in that year. PSE also included all metering capex starting in 2013. Capital costs of AMI installed between 2007 and 2012 were, however, excluded from Mr. Fenrick's productivity research.

If not now, it will soon be time to incorporate the full cost of AMI into calculations of the productivity trends of Ontario power distributors. This complicated exercise is beyond the scope of this project. In any event, it is not clear what the *net* impact of this inclusion would be. Inclusion of AMI capex would accelerate the industry's capital quantity growth from 2007 to 2012, especially if the cost of the older meters is not removed as they were replaced. However, capital quantity growth would be slowed after 2012 if properly measured since the AMI assets, with their relatively short service lives, would briskly depreciate. Metering OM&A expenses would have a more positive trend were they included for all years, and this would also slow TFP growth. However, they would not surge in 2013 as they do in PSE's treatment. Output quantity growth would accelerate were the scale index revised to reflect improved metering capabilities.

- Exclusion of Haldimand and Woodstock from PSE's study of the Company's productivity means that the study does not reflect all distributor operations of Hydro One. The impact of this is not expected to be large.

3.3. Alternative Productivity Runs - Ontario

We did not undertake a full upgrade and update of our Ontario power distribution productivity work for this proceeding. Many issues are best resolved in the upcoming 5th Generation IRM proceeding. However, PEG has undertaken preliminary work to quantify the impact of some of the issues noted above. Starting with the results in the PSE working papers, we introduced adjustments step by step to test the robustness of PSE's productivity results.

Table 1 provides the estimated incremental and cumulative impact of our adjustments on the OM&A, capital, and total factor productivity trends of sampled Ontario distributors over the full 2003-2015 sample period. The table is divided into an area for adjustments and corrections for known inconsistencies with our previous work and another area for upgrades to the methods we used in the 4th Generation IRM proceeding.

Here is a list of adjustments and corrections that we made to PSE's calculations.

- Contributions in aid of construction were removed from data for 2013-2015.
- Smart meter OM&A and capital costs were also removed.

Table 1

Analysis of PSE's Ontario Productivity Study

	OM&A Incremental Impact	OM&A Revised Trend	Capital Incremental Impact	Capital Revised Trend	TFP Incremental Impact	TFP Revised Trend
PSE Productivity Trend (2003-2015)		-0.83%		-0.96%		-0.91%
Adjustments and Corrections						
Data Comparability Issues						
CIAC	na	-0.83%	0.17%	-0.79%	0.09%	-0.82%
Smart Meter OM&A	0.21%	-0.62%	na	-0.79%	0.09%	-0.73%
Smart Meter Capital	na	-0.62%	0.08%	-0.71%	0.05%	-0.68%
Transition to IFRS Accounting Changes	0.82%	0.20%	na	-0.71%	0.35%	-0.33%
Sample and Merger Issues	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Exclude Norfolk	0.00%	0.20%	0.00%	-0.71%	0.00%	-0.33%
Include Lakeland/Parry	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Total Impact of Adjustments and Corrections [A]	**1.02%**	**0.19%**	**0.26%**	**-0.70%**	**0.58%**	**-0.33%**
Methodological Upgrades						
Labor Price Index [B]	0.12%	0.31%	na	-0.70%	0.05%	-0.29%
Asset Price Index: Replace EUCPI	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Utility Sector Capital Stock Deflator [D]	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Northeast HW index adjusted for PPP	na	0.31%	1.30%	0.60%	0.79%	0.51%
Output Quantity Adjustment	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Conservation adjustments to volumes and peaks	0.50%	0.81%	0.50%	-0.11%	0.50%	0.25%
Customer only index [C]	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Total Impact of Proposed Upgrades [E]=[B+C+D]	**0.42%**		**0.39%**		**0.38%**	
Total Impact of All Adjustments and Upgrades [A+E]	**1.44%**	**0.61%**	**0.65%**	**-0.31%**	**0.96%**	**0.05%**

- An adjustment was made for the transition to MIFRS accounting. We estimated the 2015 OM&A quantity in the absence of MIFRS transitions. Most companies that recently filed for rebasing have reported the amount by which their OM&A expenses were affected by MIFRS adoption. We were able to identify 14 distributors that clearly identified the impact. These companies as a group showed 12.5% higher OM&A expenses under MIFRS. We then attempted to identify distributors that had either adopted MIFRS by 2015 or indicated that they had previously changed their capitalization policy. We found that companies representing about 81% of OM&A cost had done so. As an adjustment, we therefore used an estimate of what the OM&A input quantity would have been in 2015 in the absence of MIFRS. Our 10.1% markdown is the product of a typical 12.5% reported increase in cost times 81% of costs affected by this issue.

- Adjustments were also made for two mergers.

Here is a list of the changes in our 4th Generation IRM methodology for measuring TFP which we considered.

- We replaced the AWE with the fixed-weight average hourly earnings in Ontario.
- We replaced the EUCPI in turn with two alternative deflators: the implicit price index for the capital stock of the utility sector from Statistics Canada and the Handy Whitman Index of Electric Utility Construction Costs for power distribution in the North Atlantic states.
- We considered replacing the elasticity-weighted output index developed for 4th Generation IRM with 1) the number of customers served and 2) an alternative elasticity-weighted index that includes CDM savings.

As can be seen in the above table, the impact of these issues on the TFP trends of Ontario power distributors varied in importance. Considering first the adjustments and corrections, the correction for the transition to IFRS accounting had the greatest impact. For the full sample period, the OM&A productivity trend accelerated by 82 basis points and the total factor productivity trend accelerated by 35 basis points. While based on valid concerns, adjustments for CIAC and the treatment of meters individually had smaller impacts on the TFP trend. Corrections for two mergers had very little impact. Taken together, all of these steps changed the estimated Ontario distributor TFP trend from -0.91% to -0.33% over the full sample period.

The impacts of the methodological upgrades on the TFP trend also varied. Use of the fixed-weighted labor price index for Ontario raised the OM&A productivity trend by 12 basis points and the TFP trend by five basis points.

Use of the implicit price deflator for the utility sector capital stock instead of the EUCPI raises the TFP trend by 4 basis points.[20] This leaves us at **-0.25%**. This is our best current estimate of the cost efficiency trend of Ontario power distributors. However, other drivers of cost such as reliability, safety, and metering capabilities are excluded from the analysis. If the number of customers were used to measure output, it can be seen that the output and TFP trends would be about 30 basis points higher.[21]

Taken together, our recommended methodological upgrades changed the Ontario TFP trend from -0.33% (after our corrections) to +0.05%, which is an increase of 0.38%. The +0.05% result is similar to the trend in the productivity of US power distributors over a similar period which we reported in our Berkeley Lab study. The total impact of corrections *and* improvements is to move the TFP trend from -0.91% to +0.05%, an increase of 96 basis points after rounding.

It is also interesting to compare the partial factor productivity indexes of OM&A inputs and capital. It can be seen that, after adjustments, corrections, and recommended methodological changes, the **+0.61%** growth trend in the OM&A productivity of Ontario distributors has been much more brisk than the **-0.31%** growth trend in the productivity of capital inputs. Our study for Berkeley Lab also found that the OM&A productivity growth of US power distributors exceeded their capital productivity growth, although by a smaller amount.

In summary, PSE's productivity evidence for Hydro One opens a complicated set of issues on how Ontario power distributor productivity research should be updated and methodologically improved. Our critique and alternative runs suggest that the TFP trend of Ontario power distributors has been much more rapid than -0.91%. However, finalization of many of these issues must await a future 5th GIRM proceeding. We recommend that the OEB not embrace PSE's -0.91% TFP trend estimate in this proceeding. The base TFP growth target of 0% that the Board established in 4th Generation IRM, and which Hydro One proposes, still seems reasonable pending more definitive research on Ontario industry TFP trends.

[20] It can also be seen that a PPP-adjusted Handy Whitman Index would produce a much larger increase in the Ontario TFP trend, but we are not suggesting that this would be an improvement in the accuracy of the index. We note this result because PSE used a Handy Whitman Index in its Hydro One-specific productivity work.

[21] Adding the impact of CDM on system use had an even larger effect. According to the Ontario Ministry of Energy, the impact of conservation and load control programs has approximately doubled since the 2012 endpoint of the previous study. Should the MW and MWh be adjusted to add back the impact of these programs, the output and TFP trends would be approximately 0.50% higher than measured by PSE.

3.4. Alternative Productivity Runs – Hydro One

We also recalculated the productivity trends of Hydro One. We revised PSE's methodology to use the implicit price deflator for the utility sector capital stock and the fixed-weight average hourly earnings for Ontario. Results of this work are presented in Table 2. It can be seen that the Company's TFP growth declined at a 2.31% average annual growth rate over the full 2003-2015 sample period. This result is quite different from PSE's, and less favorable to Hydro One. Output grew at a sluggish 0.6% average annual rate while input growth averaged 2.9%. OM&A productivity averaged a 1.11% annual decline while capital productivity averaged a more substantial 3.03% annual decline. In the last five years of the sample Hydro One's TFP growth improved, averaging a 1.26% decline. OM&A productivity growth averaged 1.93% annually whereas capital productivity declined by a substantial 3.2% annually.

Table 2

Adjusted Hydro One Productivity Results

					Productivity					
	Input Quantity (PEG Upgrade)			Output	PEG Upgrade			PSE Methodology		
Year	Summary	OM&A	Capital	Quantity[fn]	TFP	OM&A	Capital	TFP	OM&A	Capital
2003	1.5%	-1.2%	3.2%	1.6%	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	-0.8%	-6.3%	2.4%	0.7%	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	3.4%	5.8%	2.0%	1.2%	-2.2%	-4.6%	-0.8%	-1.5%	-4.3%	0.0%
2006	6.1%	10.2%	3.6%	0.3%	-5.8%	-9.9%	-3.2%	-4.8%	-10.4%	-1.8%
2007	9.9%	16.2%	5.6%	1.0%	-9.0%	-15.3%	-4.6%	-7.2%	-15.3%	-2.4%
2008	0.6%	-4.6%	4.2%	0.6%	0.0%	5.2%	-3.6%	0.7%	4.6%	-1.6%
2009	5.0%	5.6%	4.6%	0.0%	-5.0%	-5.6%	-4.6%	-4.1%	-6.7%	-2.8%
2010	4.0%	4.2%	3.8%	0.4%	-3.5%	-3.7%	-3.4%	-2.3%	-3.8%	-1.6%
2011	1.4%	-1.2%	3.2%	0.5%	-1.0%	1.7%	-2.7%	-0.1%	1.5%	-1.0%
2012	0.2%	-4.0%	2.9%	0.5%	0.3%	4.5%	-2.4%	1.1%	4.5%	-0.7%
2013	6.3%	8.4%	4.8%	0.2%	-6.1%	-8.2%	-4.6%	-4.6%	-8.1%	-2.7%
2014	3.2%	3.7%	2.9%	0.0%	-3.2%	-3.7%	-2.9%	-2.1%	-3.5%	-1.4%
2015	-2.9%	-14.6%	4.0%	0.7%	3.6%	15.4%	-3.3%	3.9%	15.3%	-1.6%
2003-2015	**2.9%**	**1.7%**	**3.6%**	**0.6%**	**-2.31%**	**-1.11%**	**-3.03%**	**-1.45%**	**-1.25%**	**-1.49%**
2003-2010	**3.7%**	**3.7%**	**3.7%**	**0.7%**	**-2.97%**	**-3.00%**	**-2.93%**	**-2.12%**	**-3.25%**	**-1.51%**
2011-2015	**1.6%**	**-1.6%**	**3.6%**	**0.4%**	**-1.26%**	**1.93%**	**-3.20%**	**-0.36%**	**1.95%**	**-1.47%**

[fn] The output measure for these calculations was the multidimensional elasticity-weighted output index developed by PEG for the OEB in 4th GIRM.

4. Benchmarking Research

4.1. PSE's Total Cost Benchmarking

PSE also benchmarked the total cost of the Company's distribution base rate inputs. This study appraised Hydro One's historical costs over the 3-year 2014-16 period and its forecasted/proposed costs for the 2017-2022 period. An econometric cost model was used in the study with parameters PSE estimated using US data on power distributor operations of investor-owned utilities ("IOUs") and rural electric cooperatives ("RECs"). This model has a flexible translogarithmic ("translog") functional form that includes quadratic and interaction terms for the output variables.

PSE reported that Hydro One's cost was 24.7% above the model's prediction on average from 2014 to 2016. Its proposed costs during the years of the IRM were about 22.2% above the model's predictions on average. On this basis, and in conformance with the OEB 4th Generation IRM rules, Mr. Fenrick advocated and the Company embraced a fixed 0.45% stretch factor during the years of the plan. Cost performance would decline about 1.3% between 2018 and 2022.[22] Hydro One's component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capital *expenditures* ("capex") were not separately benchmarked.

We have a number of concerns about PSE's benchmarking study. We highlight first our biggest concerns to facilitate OEB review.

- PSE's benchmarking results are improved by an optimistic forecast of Hydro One's OM&A expenses. These expenses appear to have been forecasted using an inflation – 0.45% formula that includes no growth factor. In addition, the PSE work assumed OM&A input price growth of 2.26%. This would overstate future cost performance if the 2.26% figure is more rapid than the inflation assumption used to generate the cost forecast. It is noteworthy that Hydro One has an incentive to understate its OM&A cost growth for the out years of the IRM because this reduces the stretch factor under its proposal without affecting the base productivity trend or C factor.

[22] Fenrick, S., Power Systems Engineering (PSE), *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network*, Exhibit A-3-2, Attachment 2, June 7, 2017, p. 6.

- The challenge posed by low customer density is a major issue when benchmarking the cost of Hydro One. The customer density variable that PSE used is service territory area/customer.[23] Service territory area is difficult to calculate accurately. A threshold issue in these calculations is whether the territory is the area which the utility must *stand ready* to serve if demand arises or the (often much smaller) area it *actually* serves. The former approach is easier to implement but less accurate. In the technical conference, Mr. Fenrick stated that PSE took the former approach.[24] Hydro One's customer density is reported to be far lower than the average for the rural electric cooperatives in the sample. The service territory estimate for Hydro One exceeds the entire land area of Ontario. Alternative density variables are available. PEG used overhead line miles per customer as the density variable in a recent power distributor cost benchmarking study for Alberta's Utilities Consumer Advocate ("UCA").[25] The value of this variable will tend to be high for distributors serving rural areas and low for distributors serving urban areas.

- One cost *advantage* of a rural distributor is extensive overheading of facilities, which saves on capital cost. Our research indicates that distributors with extensive overheading tend to have lower capital cost and total cost. There is no overheading variable in PSE's model.

- The PSE benchmarking study is unusual for including data from numerous US regional electric cooperatives in the sample, yet it excludes data for Ontario distributors that serve rural areas (e.g., Algoma Power) and report their costs in Canadian currency. REC data do have some advantages in a study of the cost performance of Hydro One.

    - RECs typically have low customer density like Hydro One. Inclusion of REC data in the sample to that extent increases the precision of forecasts of the cost of Hydro One. REC data are particularly desirable for estimating the parameter of the cost model's density variable.

    - Data on peak loads of RECs may be better than those available for US IOUs.

The REC data also have noteworthy limitations. Three of these are especially important.

[23] Fenrick, Benchmarking Study, *op. cit*., p. 11.

[24] Transcript, Technical Conference, March 1, 2018, *op. cit.*, p.46, line 17-p.47, line 4.

[25] Pacific Economics Group Research (2018). *Benchmarking the Performance of Alberta Power Distributors*, for Utilities Consumer Advocate of Alberta, February 2018.

- RECs tend to be much smaller than Hydro One.
- REC data are publicly available only through 2011. Inclusion of REC data in the sample to that extent reduces the precision of the trend variable parameter and of cost forecasts for years after 2011. This makes these data less relevant for calculating cost benchmarks for Hydro One in future years. Five years from now, in a possible new benchmarking study, this limitation of REC data would loom even larger.
- Pension and other benefit expenses of RECs are not itemized, so it is necessary to include these expenses for all companies in the benchmarking study, even though itemized data on these expenses are available for Hydro One and the American IOUs. PEG usually excludes pension and other benefit expenses from its benchmarking studies (but did not exclude them from our 4th GIRM study) because they are sensitive to volatile external business conditions that are beyond the control of utility managers.[26] Additionally, Hydro One proposes continuation of existing DVAs for these expenses.[27] We mentioned above that Statistics Canada does not have a labor price index that includes pension and benefit expenses.[28]
- Mr. Fenrick noted during the technical conference that the processing of the REC data was a major cost of the project.[29]

Here are some less important but nonetheless notable REC data problems.

- As is the case for Hydro One (but not for the American IOUs), the OM&A salaries and wages of RECs are not itemized. This reduces the accuracy of the OM&A input price indexes that can be calculated for RECs and used in benchmarking.

[26] One reason that we did not exclude these costs from our benchmarking study for 4th GIRM is that we did not believe that these had been properly itemized by all companies.

[27] HONI_Update_Ex_F_20170607, Exhibit F1/Tab 3/Schedule 1, p. 2.

[28] PSE addressed this problem by converting an employment cost index for *total* compensation that is obtained from the US Bureau of Labor Statistics (an index which *does* address benefits) to Canadian dollars using PPPs. An Ontario salary price index was, meanwhile, used in PSE's *productivity* research. See Fenrick TFP Study, *op. cit*., p. 21.

[29] Transcript, Technical Conference, March 1, 2018, *op. cit*., p. 50, lines 6-19.

- RECs are not investor-owned and may therefore have less incentive to contain cost than IOUs.
- RECs do not itemize net distribution plant value, so this must be estimated when computing the first year of the capital quantity index using crude formulas.

In view of all these deficiencies, it is questionable whether inclusion of REC data in the sample and PSE's exclusion from the sample of data for Ontario distributors like Algoma Power which serve rural areas was worthwhile.

- PSE used a 2002 benchmark year to calculate the capital cost of *all* utilities in the econometric cost sample, even though the requisite capital data are available since 1989 for most Ontario utilities, since 1995 for US RECs, and since 1964 for major US IOUs. Since capital cost typically accounts for more than 60% of the total cost of distributor base rate inputs in PSE's study, this substantially reduces the accuracy of the benchmarking work. Mr. Fenrick stated at the technical conference that a common 2002 benchmark year was necessary to avoid "bias," but did not explain the expected character of such bias.[30] It is not clear why making research more accurate makes it more biased. In our benchmarking and productivity research for the OEB, PEG has always measured capital quantities starting in the earliest year for which data are available, even though these years vary amongst Ontario distributors. PSE used a mix of benchmark years in its industry productivity update to maintain consistency with PEG's 4th GIRM study.[31]
- As in the productivity research, PSE uses a Handy Whitman construction cost index converted to Canadian dollars.[32]

Here are some smaller concerns we have with PSE's benchmarking study. We do not believe that these problems had a major impact on benchmarking results on balance. However, future benchmarking studies, by Hydro One and other utilities, which steer clear of these problems will have more credibility.

[30] Technical Conference Transcript Vol. 1, *op. cit.*, p. 50, line 24-p.54, line 5.

[31] Fenrick TFP Study, *op. cit*., p. 23.

[32] *Ibid.*, p.13.

- In the benchmark year, for all US utilities PSE calculated net *distribution* plant value as net *total* plant value multiplied by the share of total *gross* plant value which is distribution.[33] This is needlessly inaccurate since the requisite net distribution plant value data are available for the American IOUs in the sample.
- PSE uses peak demand data as a variable in the cost model. Available US data overstate distribution peak demand, since they can include the demand of a utility's wholesale customers. PSE did not adjust these data to make them more accurate. This made the performances of US distributors look better than they actually were.
- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for US utilities even though flexible weights are available for the American IOUs in the sample and a 70/30 split between labor and M&S isn't typical for these companies. Thus, the OM&A input price indexes for American distributors were needlessly inaccurate.
- The labor price levelization for Hydro One uses Ontario-wide data whereas levelization for all other utilities in the sample used labor prices specific to their service territories. The percentage of Hydro One distribution employees that work in large urban areas of Ontario where labor prices are highest is likely lower than the Ontario norm.
- The decision to take the logarithm of business condition variables was done inconsistently.
- No controls were made for large transfers of costs that some companies report between their transmission and distribution operations.[34] This compromises the accuracy of the capital cost estimates for these companies.
- Exclusion of Haldimand and Woodstock from the benchmarking study means that the study does not reflect all distribution operations of Hydro One. Haldimand has been a good performer in the Board's total cost benchmarking studies while Woodstock's performance has been similar to Hydro One's. The effect of these exclusions should not be large.
- PSE uses the US gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for HON. The Canadian GDPIPIFDD was

[33] *Ibid*., p.13.

[34] These transfers can go either way.

meanwhile used to deflate M&S expenses in PSE's research on the productivity of other Ontario power distributors.

PEG's recently completed benchmarking study for the UCA provides the Board with an alternative notion of how a transnational benchmarking study for Hydro One could be conducted. Advantages of our methodology over PSE's include the following.

- There are separate econometric benchmarking models for OM&A expenses, capital cost, capital expenditures, and total cost.
- The sample used in the research includes data for four Alberta distributors and several Ontario distributors (e.g., Hydro One and Algoma Power) as well as numerous investor-owned US electric utilities. Two Alberta distributors (FortisAlberta and ATCO Electric) are good peers for Hydro One because they serve areas with low customer density.
- Pension and other benefit expenses were excluded.
- Weights in the OM&A input price index were company-specific.
- US distributors with large reported transmission/distribution cost transfers were excluded.
- The benchmark year for the capital cost of US utilities was 1964.
- A system overheading variable was included.
- The density variable was not based on service territory area estimates.

4.2. Alternative Benchmarking Results

Mr. Fenrick noted in a response to a data request that Hydro One recently reported high voltage ("HV") plant additions to the OEB that were erroneously high.[35] We recomputed benchmarking results for Hydro One using the corrected capital cost data reported by the company and the total cost econometric model we developed for the OEB in 4th Generation IRM. Results are presented in Table 3. It can be seen that the three-year average cost performance of Hydro One was almost 33% over predicted cost. This level of cost performance is consistent with a 0.60% stretch factor instead of the

[35] Exhibit I/Tab 8/Schedule Staff-23 c).

Table 3

Impact of Revised High Voltage Data on Hydro One Benchmarking Results Using the OEB's Econometric Total Cost Model

	Before Correction	After Correction
2014	28.93%	39.94%
2015	19.68%	33.09%
2016	15.56%	25.73%
Average	21.39%	32.92%

0.45% as previously measured.[36] However, cost performance improved considerably over these years. By 2016, the Company's cost exceeded the model's prediction by 25.73%. We also developed a new econometric model that relies primarily on PSE's data but makes several changes to PSE's methodology to make it more in line with PEG's total cost model in the UCA study. Here are some changes to PSE's methodology that we made.

- REC data were excluded from the sample used in model estimation.
- Since the peak load variable parameter estimate was not statistically significant when the REC data were excluded, we used an alternative measure of peak demand: the volume of power deliveries per residential customer in 2015. Peak demand will tend to be higher where residential use per customer is high. Commercial use per customer is also pertinent but is more difficult to accurately measure. Industrial demand is less pertinent because large industrial customers in the States often receive power directly from the transmission system.
- An overheading variable was included. The variable we used was the share of overhead facilities in the gross value of overhead and underground distribution line plant.

[36] It is the understanding of PEG that it is the policy of the OEB to not revise previously assigned stretch factors due to data revisions. This information is being provided as additional evidence of the cost performance of HONI with the best data currently available. The adjusted results may include other OEB approved data corrections provided by the Company in 2017 relating to years prior to 2016.

- An alternative density variable was used that does not rely on an estimate of the service territory area. This variable was overhead structure miles per customer.[37] The statistical significance of the parameter of our density variable was considerably higher than that for the density variable PSE developed.
- US utilities with large transmission/distribution cost transfers were excluded.
- Scale economies are important when benchmarking the cost of a large distributor like Hydro One. To capture scale economies, our model included quadratic terms for the customer, density, and average use variables. To preserve degrees of freedom, we did not include interaction terms between the scale variables in the model.

The model otherwise used PSE's data, including the forestation, customer service and information, extreme weather, and artificial surface variables that PSE developed.

Details of this new econometric total cost model are reported in Table 4. It can be seen that all of the variables have statistically significant and plausibly-signed parameter estimates. The 0.958 adjusted R-squared for the model is quite high. Note that the trend variable parameter estimate suggests that the cost of sample distributors declined in real terms at a 0.20% annual pace for reasons other than the trends in the model's business condition variables.

Table 5 presents results when our preferred model is used to benchmark the cost of Hydro One. It can be seen that the Company's cost was 24.8% above the model's prediction on average over the three years from 2014 to 2016. Cost performance was a little better on average for forecasted/proposed costs in 2017 and 2018 and averages 23.0% over the 2019-2022 period. These results are similar to those from PSE's model.

[37] The source of data on overhead structure miles is the Utility Data Institute. We computed the ratio of line miles to customers for a single year for each sampled utility. This ratio should be fairly stable over time for most distributors.

Table 4

Details of PEG's Alternative Total Cost Benchmarking Model

VARIABLE KEY

N = Number of Electric Customers Served
F = Percent Forestation in Service Territory
CSI = Percent Cost Customer Service and Information Expenses
XW = Extreme Weather
Art = Percent of Territory that is Artificial Surfaces
OHMILES = Overhead Structure Miles per Customer
PCTOH = Percentage of Line Plant that is Overhead
RESUPC = MWh Deliveries per Residential Customer, 2015
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.964	288.651	0.000
N*N	0.019	5.040	0.000
OHMILES	0.184	18.527	0.000
OHMILES * OHMILES	0.094	5.856	0.000
RESUPC	0.034	1.955	0.051
RESUPC * RESUPC	-0.474	-3.730	0.000
F	0.151	30.053	0.000
CSI	0.006	2.047	0.041
XW	0.00003	16.798	0.000
Art	1.926	12.735	0.000
PCTOH	-0.107	-6.212	0.000
Trend	-0.002	-2.531	0.012
Constant	11.670	1264.902	0.000

Rbar-Squared	0.958
Sample Period	2002-2015
Number of Observations	942

Table 5

Benchmarking Results for Hydro One Using PEG's Total Cost Model

[Actual - Predicted Cost (%)][1]

Year	***Efficiency Score***
2002	6.9%
2003	5.6%
2004	2.1%
2005	5.4%
2006	12.1%
2007	15.9%
2008	15.8%
2009	20.2%
2010	25.1%
2011	23.8%
2012	23.4%
2013	25.8%
2014	28.2%
2015	23.2%
2016	23.1%
2017	*21.9%*
2018	*22.1%*
2019	*22.6%*
2020	*23.0%*
2021	*23.0%*
2022	*23.3%*
Average 2014-2016	**24.8%**
Average 2019-2022	**23.0%**

[1] Results presented are the log of the ratio of actual cost to the cost predicted by the econometric cost model.

Note: Italicized results are for forecasted costs.

Summing up, the total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark on average from 2014-2016 but was improving, reaching 25.73% in 2016. Our adaptations to PSE's model reveal a continuation of improved performance after 2016 and a forecasted cost that averages 22.8% above the benchmark during the plan term. We believe that the 22.4% average result for the 2016-18 period is most pertinent for establishing the stretch factor because the incentive that Hydro One had to understate OM&A growth in the 2019-22 period. On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor. Combined with the recommended 0% base X factor, this would give an X factor of 0.45%. The RCI formula would then be IPI - 0.45%, net of Z factors or of any growth factor as discussed elsewhere.

4.3. Program Benchmarking

Hydro One also filed several more granular or "program-based" unit cost benchmarking studies addressing components of its cost. Pole replacement, substation refurbishment, and vegetation management were notable focus areas.

PEG examined the First Quartile/Navigant report. Some advantages of the general approach to benchmarking that these consultancies use can be noted. Benchmarking specialists can confer with colleagues in other companies. Special data can be gathered if and when a need for better data is identified. Participants can learn about best practices.

Traditional peer group benchmarking also has special limitations. Companies outside Ontario will participate only on a voluntary basis and may insist on data confidentiality. Individual consultancies compete to create peer benchmarking groups, but each consultant typically has only 15-30 participants. The utilities that participate in these groups are often quite large (e.g., Southern California Edison) because this increases the cost-effectiveness of participation. It may therefore be difficult to establish appropriate peer groups for Ontario distributors. For example, only three good peers might be available and average results for these peers may not be representative of the norm for companies facing their business conditions. Statistical methods are often crude, due in part to the small size of data samples gathered. Econometric modelling and hypothesis testing are rare.

PEG examined the First Quartile/Navigant study and has several concerns.

- The authors claimed that their peer group was "reasonably representative and useful."[38] In fact, few utilities in the peer group are similar to Hydro One. The sample consisted mostly of US utilities serving large urban areas like Chicago, Dallas, Houston, Los Angeles, and Philadelphia. These utilities were probably easier for the consultants to recruit for the study because of their large size and participation in past First Quartile or Navigant studies. The authors of the report claimed in response to an information request that the peer group is representative of the "industry."[39] However, Hydro One's request for project proposals called, as it should, for peer groups facing business conditions like those of Hydro One.
- Statistical methods were basic and consisted chiefly of simple unit cost metrics adjusted for currency differences between the US and Canadian utilities. Exchange rates, not PPPs, were used to adjust for currency differences. PPPs are generally considered to be more accurate for making international price comparisons.
- Other differences in input prices faced by peer utilities were not considered. Yet many peers served large urban areas where input prices tend to be unusually high. Many Hydro One employees, in contrast, do not work in Ontario's two large metropolitan areas.
- The evidence is not transparent, since utility participation in the study was conditioned on confidentiality.[40] Some results were not made available for scrutiny.[41]
- The sample period for the First Quartile/Navigant study was 2012-2014, which is not very recent.

All in all, we believe it is constructive for Hydro One to participate in some studies of this kind. However, the value of the First Quartile/Navigant report in support of Hydro One's proposed stretch factor was quite limited.

[38] Navigant Consulting, *Distribution Unit Cost Benchmarking Study Pole Replacement and Substation Refurbishment*, HONI_App_Ex_B_Part2_20170427, B1-1-1, Section 1.6, Attachment 1, p. 5.

[39] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 10, Schedule Staff-51, p. 4.

[40] EB-2017-0049, Exhibit I, Tab 25, Schedule AMPCO-19, part j.

[41] EB-2017-0049, Exhibit I, Tab 10, Schedule SEC-25, part c.

5. Other Plan Design Issues

The IRM proposed by Hydro One is in several respects uncontroversial. The design is similar to that of the Custom IRM that the Board approved for Toronto Hydro-Electric System. A revenue cap index escalates OM&A revenue, strengthening performance incentives and sidestepping the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside the deadband. The CSVA would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor would ensure recovery of the proposed capital cost, but this cost is reduced by the proposed 0.45% X factor.

We are nonetheless concerned about some features of the Company's proposal. We discuss the major areas of our concern in this section and suggest alternative IRM provisions for the Board's consideration.

5.1. Revenue Cap Index

Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. In response to a data request, the Company defended this design on the grounds that the cost of system expansion is addressed by the C Factor.[42] For reasons discussed further below, we believe that it is preferable not to address capital costs by a C factor if it is efficient to address these costs by other means. Adding a growth escalator to the RCI is an efficient way to fund growth-related capex, including the acquisition of utilities. It reduces C-factored cost without increasing regulatory cost or weakening the Company's performance incentives.

On the other hand, Hydro One is not compensated under its proposal for higher OM&A expenses that result from higher output. This constitutes an implicit stretch factor in the Company's proposal. The addition of a scale escalator to the RCI would likely increase Hydro One's allowed revenue for OM&A expenses since there would likely be no offsetting increase in the X factor.

Were the Board to decide that a scale escalator should be added to the Company's RCI, our discussion of alternative scale escalators in the Appendix is pertinent. One option is an elasticity-weighted output index featuring cost driver variables. PEG developed such an index for the Board in the

[42] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 8, Schedule Staff-21, p. 2.

4th Generation IRM proceeding which featured delivery volume, peak demand, and the number of customers served as scale variables.[43] While fresh estimates of cost elasticities would be desirable, it is notable that the elasticity weights in this index are 0.106, 0.289, and 0.606, respectively.[44]

Table 6 considers how this index might serve as a scale escalator using Hydro One forecasts of billing determinants. These forecasts do not include the expected bump in customers when these acquired utilities are integrated into the Company during the plan term. The number of customers is forecasted to average 0.60% growth over the 4-year 2019-2022 period. The max peak is forecasted to be flat while the delivery volume is forecasted to average a 0.49% annual decline. The table shows that this output index would average a modest 0.31% annual growth during the plan term. Even if negative growth in subindexes weren't permitted, the index would grow by only 0.36%. In either case, OM&A revenue would grow by this additional amount. The C factor would fall but allowed capital revenue would likely be unaffected on balance.

Since this scale index tracks trends in volumes and peak load, its addition to the RCI would weaken Hydro One's incentive to encourage CDM. One solution to this problem is to escalate Hydro One's allowed revenue only for customer growth. There is ample precedent for this approach, including revenue cap indexes for Altagas and ATCO Gas in Alberta and a recent IRM of Enbridge Gas Distribution that indexed growth in allowed revenue per customer.[45] Hydro-Québec Distribution will soon begin operating under an RCI with a 0.75 x Customer growth escalator.[46] Many US gas and electric utilities operate under revenue decoupling systems that escalate allowed revenue each year for customer growth.

On balance, we believe that the RCI for Hydro One in this IRM should have a customer growth escalator. This escalator could have a % markdown like the 0.75 in the recently approved escalator for Hydro-Quebec. Setting aside the addition of the three utilities, escalation of allowed revenue for

[43] This index could, in principle, be expanded to encompass reliability, safety, and/or metering capabilities.

[44] The cost elasticity weights for the two scale variables in PSE's cost benchmarking model for Hydro One are 89% for customers and 11% for peak demand.

[45] Ontario Energy Board, Schedule A to Decision Dated February 11, 2008 Enbridge Gas Distribution Inc., filed in OEB Case EB-2007-0615, p. 8.

[46] La Régie de l'Energie, R-3897-2014, D-2017-043, April 2017.

Table 6

Forecast of Hydro One Scale Variables[1]

	Customers[2]		Volumes[2]		Max Peak[3]		4th GIRM Output Index[4]	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	PEG	Non-Negative GR Only
2012	1,311,445	0.66%	36,823	0.64%	6.09	0.00%	0.47%	0.47%
2013	1,323,658	0.93%	36,113	-1.95%	6.09	0.00%	0.36%	0.56%
2014	1,323,660	0.00%	36,266	0.42%	6.09	0.00%	0.04%	0.04%
2015	1,331,222	0.57%	35,514	-2.10%	6.09	0.00%	0.12%	0.35%
2016	1,340,493	0.69%	34,732	-2.23%	6.09	0.00%	0.18%	0.42%
2017	1,347,322	0.51%	33,988	-2.17%	6.09	0.00%	0.08%	0.31%
2018	1,355,818	0.63%	33,987	0.00%	6.09	0.00%	0.38%	0.38%
2019	1,363,783	0.59%	33,566	-1.25%	6.09	0.00%	0.22%	0.35%
2020	1,371,760	0.58%	33,491	-0.22%	6.09	0.00%	0.33%	0.35%
2021	1,380,395	0.63%	33,353	-0.41%	6.09	0.00%	0.34%	0.38%
2022	1,388,694	0.60%	33,330	-0.07%	6.09	0.00%	0.36%	0.36%
Annual Average Growth Rate								
2012 - 2017		**0.56%**		**-1.23%**		**0.00%**	**0.21%**	**0.36%**
2019 - 2022		**0.60%**		**-0.49%**		**0.00%**	**0.31%**	**0.36%**

Notes

[1] All growth rates are computed logarithmically. For example, growth rate of X = $\ln(X_t/X_{t-1})$.

[2] Source: *OEB Staff Interrogatory # 219*

[3] Max peak values are taken from PSE's working papers.

[4] The following cost elasticity weights were used in index construction: 0.6057 for customer numbers, 0.1058 for volumes, and 0.2885 for system capacity. The resultant elasticity weights are estimates from PEG's *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario* , 2013.

customer growth would likely average 0.6% annually if there was no markdown.[47] Once again, the OM&A revenue requirement would rise a little more rapidly but the C factor would fall and capital revenue would be unaffected.

[47] EB-2017-0049, Exhibit I/Tab 46/Schedule Staff-219, Filed: February 12, 2018.

If a customer growth escalator were added to the Company's RCI, we demonstrate in the Appendix that supportive productivity research to calibrate the X factor should use the number of customers as the scale variable.[48] As we showed in Section 3, this would increase the appropriate base productivity trend by about 30 basis points were X based solely on Ontario experience. However, Hydro One's Custom Productivity Measure would likely remain at 0%.

5.2. Capital Cost Treatment

The proposed ratemaking treatment of capital cost is similar to that which the Board approved for Toronto Hydro but nonetheless raises several concerns. The C factor ensures that the Company recovers its proposed capital cost less a perfunctory X factor markdown. Hence, capital revenue is chiefly determined on a cost of service basis. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. Notwithstanding the proposed claw back of some capex underspends, Hydro One still has some incentive to exaggerate capex needs since this strengthens the case for a C Factor and reduces pressure for capex containment.

Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, utilities can always claim that they "discovered" ways to economize under the force of stronger incentives. British distributors operating under several generations of IR based on cost forecasts have repeatedly spent less on capex than they forecasted.

Distributors are also incentivized to "bunch" their deferrable capex in ways that increase supplemental revenue. The data in Table 7 suggests that Hydro One may be pursuing this strategy now. The table shows that capital additions are forecasted to be higher than the norm for the 2013-2015 period after a three-year lull from 2016 to 2018. Hydro One proposes to build an Integrated System Operating Center right in the middle of the plan term when the impact on the C factor would be close to the greatest possible. The impact on the C factor would be much less if the center were finished in 2019 or 2022.

[48] Christensen Associates used the number of customers to measure output growth in its recent productivity research and testimony in support of a revenue cap index proposal by Eversource Energy, a large Massachusetts power distributor. Massachusetts Department of Public Utilities, DPU-17-05, Direct Testimony of Mark E. Meitzen, *Performance-Based Ratemaking Mechanism*, Exhibit ES-PBRM-1, January 2017.

Table 7

Actual, Forecasted, and Proposed In-Service Capital Additions 2013-2022 ($M)[49]

		Sustaining	Development	Operations	Customer Service	Common & Other	**Total**
Actual	**2013**	296.6	194.1	1.4	13.9	223.4	**729.4**
	2014	324.8	187.6	5	1.4	96.6	**615.4**
	2015	420.2	216.9	7	16.6	100.5	**761.2**
	2016	371.1	168.3	-0.3	6.5	109.3	**654.9**
Bridge	**2017**	310.7	179.1	12.7	12.7	136.7	**651.9**
Proposed	**2018**	292.5	194.4	2.2	30.2	121.5	**640.8**
	2019	335.6	268.9	10.3	0.2	160.6	**775.6**
	2020	361.5	218.9	68.9	0.2	118.6	**768.1**
	2021	384.2	219.2	1.6	0.2	129.1	**734.3**
	2022	427.3	221	20.2	0.2	146.5	**815.2**

Averages						
2013-2015	**347.2**	**199.5**	**4.5**	**10.6**	**140.2**	**702.0**
2016-2018	**324.8**	**180.6**	**4.9**	**16.5**	**122.5**	**649.2**
2019-2022	**377.2**	**232.0**	**25.3**	**0.2**	**138.7**	**773.3**

Another problem with the proposal is that customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high, even though most of the capex in question is likely to be similar in kind to that incurred by distributors in the productivity research sample used to calibrate X.[50] Utilities can then be compensated twice for the same capex: once via the C factor and then again by a low X factor in this and future IRMs. A similar concern about "double dipping" arises concerning distribution capex costs that are Z factored due to exogenous events such as severe storms and highway construction programs. These costs are also incurred by distributors in the productivity research sample and slow their productivity growth. Customers are asked to provide supplemental compensation for a disadvantageous short term need for high capex but are not offered timely revenue reductions for expected cost reduction opportunities such as the acquisition of other utilities.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Hydro One's incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal. This raises regulatory cost. The need for the

[49] OEB Proceeding EB-2017-0049, HONI_Update_Ex_D_20170607, Exhibit D1/Tab 1/Schedule 2, pp 1,3.

[50] Hydro One would not, however, be compensated for unexpected capex overruns.

OEB to sign off on multiyear total capex proposals complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. The regulatory cost of Hydro One's C factor proposal is further raised by the provision that it be permitted to keep legitimate capex productivity gains. The Company will be incentivized to pursue its claims under this provision energetically.

Despite the extra regulatory cost, OEB's staff and stakeholders are sometimes hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that Ofgem has made in the capability for appraising and ruling on capex proposals.[51]

In pondering this quandary, the following remarks of the OEB in its decision approving IR for Toronto Hydro resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[52]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

Following an unhappy experience with capital cost trackers in Alberta's first generation IRMs for provincial power distributors, a number of possible reforms to the ratemaking treatment of capital were discussed in the recent Alberta Utilities Commission ("AUC") generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital

[51] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research. Despite these investments, it is still unclear as to how accurate Ofgem's assessments are.

[52] OEB, *Decision and Order*, EB-2014-0116, Toronto Hydro-Electric System Limited, December 29, 2015, p. 2.

revenue which was less dependent on distributor capex forecasts.[53] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a consumer group in that proceeding, we believe that the following amendments to Hydro One's proposed ratemaking treatment of capital merit consideration.

- The C factor could, like the ICMs in 4th Generation IRM, be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised, in this and Hydro One's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The C factor could be calculated using the (slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the (faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. However, there is no conclusive research available to the OEB in this proceeding on OM&A and capital productivity trends of power distributors.

If the OEB is prepared to deviate from Hydro One's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans is most in keeping with its current policies. This could be done in such a manner that the first 10% of unfunded capex (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the incremental capital modules used in 4th GIRM. For example, if proposed capex exceeded the materiality threshold, a set percentage

[53] PEG is not recommending this ratemaking treatment for Hydro One.

of *all* unfunded capex could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capex at the margin. A similar idea is for a set number of basis points (e.g., 50) of the otherwise appropriate C factor to be disallowed. The OEB disallowed a 10% share of Toronto Hydro's proposed capex in a recent proceeding.[54] Any of these dead zone approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI.

5.3. Revenue Decoupling

Consider next that Hydro One's proposal includes a revenue cap index but not revenue decoupling. Decoupling is popular in US jurisdictions (and Great Britain) and is often paired with revenue caps. In the absence of decoupling there may be controversy in proceedings to review the billing determinant forecasts that Hydro One will be required to file each year to convert allowed revenue to rates. Decoupling would add a small step to the Company's IRM but would eliminate billing determinant controversy. The need for an LRAM would also be eliminated since revenue as adjusted would be insensitive to the impact of CDM. Decoupling would also encourage the Company to use its AMI to implement time-sensitive rates because it would reduce the risk of demand fluctuations and load shifting that these rates entail. Hydro One's proposed LRAM does not extend to demand management.

On the other hand, the importance of system use forecasts is diminishing in Ontario due to the transition of rate designs for residential customers to fully-fixed pricing. Ontario's government requires that lost revenues do not weaken distributor incentives to embrace DSM but does not require LRAMs to accomplish this.[55] However, the OEB has mandated LRAMs for the 2015-2020 period.[56] These considerations reduce the benefits of adopting decoupling.

5.4. Pension and Benefit DVAs

With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. There is a perverse incentive for the Company to contain salary growth but maintain or sweeten benefits. This increases the need for prudence oversight of these expenses by the

[54] OEB, *Decision and Order*, EB-2014-0116, *op. cit*., p. 29.

[55] Ontario Executive Council, *Order in Council*, approved and ordered March 26, 2014.

[56] Ontario Energy Board, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278, December 19, 2014 (Updated August 11, 2016).

OEB and stakeholders, raising regulatory cost. Many IRMs in North America do not have DVAs for pension and other benefit expenses. For example, Enbridge Gas Distribution and Union Gas have not proposed a DVA for these costs in their current IRM proposal.

Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism. For example, the first 10% of annual variances can be declared ineligible for rate adjustments. Alternatively, a set percentage of the entire variance can be ineligible if the threshold is exceeded. PEG recently proposed a similar treatment of pension and other benefit expenses in an IRM for Hydro-Québec Distribution.[57]

[57] La Régie de l'Energie, R-4011-2017, Présentation de PEG, C-AQCIE-CIFQ-0057, February 9, 2018, p. 14.

Appendix

Productivity Research and its Use in Regulation

This Appendix considers some technical and theoretical issues that arise in productivity research to support X factor choices in IRMs. We emphasize issues that arise in our appraisal of Hydro One's productivity research and IRM proposal in this proceeding.

Productivity Indexes

<u>The Basic Idea</u>

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The trend in a productivity index is the difference between the trend in an output index ("Outputs") and the trend in an input quantity index ("Inputs").

trend Productivity = trend Outputs – trend Inputs. [A1]

Productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. *Partial* factor productivity ("*PFP*") indexes measure productivity in the use of particular kinds of inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple kinds of inputs. In Ontario, these are usually called *total* factor productivity ("*TFP*") indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, growth in each output dimension which is itemized is measured by a subindex. Growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[58] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \qquad [A2a]$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[59] These have been used on several occasions in our previous research for the OEB.[60] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [A2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[61] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

[58] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[59] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[60] See, for example, Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K., *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, in EB-2010-0379, (2013); Lowry, M., Getachew, L., and Fenrick, S., *Benchmarking the Costs of Ontario Power Distributors* in EB-2006-0268, (2008) and Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007).

[61] See, for example, Denny, Fuss and Waverman, *op. cit.*

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.[62]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency level.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses will cause OM&A and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium run. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since

$$\begin{aligned} \textit{trend } TFP^R &= \textit{trend Outputs}^R - \textit{trend Inputs} + (\textit{trend Outputs}^C - \textit{trend Outputs}^C) \\ &= (\textit{trend Outputs}^C - \textit{trend Inputs}) + (\textit{trend Outputs}^R - \textit{trend Outputs}^C) \\ &= \textit{trend } MFP^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C). \end{aligned} \qquad [A3]$$

Relation [A3] shows that the trend in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

[62] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow in size.

The output differential is sensitive to changes in external business conditions such as those that drive system use.[63] For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Price Cap Indexes

Index logic supports the use of index research in price cap index design. We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[64] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [A4]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*^{R}") and billing determinants ("*Outputs*^{R}")

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}^R. \qquad [A5]$$

The trend in cost can be shown to be the sum of the trends in a cost-weighted input price index ("Input Prices") and input quantity index ("Inputs").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [A6]$$

It follows that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and a total factor productivity index of TFP^R form.

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [A7]$$

$$= \textit{trend Input Prices} - \textit{trend } TFP^R.$$

The result in [A7] provides a conceptual framework for the design of PCIs of general form

[63] Note also that companies can sometimes bolster their output differential with better marketing. For example, they can sell more products that have a higher margin between incremental revenue and cost.

[64] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

$$\textit{growth Rates} = \textit{growth Input Prices} - X. \qquad \text{[A8a]}$$

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^R}$") that is typically the trend in the TFP^R of the regional or national utility industry or some other peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the IRM.[65]

$$X = \overline{TFP^R} + \textit{Stretch} \qquad \text{[A8b]}$$

Since the X factor often includes *Stretch* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

Revenue Cap Indexes

Index logic also supports the design of *revenue* cap indexes. Consider first the following basic result of cost theory:

$$\textit{trend Cost} = \textit{trend Input Prices} - \textit{trend Productivity}^C + \textit{trend Scale}^C. \qquad \text{[A9a]}$$

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Scale}^C \qquad \text{[A9b]}$$

where

$$X = \overline{TFP^C} + \textit{Stretch}. \qquad \text{[A9c]}$$

Notice that a *cost*-based scale index should be used in the supportive productivity research.

PEG used an elasticity-weighted output index in its research for the OEB on the productivity growth of Ontario power distributors in the 4th GIRM proceeding. The output variables were delivery volume, peak demand, and the number of customers served. These variables are billing determinants as well as cost drivers. Equations [A9a-c] permit the expansion of an elasticity-weighted output index used

[65] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

in RCI design to include outputs that are not billing determinants. For a power distributor these might include kilometers of line, reliability, safety, and metering capabilities of the system.

A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote CDM. This is a strong argument for excluding these variables from an RCI scale escalator. Note also that values of usage variables can decline, materially slowing RCI growth even though cost is largely fixed in the short run with respect to system use.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue cap index. The number of customers is an important distributor cost driver in its own right and is also highly correlated with peak load. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost.

We can expand [A6] to obtain the result

$$
\begin{aligned}
\textit{trend Cost} &= \textit{trend Input Prices} + \textit{trend Input Quantities} + (\textit{trend Customers} - \textit{trend Customers}) \\
&= \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\
&= \textit{trend Input Prices} - \textit{trend } TFP^{N} + \textit{trend Customers}
\end{aligned}
$$

where TFP^{N} is a TFP index that uses the number of customers to measure output. This result provides the rationale for the revenue cap index formula

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Customers} \qquad \text{[A10a]}$$

where

$$X = \overline{TFP}^{N} + \textit{Stretch}. \qquad \text{[A10b]}$$

An equivalent formula is

$$
\begin{aligned}
&\textit{growth Revenue} - \textit{growth Customers} \\
&\quad = \textit{growth } (\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \qquad \text{[A10c]}
\end{aligned}
$$

This is sometimes called a "revenue per customer" index, and we will for convenience use this expression to refer to revenue cap indexes which conform to either [A10a] or [A10c].

Revenue per customer indexes are currently used in the IRMs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Hydro-Québec Distribution and Gaz Métro to develop IRMs featuring revenue per customer indexes. Revenue per customer indexes were previously featured in IRMs for Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the US and Canada, respectively. In the United States, many gas and electric utilities operate under revenue decoupling systems which escalate allowed revenue for customer growth between rate cases.

TFP Research Methods

Monetary Approach to Capital Cost and Quantity Measurement

Monetary approaches to the measurement of capital costs and quantities have been widely used in TFP research. The main components of capital cost are depreciation expenses, the return on investment, and taxes.[66] These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$\textit{growth Cost}^{Capital} = \textit{growth Price}^{Capital} + \textit{growth Quantity}^{Capital}. \qquad [A11]$$

The capital quantity trend is calculated using deflated data on asset values.

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic dollars or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from plant additions. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

Three monetary methods have been used in research to calibrate the X factors of IRMs.

- The geometric decay ("GD") method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

[66] The trends in these costs depends on trends in construction prices, tax rates, and the market rate of return on capital. A capital price index should reflect these trends. The capital price index is sometimes called the "rental" or "service" price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

Academic research has supported use of the GD method to characterize depreciation in many industries. [67] GD has also been widely used in productivity studies, including X factor calibration studies. The US Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[68] PEG has used the GD method in most of its productivity research for the Board, including the research for 4th Generation IRM.

- The one hoss shay method assumes that the quantity of capital from plant additions in a given year does not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. We have found that productivity results using the one hoss shay method are unusually sensitive to the choice of an average service life. The one hoss shay method has nonetheless been used occasionally in research intended to calibrate utility X factors.
- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[69]

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely

[67] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right", University of Maryland working paper, 2008.

[68] The BEA states on p. 2 its November 2015 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

[69] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

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BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of a consulting firm in the field of utility economics. Leads internationally recognized practice performance-based regulation and utility performance research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

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Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
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217. Research and Testimony on Performance-Based Regulation for a Midwest Utility, Northern States Power (MN), ongoing.
218. Research and Testimony on Gas Utility Productivity for a Canadian Regulator, Ontario Energy Board, ongoing.
219. Research on Granular Power Distributor Cost Benchmarking for a Canadian Regulator, Ontario Energy Board, ongoing.

Publications

1. Public vs. Private Management of Mineral Inventories: A Statement of the Issues. Earth and Mineral Sciences 53, (3) Spring 1984.
2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).

6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, Resources and Energy 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. Energy Economics 10 (4) 1988.
12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
15. Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric. In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute, 1991).
16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.
23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.

29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Assessing Rate Trends of U.S. Electric Utilities", Edison Electric Institute, January 2006.
36. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
37. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
38. "Alternative Regulation for Infrastructure Cost Recovery", Edison Electric Institute, January 2007.
39. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
40. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
41. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
42. "Alternative Regulation, Benchmarking, and Efficient Diversification", USAEE Dialogue, August 2009.
43. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
44. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" (With Lullit Getachew), Review of Network Economics, December 2009
45. "Forward Test Years for US Electric Utilities" (With David Hovde, Lullit Getachew, and Matt Makos),
Edison Electric Institute, August 2010.
46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf), Lawrence Berkeley National Laboratory, January 2016.
50. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," (With Jeff Deason), Lawrence Berkeley National Laboratory, July 2017.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans LA, March 1986
2. International Association of Energy Economists, Calgary AL, July 1987
3. American Agricultural Economics Association, Knoxville TN, August 1988

4. Association d'Econometrie Appliqué, Washington DC, October 1988
5. Electric Council of New England, Boston MA, November 1989
6. Electric Power Research Institute, Milwaukee WI, May 1990
7. New York State Energy Office, Saratoga Springs NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell MT, May 1994
12. Edison Electric Institute, Washington DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando FL, March 1995
14. Illinois Commerce Commission, St. Charles IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco CA, April 1996
18. AIC Conferences, Orlando FL, April 1996
19. IBC Conferences, San Antonio TX, June 1996
20. American Gas Association, Arlington VA, July 1996
21. IBC Conferences, Washington DC, October 1996
22. Center for Regulatory Studies, Springfield IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving TX, Sept. 1997
27. American Gas Association, Washington DC [national telecast], September 1997
28. Infocast, Miami Beach FL, Oct. 1997
29. Edison Electric Institute, Arlington VA, March 1998
30. Electric Utility Consultants, Denver CO, April 1998
31. University of Indiana, Indianapolis IN, August 1998
32. Edison Electric Institute, Newport RI, September 1998
33. University of Southern California, Los Angeles CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio TX, April 2000
38. Infocast, Chicago IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster MA, July 2000
41. Infocast, Washington DC, October 2000
42. Wisconsin Public Utility Institute, Madison WI, November 2000
43. Infocast, Boston MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa FL, August 2001
45. Infocast, Washington DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto ON, March 2002
47. Canadian Electricity Association, Whistler BC, May 2002
48. Canadian Electricity Association, Montreal PQ, September 2002
49. Ontario Energy Association, Toronto ON, November 2002
50. Canadian Gas Association, Toronto ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003

53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007
69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]
74. Edison Electric Institute, national eforum, May 2009
75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas NV, March 2013
85. Edison Electric Institute Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
95. Lawrence Berkeley National Laboratory, Vermont Future of Electric Utility Regulation Workshop
    January 2016
96. Great Plains Institute, Minneapolis MN, February 2016
97. Wisconsin Public Service Commission, Madison WI, March 2016
98. Society of Utility Regulatory Financial Analysts (SURFA), Indianapolis IN, April 2016
99. Edison Electric Institute, Madison WI, July 2016
100. Lawrence Berkeley National Laboratory, Webinar, November 2016

101. Washington State House of Representatives, Technology and Economic Development Committee, January 2017
102. National Regulatory Research Institute, Webinar, May 2017
103. National Conference of Regulatory Attorneys, Portland OR, May 2017
104. Edison Electric Institute, Madison WI, July 2017
105. Lawrence Berkeley National Laboratory, Webinar, August 2017
106. New England Conference of Public Utilities Commissioners, Hallowell ME, September 2017
107. Wisconsin Public Utilities Institute, Madison WI, October 2017
108. University of Wisconsin Department of Applied Economics, October 2017
109. NARUC, St Paul MN, January 2018

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist
Wisconsin Public Utilities Institute

FORM A

Proceeding: EB-2017-0049

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Mark Newton Lowry (*name*). I live at Madison (*city*), in the State (*province/state*) of Wisconsin.

2. I have been engaged by or on behalf of Ontario Energy Board (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date April 5, 2018

Signature