# Empirical Research for Incentive Regulation of Transmission

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# 1. Introduction and Summary

## 1.1. Introduction

Hydro One Sault Ste. Marie LP ("Hydro One SSM"), a small power transmission utility serving a region east of Lake Superior, recently filed an application with the Ontario Energy Board ("OEB") for an incentive rate-setting mechanism ("IRM") that it calls Revenue Cap Incentive Rate-setting.[1] Over the eight-year 2019-2026 period, the revenue requirement would be escalated by a revenue cap index featuring a custom inflation measure and an X factor of zero. The revenue requirement would thus increase at the rate of inflation. The proposed X factor is supported by a report on transmission productivity and cost benchmarking research by Power System Engineering ("PSE"), a Madison, Wisconsin consulting firm. Steven Fenrick and Erik Sonju were the authors of the PSE report.[2]

Hydro One SSM was created after the acquisition of Great Lakes Power Transmission Inc. in 2016 by Hydro One, Inc. It is now being integrated into the larger transmission operations of Hydro One Networks Inc. ("Hydro One Networks" or "the Company") but its rates are still separately regulated. The PSE report does not consider the performance of Hydro One SSM but addresses both the historical and future total cost performance and multifactor productivity ("MFP") trend of Hydro One Networks' transmission operations. PSE also calculated the transmission MFP trends of a sample of U.S. electric utilities.

The PSE research and testimony merit careful examination in this proceeding for several reasons:

- Ontario's power transmission industry is sizable, and transmission accounts for a material portion of the rate-regulated charges of electric utilities, especially in the industrial sector. The OEB has long expressed an interest in extending incentive regulation ("IR") to this sector.

[1] EB-2018-0218

[2] Mr. Fenrick, a former employee of PEG, recently left PSE and is now a Principal Consultant and Partner of Clearspring Energy Advisors in Madison. Mr. Sonju is the President of PSE.

- No "top down" statistical benchmarking study of Hydro One Networks' transmission cost has ever been filed with the OEB. Neither has a study been filed on the transmission productivity trends of Hydro One Networks or U.S. utilities.
- Hydro One Networks is expected to file a Custom IR proposal for its principal transmission operations in the near future. This proposal is likely to be supported by the same or similar (e.g., updated) transmission productivity and benchmarking research. In addition, the revenue cap index chosen in the proceeding may be used to escalate the Company's 2019 revenue requirement.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity consultant. We have in past years done power transmission benchmarking and productivity studies and have recently played a large role in the development of an IRM for transmission services of Hydro-Québec. OEB staff has retained us to review PSE's transmission productivity and cost benchmarking evidence and to prepare alternative studies.

This is our report on this work. Following a brief summary of our findings, Section 2 provides our critique of PSE's empirical research and testimony. Section 3 discusses productivity and benchmarking research by PEG using alternative methods. We provide in Section 4 our stretch factor and X factor recommendations for Hydro One SSM's proposed rate plan. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses various topics in the report in more detail.

## 1.2. Summary

PSE developed an econometric model of transmission cost using a sample of operating data for Hydro One Networks and 56 U.S. electric utilities over the 2004-2016 sample period. This model was used to benchmark the transmission cost of Hydro One Networks over the same historical period as well as the Company's forecasted/proposed cost for the 2017-2022 period. Econometric estimates of scale variable parameters in the model were used to construct a multidimensional scale (or output) index for the productivity research.

### Productivity Trends

Using data from Hydro One Networks and 47 U.S. transmitters, PSE also calculated a -**1.71%** average annual MFP growth trend over the full 2005-2016 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged -0.84% annual growth while capital productivity averaged -1.93% annual growth. PSE nevertheless recommends a **0.00%** base productivity trend for the revenue cap index and Hydro One SSM embraced this proposal. The 1.71% difference is portrayed as an implicit stretch factor.

PSE reports that the transmission productivity growth trend of Hydro One Networks was considerably better during the same period. Annual MFP growth of Hydro One Networks averaged **-0.31%** while OM&A productivity averaged 1.07% annual growth and capital productivity averaged -0.58% growth. Over the 2020-2022 period, PSE reports that the forecasted/proposed total cost of Hydro One Networks would reflect a -1.31% average annual MFP growth. OM&A productivity would average 0.12% annual growth while capital productivity would average -1.67% growth.

Our examination of PSE's research raised concerns about its calculations of U.S. transmission productivity. Here are the most important ones.

- The 2005-16 sample period was one during which U.S. power transmission productivity was strongly influenced by policy initiatives of the U.S. government such as the Energy Policy Act of 2005. Reliability standards were established and enforced that raised costs for many utilities. Incentives to contain cost were weakened by special investment incentives and by the formula rate plans under which a growing number of transmitters operated. We believe that a longer sample period is desirable in a study intended to inform the selection of a base productivity growth trend for Hydro One SSM or Hydro One Networks.
- PSE's productivity index features a multidimensional scale index with cost elasticity weights. This general approach is appropriate for calibrating the X factor of a revenue cap index. However, poor screening by PSE of data resulted in an econometric cost model with unreliable cost elasticity estimates for the scale variables that PSE used to construct its MFP index. As a consequence, less weight was placed on the more rapidly growing variable (peak demand) and more weight on the variable with slower growth (line length).
- PSE's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities have joined independent transmission system operators or regional transmission organizations and this materially affected the reported OM&A expenses of some companies. Exclusion from the calculations of costs that

were especially sensitive to this restructuring produces considerably more rapid productivity growth estimates.

- The calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate. For example, the benchmark year was 1989 whereas a benchmark year of 1964 is possible. Capital cost was not calculated net of capital gains.

These and other concerns prompted us to develop our own U.S. transmission productivity study using preferred methods and data for a similar group of companies over the longer 1996-2016 sample period. We found that growth in the transmission MFP of sampled utilities averaged **-1.82%** over the 2005-2016 sample period chosen by PSE and **-0.34**% over the full sample period. OM&A productivity growth averaged -1.40% over the shorter sample period but -0.53% over the full period. Transmission capital productivity growth averaged -1.73% over the shorter period but -0.21% over the full period. Our estimates of these trends do not reflect any possible improvements in U.S. transmission reliability due to changing federal policies.

Over the 2005-2016 historical sample period over which data are available, we calculated that the annual transmission MFP growth of Hydro One Networks averaged **-1.21** % while its OM&A productivity growth averaged 0.85% and its capital productivity growth averaged -1.86%. Over the first four years of the proposed plan (2019-2022), the Company's cost forecast is consistent with -2.21% average annual MFP growth, -0.60% OM&A productivity growth, and -2.57% capital productivity growth. Forecasted/proposed costs thus reflect productivity growth that is well below long-run U.S. norms.

## Hydro One Cost Benchmarking

PSE reports that the total transmission cost of Hydro One Networks was a substantial 27.3% below its cost model's prediction over the three most recent years for which data are available (2014-2016). The Company's forecasted/proposed total cost is 31.8% below the model's predictions during the first four years of the proposed IRM (2019-2022).

We had several major concerns about PSE's cost benchmarking work.

- Calculation of the Company's capital cost was quite crude due to a lack of appropriate capital cost data.

- Calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate

- The short sample period unnecessarily reduced the accuracy of cost model parameter estimates.
- Estimates of the important scale variable parameters are particularly inaccurate due to inadequate screening of the data.
- Data for some U.S. utilities may be non-comparable due to their participation in RTOs .
- U.S. input price indexes were used for Hydro One where Canadian indexes would be better.

These and other concerns prompted us to benchmark Hydro One Networks' total cost with our own econometric model. The longer sample period makes estimates of the parameters of our model more accurate. This model also features our preferred capital cost specification and produces substantially different results for Hydro One Networks. The Company's transmission cost was found to be 9.43% below the model's prediction on average during the three most recent historical years for which data are available. The Company's forecasted/proposed total cost is only 1.23% below our model's prediction on average during the 2019-2022 period.

## Stretch Factor

We disagree with PSE's 0% explicit stretch factor recommendation, which is based on the premise that a stretch factor is not warranted because the company is a superior cost performer. One reason we disagree is that we do not have benchmarking results for Hydro One SSM. Another and more important reason is that we do not get such favorable benchmarking results for Hydro One Networks. A third is that our U.S. transmission productivity research does not suggest that a 0% base productivity trend involves a large implicit stretch factor.

In addition, we have long believed that, in addition to utility operating efficiency, stretch factors should reflect the difference between the incentive power of the contemplated IRM and the incentive power of the regulatory system under which utilities in the study used to set the base productivity trend operated. Hydro One SSM proposes to operate under a lengthy multiyear rate plan with limited earnings sharing whereas the formula rate plans and special incentives that many transmitters in the productivity sample operated under materially weakened their cost containment incentives. Based on the formula rates alone, the incentive power research detailed in Appendix B of the report suggests that, if the base productivity trend were based solely on U.S. data for the 2005-2016 period, the indicated stretch factor for HOSSM assuming average cost performance should lie in the [0.50-1.01] range.

## X Factor

Our X factor recommendation is to combine a **-0.34%** base productivity trend drawn from our U.S. MFP research for the full sample period with a **0.30%** stretch factor. With rounding this produces an X factor of **0.00%**.

# 2. Critique of PSE's Research and Testimony

## 2.1. Industry Productivity Research

PSE calculated the transmission MFP trends of Hydro One and 47 U.S. electric utilities over the twelve-year 2005-2016 period. A -**1.71**% average annual MFP growth trend was reported over this period. OM&A productivity growth averaged -0.84% while capital productivity growth averaged -1.93%.

Growth in operating scale was calculated using a multidimensional index with two scale variables: line length and ratcheted maximum peak demand. The weights for these variables were obtained from PSE's econometric cost research. The weight for line length was 74% whereas the weight for peak demand was 26%.

Capital cost was measured using a variant of the geometric decay monetary method in which capital gains were not considered. The benchmark year in the capital cost computation was 2002 for Hydro One Networks and 1989 for the sampled U.S. industries.

## 2.2. PEG Critique

Our review of PSE's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we begin this section by highlighting our most important concerns with PSE's methodology. There follows a brief discussion of some of our other concerns.

### Major Concerns

<u>Sample Period</u>

We first discuss our concerns with the sample period for the study. A twelve-year sample period is fairly brief for an X factor calibration study, and it is generally desirable to report results for a longer period than the practitioner favors. Our major concern with the 2005-2016 sample period, however, is that transmission MFP growth was strongly influenced during these years by policy initiatives of the U.S. government such as the Energy Policy Act of 2005. These initiatives included ROE premia for some kinds of transmission capex and the creation of new reliability standards that caused transmitters to incur Critical Infrastructure Protection ("CIP") costs. In addition to the fact that the slowdown in productivity growth due to CIP standards is temporary, Hydro One SSM may seek to Z factor any incremental CIP costs that may occur during its IRM, or request incremental capital revenue, if these costs are sizable.

PSE makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One SSM or Hydro One Networks during the period of their upcoming IRMs. In response to OEB staff interrogatory 68, PSE indicates that it is uncertain about the sources of negative productivity growth during this period.

A related concern is that a sizable and growing number of the transmitters operated under formula rate plans approved by the Federal Energy Regulatory Commission ("FERC") during the sample period. These plans feature comprehensive cost trackers that weakened cost containment incentives. PSE acknowledged in response to OEB staff interrogatory 68 that formula rate plans are widely used by U.S. transmitters and weaken their incentives.

While some of the resultant cost increases during this period were necessary, and may lead in the future to productivity gains, incentives for transmitters to contain cost were unusually weak. U.S. government regulation of power transmission is discussed further in the Appendix.

The 2005 start date of the sample period that PSE chose was ostensibly chosen due to the fact that this is the first year that data are available for a peak demand variable that PSE used in its econometric model and scale index. However, we do not believe this variable is essential to the study since an alternative and satisfactory peak demand variable is available for which data are available for additional years.

PSE relied on the Monthly Transmission System Peak Load data reported on page 400 of the FERC Form 1. These data have two limitations. Firstly as noted, the data only began to be reported in 2004, limiting the sample period. Secondly, some companies misreported their peak demand. For example, the Southern Company operating utilities reported the peak demand for the entire transmission system peak of these companies rather than at the individual operating company level.

It is reasonable to instead rely on the Monthly Peaks and Output data, reported on page 401b of the FERC Form 1, to construct a ratcheted peak demand variable. These data do not include non-requirements sales for resale. Non-requirements differ from requirements in that requirements sales for resale are contractually firm enough that the party receiving the power is able to count on this power for system capacity resource planning. Non-requirements sales for resale do not meet this standard and will include economy energy. Unlike requirements sales for resale, the load associated with non-requirements sales for resale can be shed in times of capacity constraints.

Scale Index

We have two major concerns with PSE's scale index. One is that inadequate screening by PSE of the peak load data it used led to spurious econometric estimates of the cost elasticities of the two scale variables that PSE used. PSE acknowledged that this was a consequential problem in response to OEB staff interrogatory number 65.

The cost elasticity of the peak load variable should be as large or larger than that of the line length. As it happens, peak load grew considerably more rapidly than transmission line length during the sample period. These limitations of the scale index therefore tend to bias productivity results downward.

Structural Change

PSE's treatment of OM&A expenses does not handle structural change in the transmission industry well. As discussed further in Appendix B, many U.S. electric utilities joined independent system operators or regional transmission organizations in the last twenty years. These agencies performed some of the functions that the utilities had previously undertaken. Many utilities in the sample began taking transmission service from these agencies, and this could materially affect the reported costs of some companies.

Capital Cost Specification

We have two major concerns about PSE's capital cost specification. One is that a 1989 benchmark year was employed for all sampled U.S. utilities even though the requisite data are available back to 1964. The benchmark year for Hydro One Networks is 2002.[3] We explain in Appendix section A.2 that a recent benchmark year can materially reduce the accuracy of capital cost and quantity estimates. Our other major concern is that PSE does not reduce capital cost by capital gains. Since assets are denominated in current rather than historical dollars, this improperly increases the weight on the capital quantity trend.

[3]Hydro One Networks apparently does not have plant value data that would permit an earlier benchmark year. We understand that this is due in part to historical circumstances beyond the Company's control.

### Other Concerns

A number of smaller problems with PSE's power transmission productivity research also merit mention.

An error was made in PSE's benchmark year calculation.

## 2.3. Hydro One Networks' Cost and Productivity Performance

### PSE Research

PSE also calculated the transmission MFP trend of Hydro One Networks over the 2005-2016 period and the MFP trend implicit in forecasted/proposed costs from 2017 to 2022. Over the full historical sample period, the Company's -0.031% average annual MFP growth was more positive than that which PSE reported for the full sample. OM&A productivity averaged 1.07% growth whereas capital productivity averaged -0.58% annual growth. Over the 2020-2022 period the Company's forecasted/proposed costs would produce -1.43% annual MFP growth. OM&A productivity would average 0.12% annual growth while capital productivity would average -1.67% annual growth.

PSE reports that the total transmission cost of Hydro One SSM was a substantial 27.3% below its econometric cost model's prediction on average over the three most recent years for which data are available (2014-2016). The Company's forecasted/proposed total cost is 31.8% below the model's predictions during the first four years of the proposed IRM (2019-2022).

### PEG Critique

Our review of PSE's benchmarking work and calculations of Hydro One Networks productivity trends revealed several concerns. Here are the most important ones:

- The relatively short sample period unnecessarily reduces the precision of the econometric benchmarking model parameter estimates.
- Parameter estimates are also degraded by the 1989 benchmarking year for U.S. utilities, which unnecessarily reduces the precision of the capital cost calculations,
- Due to data limitations beyond the control of PSE, the even more recent benchmark year for the Company reduces the accuracy of total cost benchmarking and multifactor productivity results for the Company.
- The capital cost specification excludes capital gains.

- We do not object in principle to the use of a weather-related loading variable but note that it is an example of developing a variable to address a special cost disadvantage of the Company when cost advantages could be ignored. Moreover, the accuracy of the calculation of the value for Hydro One is critically important.
- The accuracy of benchmarking Hydro One Networks is also reduced by our lack of knowledge about Ontario and US practices regarding power transmission customer contributions. This problem is not specific to the PSE study.

Here are some less important but nonetheless notable concerns:

- The scale index is inappropriate for the reasons stated above. However, this does not matter greatly for Hydro One Networks because the trends in the values of the scale variables are similar for the Company.
- Only Toronto values were used to levelize the construction cost index for the Company even though most of the transmission system is located at a considerable distance from Toronto.
- The calculations do not use Ontario inflation indexes. For example, the Handy Whitman Index for power transmission construction costs in the North Atlantic region of the United States was used to deflate the plant values of Hydro One Networks. We believe that the Statistics Canada's implicit price index for the capital stock of the Ontario utility sector is a more appropriate asset price deflator for the Applicants.

# 3. Alternative Empirical Research by PEG

## 3.1 Data Sources

The source of data on the transmission cost, transmission system capacity, and peak demand that we used in our benchmarking and productivity research is FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[4] More recently, these data have been available electronically in raw form from the FERC, and in more processed forms from commercial vendors such as SNL Financial.[5]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Canadian locations were developed by RSMeans. Data on U.S. electric utility construction cost *trends* were purchased from Whitman, Requardt and Associates. Some of the variables used in our econometric cost model were obtained from PSE working papers we examined in the course of this proceeding.

## 3.2 Sample

Data for Hydro One Networks and 44 U.S. transmitters were used in our productivity research. Data for Hydro One and 56 U.S. transmitters were used in our econometric research. The sample period for our econometric cost research was 1995-2016. The extra years should increase the precision of the econometric parameter estimates. The full sample period for our productivity research was 1996-2016. This should produce an MFP trend that is more pertinent to the calibration of X factors for Hydro One SSM and Hydro One Networks.

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[4] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

[5] PSE evidently used SNL Financial data in its research.

## 3.3 Variables Used in the Research

### Costs

The main task of a power transmitter is the long distance transmission of power. This is undertaken at high voltage to reduce line losses. Transmitters typically own substations that reduce the voltage of power before it is delivered to distribution systems. Many transmitters also own substations that increase the voltage of power received from generating stations. The principal assets used in transmission are thus high-voltage power lines, the towers that typically carry them, and substations. Other notable assets include circuit breakers and land.

The cost of power transmitter services considered in our study was the sum of applicable capital costs and OM&A expenses. The capital costs we included were those for transmission plant and a sensible share of the cost of general plant. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains. General issues in the measurement of capital cost are discussed in Appendix section A.2. Further details of our capital cost calculations are provided in Appendix section B.1.

The OM&A expenses we used in the study included most of those reported for power transmission and a sensible share of most administrative and general expenses. We excluded the following categories of transmission OM&A expenses because they have been affected by industry restructuring: transmission by others (account 565), load dispatching (accounts 561-561.8), and miscellaneous transmission expenses (566). We also excluded transmission rent expenses because some utilities used this category to report costs of leases on facilities they jointly own.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses in econometric cost research is the lack of federal labor price indexes that encompass them. On the other hand, Hydro One SSM does not propose to Y factor these expenses. We have excluded pension and benefit expenses from our econometric benchmarking and index research in this proceeding. We also excluded all reported taxes and O&M expenses incurred by the utilities for generation, power procurement, distribution, customer accounts, customer service and information, sales, franchise fees, and gas services.

## Input Prices

O&M

Summary OM&A input price indexes were used in our econometric work that featured subindexes for labor and materials and services. PSE provided the price levels for salaries and wages. Values of each company's labor price index for other years were calculated by adjusting these levels for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For Hydro One Networks, we escalated the level value by average weekly earnings in Ontario as reported by Statistics Canada.

For material and service ("M&S") price inflation in the United States we used the U.S. gross domestic product price index ("GDPPI"). This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products. For the M&S price inflation of Hydro One Networks we used the gross domestic product implicit price index for final domestic demand.

In our econometric work we used a summary OM&A input price index constructed by combining the labor and M&S price subindexes using the 38% labor/62% weights that were calculated by PSE. For the U.S. productivity research, we instead used company-specific, time-varying cost share weights that we calculated from FERC Form 1 OM&A expense data. The summary multifactor input price index for each transmitter in our sample was constructed by combining the capital and summary OM&A price indexes using company-specific, time-varying cost share weights.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research, as we explain in Section B.2 of the Appendix. For the United States rate of return we calculated 50/50 averages of rates of return for debt and equity.[6] For bonds we used the embedded average interest rate on long-term debt as calculated from FERC Form 1 data. For equity we used the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric

[6] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

Institute.[7] For Hydro One Networks, we employed the weighted average cost of capital that PSE used in its study.

As for asset prices, we used the Statistics Canada capital stock deflator for the utility sector to deflate the value of plant additions of Hydro One Networks. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. For the United States utilities we used the regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant.

U.S./Canada Price Patch

Since transnational data were used in the study, it was necessary to make some adjustments for differences in currencies in the two countries. M&S prices were patched using US/Canadian purchasing power parities ("PPPs") computed by the Organization for Economic Cooperation and Development ("OECD"). Construction and labor price indexes did not require a special patch.

## Scale Variables

Two scale variables were used in our econometric cost modelling: length of transmission line and ratcheted maximum peak demand. We used the alternative peak demand data found on page 401b of FERC Form 1 rather than the peak demand data on which PSE relied. Econometric research revealed that a ratcheted peak demand variable constructed using these data had comparable explanatory power to the variable used by PSE. We followed the PSE practice of according the two scale variables a translog treatment by adding quadratic and interaction terms for these variables to the cost model. The translog functional form is discussed further in Appendix Section B.2.

## Other Business Condition Variables

Five other business condition variables were used in our econometric cost model. One of these variables was the extent of transmission plant overheading. This was measured as the share of overhead plant in the gross value of transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves higher O&M expenses since facilities are more

[7] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

exposed to the challenges posed by severe weather (e.g., high winds and ice storms) and flora and fauna. However, capital costs and capex are likely to be lower. The effect on total cost is less clear.

Two variables in the model address dimensions of the transmission system. These are substation capacity per mile of transmission line, and the average voltage of transmission lines. We expect the parameters for both of these variables to have positive signs. The model also includes the construction standards index developed by PSE and the share of transmission plant in the utility's non-general gross plant value. We expect the first variable to have a positive parameter and the second variable to have a negative parameter.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the model. Parameters for such variables have often had a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

## 3.4 Econometric Cost Research

### Econometric Cost Models

We developed an econometric model of the total cost of power transmission. The dependent variable was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.

Results of our econometric work are reported in Table 1. This table includes parameter estimates and their associated asymptotic t values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development.

Table 1

## PEG's Alternative Econometric Model of Transmission Total Cost

**VARIABLE KEY**

| | |
|---|---|
| YM = | Miles of Transmission line |
| D = | Ratched Maximum Demand |
| MVA = | Substation Capacity per Line Mile in 2010 |
| SUB = | Number of transmission substations per km of line |
| VOLT = | Average voltage of transmission line |
| CS = | Construction standards index |
| PCTOH = | Percent of transmission plant overhead |
| PCTPTX = | Percent of transmission plant in total plant |
| Trend = | Time Trend |

| EXPLANATORY VARIABLE | PARAMETER ESTIMATE | T-STATISTIC | P-VALUE |
|---|---|---|---|
| **YM** | 0.436 | 23.615 | 0.00 |
| **YM * YM** | 0.348 | 18.557 | 0.000 |
| **YM * D** | -0.199 | -15.290 | 0.000 |
| **D** | 0.566 | 34.583 | 0.000 |
| **D * D** | 0.230 | 13.164 | 0.000 |
| **MVA** | 0.027 | 3.233 | 0.001 |
| **VOLT** | 0.136 | 10.505 | 0.000 |
| **CS** | 0.542 | 26.962 | 0.000 |
| **PCTPOH** | -1.251 | -11.970 | 0.000 |
| **PCTPTX** | 0.273 | 13.937 | 0.000 |
| **Trend** | 0.000 | 0.143 | 0.886 |
| **Constant** | 12.534 | 164.241 | 0.000 |

| | |
|---|---|
| Rbar-Squared | 0.937 |
| Sample Period | 1995-2016 |
| Number of Observations | 1215 |

Examining the results in the table, it can be seen that the parameters of the business condition variables have sensible signs and parameter values.[8] Our research indicates that the sampled transmission costs of utilities were higher to the extent that:

- ratcheted peak demand was higher
- utilities had longer and higher voltage transmission lines and more substation capacity
- more transmission plant was underground
- transmission plant constituted a larger share of total non-general plant
- construction standards were higher.

The parameter estimates for the scale variables suggest that ratcheted peak demand had a long-run cost elasticity of 0.566% whereas the cost elasticity of transmission line is 0.436%. The adjusted R-squared for the model is 0.937%. The parameter estimate for the trend variable suggests that cost tended to rise over the full sample period by about 0.29% annually for reasons that aren't explained by the business condition variables in the model.

## 3.5 Productivity Research

### Methodology

We calculated indexes of the transmission OM&A, capital, and multifactor productivity of Hydro One Networks and each U.S. utility in our sample. The annual productivity growth rate of each transmitter was calculated as the difference between the growth of its scale and input quantity indexes. Cost-weighted averages of these growth rates were then calculated. This makes sense when calibrating the X factor of a large utility like Hydro One Networks.

The growth of the scale index was a weighted average of the growth in line kilometers and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric research were used to establish weights. The weights were 56.5% for ratcheted maximum peak demand and 43.5% for line length.

[8] This remark pertains to the "first" order terms in the model, and not to the parameters of the translog (squared and interaction) terms. These terms are discussed further in Appendix section B.2.

In calculating input quantity indexes for the U.S. utilities we broke down the applicable cost of U.S. utilities into those for transmission capital, general capital, labor, and M&S inputs. Each of these cost groups had its own input quantity subindex. The trend in each company's multifactor input quantity index is a weighted average of the trends in the four subindexes. The weights on these indexes are company-specific and time-varying. The calculation of the input quantity trend for Hydro One instead used a single, consolidated capital quantity index.

## Industry Trends

Table 2 reports results of our productivity calculations for the full sample. We found that the growth in the transmission MFP of sampled U.S. utilities averaged **-1.82**% over PSE's chosen 2005-2016 sample period but **-0.34**% over the full 1996-2016 sample period during which the effects of formula rates and changing U.S. transmission policies were less pronounced. OM&A productivity growth averaged -1.40% over the shorter sample period but -0.53% over the full period. Transmission capital productivity growth averaged -1.73% over the shorter sample period but -0.21% over the full sample period.

Our estimates of these trends do not reflect any possible improvements in U.S. transmission reliability due to changing federal policies. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. PSE acknowledged in response to OEB staff interrogatory # 63 that reliability can be an output in a productivity study.

## Hydro One Networks' Trends

Table 3 reports results of our transmission productivity calculations for Hydro One Networks. Over the 2005-2016 historical sample period for which Hydro One Networks data are available, the annual MFP growth of the Company averaged -1.21 % while its OM&A productivity growth averaged 0.85% and its capital productivity growth averaged -1.86%. Over the first four years of the proposed plan (2019-2022), the Company's forecasted/proposed costs are consistent with -2.21% average MFP growth, -0.60% OM&A productivity growth, and -2.57% capital productivity growth. The Company's forecasted/proposed costs thus reflect productivity growth that is well below industry trends.

Table 2
U.S. Transmission Productivity Results Using PEG's Methods:
Cost-Weighted Averages

(Growth Rates)[1]

| Year | Scale Index | Input Quantity Index: Summary | Input Quantity Index: O&M | Input Quantity Index: Transmission Capital | Input Quantity Index: Allocated General Plant | Input Quantity Index: Capital | Productivity: MFP | Productivity: O&M | Productivity: Capital | Productivity: Transmission Capital | Productivity: Allocated General Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1996 | 1.19% | -0.66% | -1.08% | -0.73% | -0.16% | -0.69% | 1.85% | 2.26% | 1.88% | 1.92% | 1.35% |
| 1997 | 0.85% | -1.28% | -0.16% | -0.80% | -5.16% | -0.89% | 2.13% | 1.01% | 1.74% | 1.64% | 6.00% |
| 1998 | 1.47% | -0.95% | 0.35% | -1.50% | 1.10% | -1.41% | 2.41% | 1.12% | 2.88% | 2.97% | 0.37% |
| 1999 | 1.50% | -1.67% | -6.28% | -1.38% | -3.27% | -1.45% | 3.16% | 7.78% | 2.95% | 2.88% | 4.76% |
| 2000 | 0.67% | 0.14% | 6.58% | -0.79% | 7.94% | -0.61% | 0.54% | -5.90% | 1.28% | 1.47% | -7.26% |
| 2001 | 1.63% | -0.03% | 1.85% | -0.54% | 15.31% | -0.22% | 1.66% | -0.21% | 1.85% | 2.18% | -13.68% |
| 2002 | 1.42% | -0.97% | -4.72% | -0.24% | -7.58% | -0.31% | 2.39% | 6.13% | 1.73% | 1.65% | 8.99% |
| 2003 | 1.51% | 0.00% | 3.36% | -0.53% | 0.91% | -0.49% | 1.51% | -1.84% | 2.00% | 2.04% | 0.60% |
| 2004 | 0.33% | 1.21% | 4.90% | 0.28% | 3.36% | 0.34% | -0.89% | -4.58% | -0.01% | 0.05% | -3.03% |
| 2005 | 2.41% | 1.55% | 6.41% | 0.33% | 1.52% | 0.36% | 0.86% | -4.00% | 2.05% | 2.09% | 0.90% |
| 2006 | 1.73% | 0.93% | 2.19% | 0.37% | -4.87% | 0.22% | 0.80% | -0.45% | 1.52% | 1.36% | 6.60% |
| 2007 | 1.05% | 1.90% | 3.89% | 1.31% | -4.48% | 1.07% | -0.85% | -2.84% | -0.02% | -0.26% | 5.53% |
| 2008 | 0.44% | 2.17% | 4.35% | 1.36% | 3.84% | 1.44% | -1.74% | -3.91% | -1.01% | -0.93% | -3.40% |
| 2009 | -0.17% | 2.61% | 3.27% | 2.47% | 0.48% | 2.38% | -2.78% | -3.44% | -2.55% | -2.64% | -0.65% |
| 2010 | 0.64% | 2.76% | 5.60% | 1.91% | -0.48% | 1.80% | -2.11% | -4.96% | -1.15% | -1.27% | 1.12% |
| 2011 | 0.32% | 1.31% | -2.43% | 2.48% | -1.49% | 2.36% | -0.99% | 2.75% | -2.03% | -2.16% | 1.81% |
| 2012 | 0.57% | 2.05% | 2.89% | 1.79% | 7.05% | 1.86% | -1.47% | -2.31% | -1.28% | -1.22% | -6.48% |
| 2013 | 0.27% | 4.13% | 2.61% | 4.56% | 8.66% | 4.56% | -3.87% | -2.34% | -4.29% | -4.29% | -8.40% |
| 2014 | 0.84% | 3.36% | -3.37% | 4.56% | -2.26% | 4.41% | -2.51% | 4.22% | -3.57% | -3.71% | 3.10% |
| 2015 | 0.61% | 3.61% | -2.90% | 4.75% | 2.38% | 4.74% | -3.00% | 3.50% | -4.13% | -4.15% | -1.77% |
| 2016 | -0.06% | 4.11% | 2.94% | 4.22% | 5.69% | 4.21% | -4.17% | -3.00% | -4.28% | -4.28% | -5.75% |
| **Average Annual Growth Rates** | | | | | | | | | | | |
| **1996-2016** | **0.91%** | **1.25%** | **1.44%** | **1.14%** | **1.36%** | **1.13%** | **-0.34%** | **-0.53%** | **-0.21%** | **-0.22%** | **-0.44%** |
| **2005-2016** | **0.72%** | **2.54%** | **2.12%** | **2.51%** | **1.34%** | **2.45%** | **-1.82%** | **-1.40%** | **-1.73%** | **-1.79%** | **-0.62%** |

[1]All growth rates are calculated logarthmically.

## 3.6 Cost Benchmarking Results

PEG used its own econometric cost model to benchmark the total transmission cost of Hydro One Networks. We used PSE's forecasts for the input prices. Results of our benchmarking work are presented in Table 4. It can be seen that the Company's transmission cost was about 9.43% below the model's prediction on average from 2014 to 2016, the three most recent historical years for which data are available. The Company's forecasted/proposed total costs are about 1.23% below the model's prediction on average during the first four years of the proposed IRM (2019-2022). This research suggests that the Company is an average cost performer.

Table 3

Hydro One Networks' Transmission Productivity Annual Growth Rates

| Year | Multifactor Productivity | OM&A Productivity | Capital Productivity | Output Quantity | OM&A Input Quantity | Capital Input Quantity |
|---|---|---|---|---|---|---|
| 2005 | 3.51% | 11.61% | 1.13% | 1.52% | -10.09% | 0.39% |
| 2006 | -0.31% | -7.69% | 2.04% | 1.96% | 9.65% | -0.08% |
| 2007 | -4.04% | -10.39% | -1.71% | 0.00% | 10.39% | 1.71% |
| 2008 | 3.86% | 14.73% | -0.42% | 0.08% | -14.66% | 0.50% |
| 2009 | -5.54% | -12.06% | -2.68% | -0.01% | 12.06% | 2.67% |
| 2010 | -2.30% | 1.54% | -4.03% | 0.04% | -1.50% | 4.06% |
| 2011 | -1.28% | 3.90% | -3.19% | 0.04% | -3.86% | 3.23% |
| 2012 | -4.30% | 0.34% | -5.69% | 0.41% | 0.07% | 6.10% |
| 2013 | -1.84% | -2.32% | -1.70% | 0.03% | 2.35% | 1.73% |
| 2014 | 0.07% | 10.86% | -3.04% | -0.05% | -10.91% | 2.99% |
| 2015 | -2.87% | -10.09% | -0.69% | 0.14% | 10.22% | 0.83% |
| 2016 | 0.49% | 9.74% | -2.29% | 0.00% | -9.74% | 2.29% |
| 2017 | -1.05% | 4.97% | -2.56% | -0.54% | -5.51% | 2.02% |
| 2018 | -1.77% | 4.04% | -3.06% | 0.58% | -3.46% | 3.63% |
| 2019 | -1.93% | -2.75% | -1.76% | 0.00% | 2.75% | 1.76% |
| 2020 | -2.26% | 0.13% | -2.79% | 0.00% | -0.13% | 2.79% |
| 2021 | -2.27% | 0.10% | -2.80% | 0.01% | -0.10% | 2.81% |
| 2022 | -2.39% | 0.11% | -2.94% | 0.01% | -0.10% | 2.94% |
| **Average Annual Growth Rates** | | | | | | |
| **2005-2016** | **-1.21%** | **0.85%** | **-1.86%** | **0.35%** | **-0.50%** | **2.20%** |
| **2010-2016** | **-1.62%** | **2.07%** | **-2.77%** | **0.10%** | **-1.98%** | **2.86%** |
| **2019-2022** | **-2.21%** | **-0.60%** | **-2.57%** | **0.00%** | **0.61%** | **2.58%** |

Table 4

## Transmission Total Cost Performance of Hydro One Networks Using the PEG Econometric Model

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

| Year | Cost Benchmark Score |
|---|---|
| 2004 | -23.40% |
| 2005 | -27.00% |
| 2006 | -26.40% |
| 2007 | -21.90% |
| 2008 | -24.80% |
| 2009 | -18.70% |
| 2010 | -17.00% |
| 2011 | -16.90% |
| 2012 | -13.40% |
| 2013 | -11.20% |
| 2014 | -11.30% |
| 2015 | -8.00% |
| 2016 | -9.00% |
| 2017 | -8.10% |
| 2018 | -6.70% |
| 2019 | -4.70% |
| 2020 | -2.30% |
| 2021 | -0.10% |
| 2022 | 2.20% |
| **Average 2004-2016** | **-17.62%** |
| **Average 2014-2016** | **-9.43%** |
| **Average 2019-2022** | **-1.23%** |

[1] Formula for benchmark comparison is $\ln(Cost^{HON}/Cost^{Bench})$.

# 4. Stretch Factor and X Factor Recommendations

## 4.1 Stretch Factor

We disagree with PSE's 0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted because Hydro One Networks is a superior transmission cost performer and there is a large implicit stretch factor. One reason that we disagree is that the plan is for Hydro One SSM and no evidence has been submitted on this company's cost performance. Another and more important reason is that Hydro One Networks' cost performance does not score as well in our study as in the PSE study. A third is that transmission MFP growth is more rapid using our longer sample period and methods.

In addition, we have long believed that, in addition to utility operating efficiency, stretch factors should reflect the difference between the incentive power of the contemplated IRM and the incentive power of the regulatory systems under which utilities in studies used to set the base productivity trend operated. Hydro One SSM proposes to operate under a lengthy multiyear rate plan with limited earnings sharing whereas the formula rate plans and special incentives that many sampled U.S. electric utilities operated under during the years of the productivity studies materially weakened their cost containment incentives.

We have developed an incentive power model with funding from many clients over the years that include the OEB. This model considers the response of a typical pipe or wires utility to operation under alternative stylized regulatory systems. Based on the formula rates alone this model suggests that, if the base productivity trend were based on U.S. data for the 2005-2016 sample period that PSE uses, the indicated stretch factor would lie in the [**0.50** – **1.01**] range for a company with average cost performance. Our incentive power research is discussed further in the Appendix Section B.4.

## 4.2 X Factor

We recommend that the **-0.34**% trend in the MFP of the U.S. power transmission industry over the full sample period serve as the base productivity trend. This estimate may be understated because it does not reflect any possible improvements in U.S. transmission reliability due to changing federal policies. A **0.30**% stretch factor is warranted if results for our full sample period are used. With rounding, our X factor recommendation is **0.00%.**

# Appendix A: Index Research for X Factor Calibration

In this section of the report we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other important methodological issues.

## A.1 Principles and Methods for Revenue Cap Index Design

### Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design revenue cap escalators. To review this logic, it may be helpful to ensure that the reader has a high-level understanding of some basic tools of index research.

Input Price and Quantity Indexes

The growth (rate) of a company's cost can be shown to be the sum of the growth of a (cost-weighted) input price index ("Input Prices") and input quantity index ("Inputs").

*growth Cost = growth Input Prices + growth Inputs*.[9] [A1]

Both of these indexes are typically multidimensional in the sense that they summarize trends in subindexes that are appropriate for particular subsets of cost. The major input groups of a power transmitter include capital, labor, and materials and services.

Productivity Indexes

*The Basic Idea* A productivity index is the ratio of a scale index ("Scale") to an input quantity index.

$$Productivity = \frac{Scale}{Inputs}. \qquad [A2]$$

It can be used to measure the efficiency with which firms use inputs to achieve their scale of operation.

Some productivity indexes are designed to measure productivity *trends*. The growth of such a productivity index is the difference between the growth in the scale and input quantity indexes.

*growth Productivity = growth Scale – growth Inputs*. [A3]

[9] Cost-weighted input price and quantity indexes are attributable to the French economist Francois Divisia.

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. The productivity growth of utilities can be volatile but has historically tended to be positive over long time periods. The volatility is typically due to demand-driven fluctuations in operating scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be much greater for individual companies than the average for a group of companies.

Relations [A1] and [A3] imply that

*growth Productivity = growth Scale* – (*growth Cost - growth Input Prices*)

*= growth Input Prices - growth* (*Cost/Scale*).

Productivity growth is thus the amount by which a firm's unit cost grows more slowly than its input prices.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input group such as labor. A *multifactor* productivity index measures productivity in the use of various kinds of inputs. MFP indexes are sometimes called *total* factor productivity ("TFP") indexes, a term that is widely used but often incorrect because some inputs are excluded from the index calculations.

*Scale Indexes* A scale index of a firm or industry summarizes trends in the scale of operation. These indexes may also be multidimensional. Growth in each dimension of scale that is itemized is then measured by a subindex and the scale index summarizes growth in the subindexes by taking a weighted average of them.

In designing a scale index, choices concerning scale variables (and weights, if the index is multidimensional) should depend on the manner in which the index is used. One possible objective is to measure the impact of growth in scale on *revenue*. In that event, the scale variables should measure growth in *billing determinants* like peak demand and the weight for each itemized determinant should be its share of a utility's base rate revenue.[10]

Another possible objective of scale indexing is to measure growth in dimensions of scale that affect *cost*. In that event, the scale variable(s) should measure dimensions of the "workload" that drive

[10] Revenue-weighted scale indexes are attributable to the French economist Francois Divisia.

cost. If there is more than one scale variable in the index the weight for each variable should reflect its relative cost impact. 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 of utilities can be estimated econometrically using a sample of data on the costs and operating scale of a group of utilities. These estimates can provide the basis for scale index weights.[11] We denote a productivity index calculated using a cost-based scale index will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Scale^C - growth\ Inputs. \qquad [A4]$$

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

## Use of Index Research in Revenue Cap Design

Productivity studies have many uses, and the best research methods for one use may not be best for another. In this section, we discuss the logic for using productivity research in revenue cap index design and consider some implications for the appropriate productivity index.

### Revenue Cap Indexes

We begin our explanation of the supportive index logic by considering the growth in the revenue of a firm that earns, in the long run, a competitive rate of return.[12] For such a firm, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [A5]$$

Consider now the following basic result of cost theory:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^C + growth\ Scale^C.^{13} \qquad [A6a]$$

[11] A multidimensional scale index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

[12] 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.

[13] This result can be 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.

The growth in the cost of a firm is the difference between the growth in input price and cost efficiency indexes plus the trend in a (consistent) cost-based scale index. This result provides the basis for revenue cap indexes of general form

$$growth\ Revenue = growth\ Input\ Prices - X + growth\ Scale^C \qquad [A6b]$$

where

$$X = trend\ \overline{Productivity^C} + Stretch. \qquad [A6c]$$

Here *trend Productivity*$^C$ is the trend in the productivity indexes of a sample of utilities and *Stretch* is the stretch factor. Notice that a cost-based scale index should be used in the supportive productivity research for a revenue cap index X factor. Moreover, this index should match the scale index in the revenue cap index.

Sample Period

Another important issue in the design of a revenue (or price) cap index is whether it should be designed to track short-run or long-run industry cost trends. Indexes designed to track short-run growth will also track the long run growth trend if this approach is used repeatedly over many years. An alternative approach is to design the index to track only long-run trends.

Different approaches can, in principle, be taken for the input price and productivity components of the revenue cap index and are in most cases warranted. The inflation measure should track short-term input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current long-run productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in operating scale and inputs which are not expected to continue. The long-run productivity trend is faster than the short-run trend during a short-lived surge in input growth but slower than the trend during a short-lived lull in input growth.

This general approach to revenue cap index design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the revenue cap index responsive to short-term input price growth reduces the operating risk of the utility without weakening its performance incentives. Having X reflect the long-run industry productivity trend, meanwhile, sidesteps the need for more timely cost data and annual productivity calculations.

In order to calculate the long-run productivity trend using indexes, it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of current business conditions. Moreover, quality data are sometimes not readily available for longer sample periods. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the scale index does not assign a heavy weight to volatile scale variables.

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[14] The 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.

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.

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 accelerate to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is smaller the greater is its current efficiency level.

System age can drive productivity growth in the short and medium run. For example, 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 has a need for unusually high replacement capex, capital productivity can decline. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates.

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 transmitter is a change in the mix of overhead and underground lines.

[14] Denny, Fuss, and Waverman (1981), referenced above, provides a classic discussion of the drivers of productivity growth.

## A.2 Key Things to Know About Capital Cost Research

### Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost specification is of central importance in research on the MFP of power transmission because its technology is capital-intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in North American productivity research. A monetary approach decomposes capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WKS*") such that

$$CK = WKS \cdot XK.^{15} \quad [A7]$$

The capital quantity index is constructed using inflation-adjusted data on the value of utility plant.

It is customary to assume that a capital good provides a stream of services over a period of time that is called the service life of the asset. *XK* is then construed to measure the quantity of this stream. The capital service price index measures the trend in the price of a unit of capital service. In research on the productivity of U.S. energy utilities, Handy Whitman utility construction cost indexes and data on the rate of return on utility capital have traditionally been used in capital price index construction. The product of the capital service price index and the capital quantity index is the annual cost of using the flow of services.

### Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification 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.

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[15] The *growth rate* of capital cost is thus the sum of the growth rates of the capital price and quantity indexes.

For the earlier years that are pertinent, the desired gross plant addition data are frequently unavailable. It is then customary to take the value of plant of every vintage at the end of this limited-data period and then estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical plant addition 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.

## Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice of a monetary method is the pattern of decay in the quantity of capital after a plant addition.[16] Another issue is whether plant is valued in historic dollars or replacement dollars.

Three monetary methods have been used in North American research to calibrate utility X factors.

- Under the geometric decay ("GD") specification, the flow of services from investments in a given year declines at a constant rate over time. Plant is valued in replacement (i.e., *current*) dollars. This general method has been most commonly used in X factor calibration studies. Replacement valuation differs from the historical (i.e., "book") valuation used in North American utility accounting and requires consideration of capital gains.
- Under the one hoss shay specification, the flow of services from plant additions in a given year is assumed to be constant until the end of their service lives, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. Plant is once again valued at replacement cost and capital gains are considered.

  The cost of service ("COS") method is designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. Capital gains are not considered.

[16] The pattern of decay over time is sometimes called the age-efficiency profile.

# Appendix B: Further Detail on Select Topics

## B.1 Technical Details of PEG's Productivity Research

This section of Appendix B contains more technical details of our productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our methods for calculating input price inflation and capital cost.

### Input Quantity Indexes

The growth rate of a summary (multidimensional) input quantity index is defined by a formula that involves subindexes measuring growth in the quantities of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

We have constructed summary multifactor and OM&A input quantity indexes. Each summary input quantity index is of chain-weighted Törnqvist form.[17] This means that its annual growth rate is determined by the following general formula:

$$\ln\left( \frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left( sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left( \frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [B1]$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

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[17] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

## Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Scale_t}{Scale\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [B2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

## Input Price Indexes

The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

### Price Index Formulas

The multifactor input price index used in the econometric total cost model was of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left(Input\ Prices_t / Input\ Prices_{t-1}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(W_{j,t} / W_{j,t-1}\right). \qquad [B3]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$Sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

## Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Appendix section A.2 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data available and previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each utility in 1964 depends on the net value of its plant as reported in FERC Form 1. We estimated the benchmark year quantity of capital by dividing this book value by a triangularized weighted average of 46 values of an index of power transmission construction cost for a period ending in the benchmark year. The construction cost indexes ($WKA_t$) were developed from the applicable regional Handy-Whitman indexes of cost trends of electric utility transmission construction.[18] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [B4]$$

Here, the parameter *d* is the economic depreciation rate and $VI_t$ is the value of gross additions to utility plant. The assumed 46-year average service life and 1.65 declining balance rate that were used to set d are the same as in the PSE study.

The formula for the corresponding GD capital service price indexes used in the research was

[18] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

$$WKS_{j,t}=[CK_{j,t}^{Taxes}/XK_{j,t-1}]+d\cdot WKA_{j,t}+WKA_{j,t-1}\left[r_t-\frac{\left(WKA_{j,t}-WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \quad [B5]$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

## B.2 Econometric Research

This section of Appendix B provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

### Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t}=a_0+a_1\cdot N_{h,t}+a_2\cdot V_{h,t}. \quad [B6]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t}=a_0+a_1\cdot\ln N_{h,t}+a_2\cdot\ln V_{h,t}. \quad [B7]$$

The double log model is so-called because the right- and left-hand side variables are all logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter $a_1$ indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t}= a_o + a_1\cdot\ln N_{h,t} + a_2\cdot\ln V_{h,t} + a_3\cdot\ln N_{h,t}\cdot\ln N_{h,t} + a_4\cdot\ln V_{h,t}\cdot\ln V_{h,t} + a_5\cdot\ln V_{h,t}\cdot\ln N_{h,t} \quad [B8]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $lnN_{h,t} \cdot lnN_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $lnV_{h,t} \cdot lnN_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that is logarithmic only with respect to the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the quadratic terms in our model had statistically significant parameter estimates.

## Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in Table 1 above therefore vary slightly from those in the models used for benchmarking.

## B.3 Federal Regulation of U.S. Power Transmission

In the United States, regulation of power transmission rates is undertaken today chiefly by the FERC. It is important to understand how this regulation has evolved.

### Unbundling Transmission Service

Transmission regulation prior to the mid-1990s reflected the vertically integrated structure of most investor-owned electric utilities in that era. These utilities typically owned both the transmission and the distribution systems in the areas they served and obtained most of their power supplies from their own generation facilities. There were fewer bulk power purchasers and independent power producers using transmission services than there are today.

Wholesale customers (e.g., municipal utilities) could obtain bundled generation and transmission services from adjacent utilities by negotiating a contract with the utility. Power was sometimes purchased from a third party and delivered over other companies' transmission system. If the contract path for such a purchase passed over multiple transmission systems the customer might have to pay multiple transmitters for service, a phenomenon called “pancaked rates”. Disputes over wholesale contracts for the purchase and transmission of power could be brought to the FERC. Utilities sometimes had the ability to discriminate between their customers regarding the terms of transmission service.

Starting in the 1970s, federal legislation increasingly encouraged proliferation of 3$^{rd}$ party generators and the development of more robust bulk power markets. This increased the demand for public, non-discriminatory tariffs for wholesale transmission service. In 1996, FERC Order 888 required transmitters to provide service under open access transmission tariffs (“OATTs”). To ensure that service was provided on a non-discriminatory basis, the FERC also ordered transmitters to establish an information network to provide network information to transmission customers and procure its native load transmission service solely using the OATT and the publicly available information network. Third parties were provided the option to procure the same types of service at the same quality levels as the transmitter’s native load. Many details of functional unbundling and the information service for transmission customers were addressed in FERC Order 889.

Bulk power markets were also expanded by restructuring of retail markets in many American states. This permitted a larger role for independent power merchandizers and bulk power market purchases by large industrial customers.

## Formula Rates

Rates for jurisdictional transmission services can be set by the FERC in periodic rate cases. Transmitters also have the option to request formula rates, wherein rates are reset annually to reflect the changing cost of their service. Formula rates may rely on a transmitters historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Early FERC rationales for using formula rates included the following.[19]

- Establishment of rates for a new utility;
- Establishment of rates for the transaction of one utility with an affiliated utility; and
- Economies in regulatory cost.

Regulatory cost economies are a major consideration for a commission with jurisdiction over more than 100 electric utilities and dozens of interstate oil and gas pipelines.

Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies such as the Energy Policy Act of 2005 which promoted transmission investment and increased attention to reliability. Early adopters of formula rates included Midwestern and New England utilities and the Southern Company. Many of the FRPs approved by the FERC have been the product of settlements.

[19] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

At the 2004 start date of PSE's sample period less than 15 of the 56 sampled transmitters operated under formula rates. By the 2016 end point of PSE's sample period fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during PSE's sample period. Thus, about half of the U.S. transmitters in the PSE sample received approval of formula rate plans during the PSE sample period.

## ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission systems to an independent system operator ("ISO"). In this arrangement, the transfer of control was voluntary and utilities retained ownership of their portions of the grid. ISOs have scheduled services, managed transmission facility maintenance, provided transmission system information to all potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services must be provided under an OATT that is not discriminatory to any market participant. These tariffs recover the ISO's cost, which sometimes including the sizable charges of transmission owners for the use of their systems.

In a 1999 order, the FERC pushed for further structural change in the markets for transmission services by encouraging formation of RTOs. The FERC has higher requirements for RTO approval than for ISOs. For example, RTO tariffs must include the transmission owners' cost. RTOs also typically have a larger footprint, serving multiple states while some ISOs serves a single state or Canadian province.

Several ISOs were formed between 1996 and 2000. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the US. The Midwestern ISO (dba today as Midcontinent ISO) and PJM Interconnection were approved for RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs currently operate in some Canadian provinces, New York, Texas, and California.[20] Relatively few utilities in the southeastern and intermountain states are members of an ISO or RTO.[21]

[20] Texas transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[21] In recent years, several South Central U.S. transmitters joined MISO.

The charges of transmission owners who are members of RTOs may still be reset in periodic rate cases or formula rate plans. All Midcontinent ISO transmission owners have formula rates.

## Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex began to decline in real terms. Part of this decline was due to low generation plant additions, particularly in the late 1990s. Other reasons given for the decline in capex were difficulties in siting transmission lines and poor incentives for transmitters to propose new lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion costs occurred in some areas. The decline in capex eventually led to concerns by the FERC and other policymakers that transmitters were not sufficiently investing in their networks, thus jeopardizing the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 was passed. It affected transmission investment and many other aspects of transmitter operations. The Act gave the FERC authority to oversee transmission reliability. The FERC could sanction mandatory reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"). Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability issues resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators.

Concerns about siting of transmission lines were somewhat mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to mitigate areas of significant transmission congestion. This provision has proven to be somewhat controversial, as it is viewed as a federal intrusion into an issue that states have traditionally addressed. Nevertheless, it is likely that potential federal oversight of transmission siting encouraged state regulators to expedite transmission siting proceedings.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission investments and participation in an RTO or ISO. The Energy Policy Act of 2005 required FERC to adopt a rule that would accomplish the following:

> ''(1) promote reliable and economically efficient transmission and generation of electricity **by promoting capital investment in the enlargement, improvement, maintenance, and operation**

**of all facilities for the transmission of electric energy in interstate commerce**, regardless of the ownership of the facilities;

''(2) **provide a return on equity that attracts new investment in transmission facilities** (including related transmission technologies);

''(3) **encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities**; and

''(4) allow recovery of—

> ''(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
>
> ''(B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[22]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. These incentives included the ability for a transmitter to include 100% of CWIP in rate base, ROE premiums for plant additions resulting from some projects (one that is set above the middle of the zone of reasonableness), accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking of individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied into a request by a transmitter to switch from a fixed rate adjusted only in a rate proceeding to a formula rate that is updated annually. Between 2006 and 2012, the FERC reviewed more than 80 applications for transmission incentives related to proposed projects.

## B.4 Insights from Incentive Power Research

PEG Research has for many years undertaken research on the incentive power of alternative regulatory systems. The work has been sponsored by numerous utilities and regulatory agencies,

[22] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

including the OEB, two Canadian gas distributors, and the Essential Services Commission in the Australian state of Victoria. Incentive power research can be used to explore IRM design options such as plan terms and earnings sharing mechanisms. Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the University of Texas.

This Appendix section first presents a non-technical discussion of the methods used in our incentive power research. We then discuss some pertinent research results.

## Overview of Research Program

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions that resemble those of a typical energy distributor. In the first year of the decision problem, the total annual cost of the company's base rate inputs is around $500 million for a company of average efficiency. Capital accounts for a little more than half of this cost. The annual depreciation rate is 5%, the weighted average cost of capital is 7%, and the income tax rate is 30%.[23]

Some assumptions are made to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time. Under these assumptions, the utility's revenue will be the same year after year in the absence of a rate case. There is thus no need for complicated adjustments in rate cases to the costs incurred in historical reference years or for attrition relief mechanisms between rate cases.

The company is assumed to have opportunities to reduce its cost of service through cost reduction effort. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years, and five years, respectively. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we currently consider eight kinds of projects, four for OM&A expenses and four for capex. The company is permitted to pass up each kind of project in a given year but cannot

[23] The comparatively low WACC reflects our assumption that there is no input price inflation.

choose *negative* levels of effort that amount, essentially, to deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

Companies can increase earnings by undertaking cost containment projects, but the company experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed for simplicity to occur up front. We have assigned these a value, in the reckonings of employees, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings in a given year, less the distress costs of performance improvement, given the regulatory system, the income tax rate, and the available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Regulatory Systems

Regarding the regulatory systems considered, we have developed five "reference" systems that constitute useful comparators for multiyear rate plans. One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost. Another is a full externalization of rates, such as might obtain if the company were to embark on a permanent revenue cap regime with no prospect for future cost-based revenue requirement true-ups.

The other three reference regimes try to approximate traditional regulation. In each, there is a predictable rate case cycle. We consider rate case cycles of one, two, and three years.

Various multiyear rate plans can be considered using our research method. All are revenue cap plans. The plans differ with respect to three kinds of plan provisions. One is the term of the plan. We consider terms of five, six, and ten years. There is no stretch factor shaving the revenue requirement mechanistically from year to year.

Plans considered vary, secondly, with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are 0%, 25%, 50%, and 75%. We will refer to a rate plan that lacks an earnings sharing mechanism as a "basic" rate plan. None of the mechanisms considered have dead bands, as these complicate the calculations. This limits the relevance of the results since many approved mechanisms do have dead bands. An ESM with a 25% company share may generate performance incentives similar to those of a real-world ESM with a dead band.

Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle. The qualification is that any up-front *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan. This reduces the incentive for the utility to time cost reduction projects to occur in the reference year.

We have also considered the impact of some stylized efficiency carryover mechanisms. In one mechanism the revenue requirement at the start of a new plan is based $\alpha\%$ on the cost in the last year of the previous plan and $(1-\alpha)\%$ on the revenue requirement in that year. This effectively permits the company to share $(1-\alpha)\%$ of any deviation between its cost and the revenue requirement. We consider alternative values of $\alpha$, ranging from 90% to 50%. [Thus, the externalized share ranges from 10% to 50%].

We also considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance resulting from a benchmarking appraisal that is completely unrelated to past revenue requirements. We suppose that

$$Requirement_t = Cost_{t-1} + Carryover_{t-1}$$

where the carryover is $\alpha\%$ of the difference between a benchmark for cost in period t-1 and the actual cost that was incurred.

$$Carryover_t = \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

Then

$$Requirement_t = Cost_{t-1} + \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

$$= \alpha \times Benchmark_{t-1} + (1-\alpha) \times Cost_{t-1}$$

The revenue requirement for the first year of the new PBR plan thus depends only $(1-\alpha)\%$ on the cost of service in year t-1. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

We have also considered a novel approach to incenting long-term efficiency gains which we will call the "revenue option" approach. It gives the company the option to trade a revenue requirement, for the first year of the next rate plan, which is established by conventional means for a revenue requirement that is established on the basis of a predetermined formula. The formula that we consider is a stretch factor reduction in the revenue requirement that is established in the first year of the preceding rate case.[24]

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

### Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function.

One advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism. Another is that it facilitates review of our research by stakeholders. The numerical analysis is intuitively appealing, and verification can focus less on how results are derived and more on how sensible and thorough is our characterization of cost containment opportunities and alternative regulatory systems.

## Research Results

Some results of our incentive power research are found in Tables B1-B3. For each of several hypothetical regulatory systems, each table shows the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the table we report

[24] In a world of input price and output growth, a more complex formula would be required.

the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second plans and the long run and discuss here only the long run results.

Results are presented for 10%, 30% and 50% levels of initial operating efficiency. We focus here on the 30% results since our statistical benchmarking research over the years suggests that this is a normal level of operating efficiency. The 30% results can be found in Table B1.

### Results for Reference Regulatory Systems

Inspecting the results for the reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under true cost plus regulation. This reflects the fact that there is no monetary reward for undertaking these initiatives, all of which involve some kind of cost. At the other extreme, a complete externalization of future rates produces performance improvements relative to cost plus regulation that, over many years, accumulate to an NPV of more than $2 billion.

As for the traditional regulatory systems, U.S. electric utilities typically file a rate case every three years. Table B1 shows that a three-year rate case cycle incents the company to achieve long-run savings with an NPV of about $899 million ---a major improvement over cost plus regulation but less than half of those that are potentially available. Average annual productivity gains rise from 0% to 0.90%. The fact that some cost savings occur under traditional regulation isn't surprising inasmuch as a three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects to achieve more lasting efficiencies which have shorter payback periods.

### Impact of Plan Term

Consider now the effect of extending the plan term beyond the three-year rate case cycle. It can be seen that extending the term from three years to the five-year cycle that is typical in Ontario substantially increases the net present value of cost savings. In the absence of earnings sharing, the average annual performance gain increases by 51 basis points in the longer run. Half of this figure is about 25 basis points.

## Table B1
# Results from the Incentive Power Model

| **30%** initial inefficiency | Net Present Value ($m) of Cost Redutions | Relative Incentive Power | Average Annual Performance Gain* | |
|---|---|---|---|---|
| | | | First two rate cycles | Long run |
| **Reference Regulatory Options** | | | | |
| Cost plus | 0 | **0%** | 0.00% | 0.00% |
| 2 Year Cost of Service | 657 | **29%** | 1.19% | 0.66% |
| 3 Year Cost of Service | 899 | **39%** | 1.22% | 0.90% |
| Full Rate Externalization | 2299 | **100%** | 3.93% | 2.71% |
| | | | | |
| **Impact of Plan Term** | | | | |
| Term = 3 years | 899 | **39%** | 1.22% | 0.90% |
| Term = 5 years | 1318 | **57%** | 1.93% | 1.41% |
| Term = 6 years | 1428 | **62%** | 1.96% | 1.58% |
| Term = 10 years | 1664 | **72%** | 2.35% | 2.23% |
| | | | | |
| **Impact of Earnings Sharing Mechanism** | | | | |
| 5-year plans | | | | |
| No Sharing | 1318 | **57%** | 1.93% | 1.41% |
| Company Share = 75% | 1075 | **47%** | 1.29% | 1.17% |
| Company Share = 50% | 966 | **42%** | 1.14% | 1.01% |
| Company Share = 25% | 879 | **38%** | 1.03% | 0.88% |
| | | | | |
| **Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)** | | | | |
| 3-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 899 | **39%** | 1.93% | 0.90% |
| Externalized Percentage = 10% | 990 | **43%** | 1.29% | 1.07% |
| Externalized Percentage = 25% | 1336 | **58%** | 1.80% | 1.66% |
| Externalized Percentage = 50% | 1799 | **78%** | 3.41% | 2.15% |
| | | | | |
| 5-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 1318 | **57%** | 1.93% | 1.41% |
| Externalized Percentage = 10% | 1469 | **64%** | 2.07% | 1.55% |
| Externalized Percentage = 25% | 1598 | **70%** | 2.30% | 1.76% |
| Externalized Percentage = 50% | 1989 | **86%** | 3.00% | 2.27% |
| | | | | |
| **Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)** | | | | |
| 3-Year Plans | | | | |
| Externalized Percentage = 0% | 899 | **39%** | 1.93% | 0.90% |
| Externalized Percentage = 10% | 1535 | **67%** | 2.26% | 1.93% |
| Externalized Percentage = 25% | 1824 | **79%** | 3.68% | 2.29% |
| Externalized Percentage = 50% | 2016 | **88%** | 3.84% | 2.54% |
| | | | | |
| 5-Year Plans | | | | |
| Externalized Percentage = 0% | 1318 | **57%** | 1.93% | 1.41% |
| Externalized Percentage = 10% | 1621 | **70%** | 2.34% | 1.80% |
| Externalized Percentage = 25% | 1908 | **83%** | 3.08% | 2.31% |
| Externalized Percentage = 50% | 2109 | **92%** | 3.57% | 2.56% |
| | | | | |
| **Rate Option Plans** | | | | |
| 3-Year Plans | | | | |
| No rate option | 899 | **39%** | 1.93% | 0.90% |
| Yearly rate reduction = 1% | 2299 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 1.5% | 2299 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 2% | 2299 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 2.5% | 899 | **39%** | 1.93% | 0.90% |
| | | | | |
| 5-Year Plans | | | | |
| No rate option | 1318 | **57%** | 1.93% | 1.41% |
| Yearly rate reduction = 1% | 2299 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 1.5% | 2299 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 2% | 1318 | **57%** | 1.93% | 1.41% |
| Yearly rate reduction = 2.5% | 1318 | **57%** | 1.93% | 1.41% |

*** = measured by the average year-over-year percent decrease in costs**

## Table B2
# Results from the Incentive Power Model

| **10%** initial inefficiency | Net Present Value ($m) of Cost Redutions | Relative Incentive Power | Average Annual Performance Gain* | |
|---|---|---|---|---|
| | | | First two rate cycles | Long run |
| **Reference Regulatory Options** | | | | |
| Cost plus | 0 | **0%** | 0.00% | 0.00% |
| 2 Year Cost of Service | 436 | **29%** | 1.08% | 0.57% |
| 3 Year Cost of Service | 623 | **42%** | 1.02% | 0.76% |
| Full Rate Externalization | 1496 | **100%** | 2.64% | 2.32% |
| **Impact of Plan Term** | | | | |
| Term = 3 years | 623 | **42%** | 1.02% | 0.76% |
| Term = 5 years | 811 | **54%** | 1.10% | 1.15% |
| Term = 6 years | 976 | **65%** | 1.19% | 1.30% |
| Term = 10 years | 1088 | **73%** | 1.48% | 1.73% |
| **Impact of Earnings Sharing Mechanism** | | | | |
| 5-year plans | | | | |
| No Sharing | 811 | **54%** | 1.10% | 1.15% |
| Company Share = 75% | 723 | **48%** | 0.97% | 0.97% |
| Company Share = 50% | 653 | **44%** | 0.87% | 0.84% |
| Company Share = 25% | 602 | **40%** | 0.83% | 0.73% |
| **Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)** | | | | |
| 3-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 623 | **42%** | 1.02% | 0.76% |
| Externalized Percentage = 10% | 672 | **45%** | 1.09% | 0.87% |
| Externalized Percentage = 25% | 887 | **59%** | 1.32% | 1.36% |
| Externalized Percentage = 50% | 1123 | **75%** | 1.87% | 1.80% |
| 5-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 811 | **54%** | 1.10% | 1.15% |
| Externalized Percentage = 10% | 932 | **62%** | 1.20% | 1.27% |
| Externalized Percentage = 25% | 1025 | **69%** | 1.36% | 1.47% |
| Externalized Percentage = 50% | 1239 | **83%** | 1.91% | 1.90% |
| **Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)** | | | | |
| 3-Year Plans | | | | |
| Externalized Percentage = 0% | 623 | **42%** | 1.02% | 0.76% |
| Externalized Percentage = 10% | 1037 | **69%** | 1.65% | 1.64% |
| Externalized Percentage = 25% | 1182 | **79%** | 2.08% | 1.94% |
| Externalized Percentage = 50% | 1253 | **84%** | 2.48% | 2.16% |
| 5-Year Plans | | | | |
| Externalized Percentage = 0% | 811 | **54%** | 1.10% | 1.15% |
| Externalized Percentage = 10% | 1033 | **69%** | 1.42% | 1.42% |
| Externalized Percentage = 25% | 1229 | **82%** | 1.97% | 1.83% |
| Externalized Percentage = 50% | 1280 | **86%** | 2.41% | 2.26% |
| **Rate Option Plans** | | | | |
| 3-Year Plans | | | | |
| No rate option | 623 | **42%** | 1.02% | 0.76% |
| Yearly rate reduction = 1% | 1496 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 1.5% | 1496 | **100%** | 3.93% | 2.71% |
| Yearly rate reduction = 2% | 623 | **42%** | 1.02% | 0.76% |
| Yearly rate reduction = 2.5% | 623 | **42%** | 1.02% | 0.76% |
| 5-Year Plans | | | | |
| No rate option | 811 | **54%** | 1.10% | 1.15% |
| Yearly rate reduction = 1% | 1496 | **100%** | 2.64% | 2.32% |
| Yearly rate reduction = 1.5% | 811 | **54%** | 1.10% | 1.15% |
| Yearly rate reduction = 2% | 811 | **54%** | 1.10% | 1.15% |
| Yearly rate reduction = 2.5% | 811 | **54%** | 1.10% | 1.15% |

*** = measured by the average year-over-year percent decrease in costs**

## Table B3
# Results from the Incentive Power Model

| **50%** initial inefficiency | Net Present Value ($m) of Cost Redutions | Relative Incentive Power | Average Annual Performance Gain* First two rate cycles | Average Annual Performance Gain* Long run |
|---|---|---|---|---|
| **Reference Regulatory Options** | | | | |
| Cost plus | 0 | **0%** | 0.00% | 0.00% |
| 2 Year Cost of Service | 905 | **30%** | 1.33% | 0.75% |
| 3 Year Cost of Service | 1430 | **47%** | 2.36% | 1.05% |
| Full Rate Externalization | 3022 | **100%** | 4.75% | 3.05% |
| **Impact of Plan Term** | | | | |
| Term = 3 years | 1430 | **47%** | 2.36% | 1.05% |
| Term = 5 years | 1778 | **59%** | 2.29% | 1.65% |
| Term = 6 years | 2143 | **71%** | 2.37% | 1.82% |
| Term = 10 years | 2520 | **83%** | 3.29% | 2.42% |
| **Impact of Earnings Sharing Mechanism** | | | | |
| 5-year plans | | | | |
| No Sharing | 1778 | **59%** | 2.29% | 1.65% |
| Company Share = 75% | 1603 | **53%** | 2.06% | 1.36% |
| Company Share = 50% | 1520 | **50%** | 1.96% | 1.22% |
| Company Share = 25% | 1354 | **45%** | 1.75% | 1.02% |
| **Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)** | | | | |
| 3-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 1430 | **47%** | 2.36% | 1.05% |
| Externalized Percentage = 10% | 1551 | **51%** | 2.48% | 1.21% |
| Externalized Percentage = 25% | 2017 | **67%** | 3.17% | 1.90% |
| Externalized Percentage = 50% | 2481 | **82%** | 4.08% | 2.42% |
| 5-Year Plans, Extern | | | | |
| Externalized Percentage = 0% | 1778 | **59%** | 2.29% | 1.65% |
| Externalized Percentage = 10% | 1979 | **65%** | 2.52% | 1.81% |
| Externalized Percentage = 25% | 2279 | **75%** | 2.75% | 2.02% |
| Externalized Percentage = 50% | 2666 | **88%** | 3.68% | 2.60% |
| **Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)** | | | | |
| 3-Year Plans | | | | |
| Externalized Percentage = 0% | 1430 | **47%** | 2.36% | 1.05% |
| Externalized Percentage = 10% | 2202 | **73%** | 3.58% | 2.20% |
| Externalized Percentage = 25% | 2531 | **84%** | 4.30% | 2.61% |
| Externalized Percentage = 50% | 2793 | **92%** | 4.61% | 2.84% |
| 5-Year Plans | | | | |
| Externalized Percentage = 0% | 1778 | **59%** | 2.29% | 1.65% |
| Externalized Percentage = 10% | 2309 | **76%** | 2.81% | 2.04% |
| Externalized Percentage = 25% | 2558 | **85%** | 3.68% | 2.54% |
| Externalized Percentage = 50% | 2880 | **95%** | 4.35% | 2.88% |
| **Rate Option Plans** | | | | |
| 3-Year Plans | | | | |
| No rate option | 1430 | **47%** | 2.36% | 1.05% |
| Yearly rate reduction = 1% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 1.5% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 2% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 2.5% | 3022 | **100%** | 4.75% | 3.05% |
| 5-Year Plans | | | | |
| No rate option | 1778 | **59%** | 2.29% | 1.65% |
| Yearly rate reduction = 1% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 1.5% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 2% | 3022 | **100%** | 4.75% | 3.05% |
| Yearly rate reduction = 2.5% | 1778 | **59%** | 2.29% | 1.65% |

*** = measured by the average year-over-year percent decrease in costs**

Impact of Earnings Sharing

With respect to earnings sharing note first that, in plans of a given duration, the addition of earnings sharing mechanisms reduces cost savings modestly compared to a plan of the same duration with no sharing mechanism. For example, in plans with a five-year term, the addition of an earnings sharing mechanism with a 75% company share reduces average annual performance gains by 24 basis points in the longer run. The lower is the company's share of earnings variances, the lower are cost savings. However, plans of longer duration that *have* an earnings sharing mechanism can deliver more cost savings than shorter rate case cycles and no earnings sharing.

### Implications for the Hydro One SSM Stretch Factor

Let's consider, now, the implications of our incentive power research for the choice of an X factor for Hydro One SSM. Hydro One SSM is proposing a multiyear rate plan with a lengthy eight-year term. In years 6-10 of the plan, a mechanism would share surplus earnings when the ROE exceeds 300 basis points. There is thus little mechanistic earnings sharing envisioned. Many of the utilities in our U.S. productivity sample, meanwhile, operated under formula rate plans.

Table B1 shows that, for utilities operating under MRPs with six- and ten-year terms, average annual performance gains are 1.58% and 2.23% respectively. The 1.91% average of these is a reasonable estimate of average annual performance gains under an eight-year MRP.

Consider, now, that average annual performance gains are 0.00% under cost plus regulation and 0.90% under cost of service regulation with rate cases held every three years. If we assume that half of the productivity growth observations in PSE's 2005-2016 sample period were for utilities operating under formula rates and the rest sought rate cases every three years on average, our incentive power model suggests that the average annual expected performance gain from the plan is 0.50 x (1.91 - .90) = 1.01. Half of this is 0.50. The explicit stretch factor for a utility of average efficiency should thus lie in the [**0.50** – **1.01**] range if the U.S. MFP trend from 2005-16 provides the basis for the base productivity trend in Hydro One SSM's revenue cap index. Moreover, this analysis does not consider the adverse incentive impact of other FERC policies such as ROE premia.

## B.5 PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and statistical research on the performance of gas and electric utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. IRM design and the measurement of utility cost performance are company specialties. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us 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, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. In the last five years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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