Transmission Productivity and Benchmarking Study

15 February 2021

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Executive Summary

Introduction

The Régie de l'énergie has authorized Hydro-Québec Transmission ("HQT") and intervenors in proceeding R-4058-2018 Phase 2 to prepare power transmission productivity and statistical benchmarking studies. These may be used to choose key terms in revenue cap index formulas of HQT's current *mécanisme de réglementation incitative* ("*MRI*") and any succeeding *MRI*. The *Association Québécoise des Consommateurs Industriels d'Électricité* and the *Conseil de l'Industrie Forestière du Québec* retained Pacific Economics Group Research LLC ("PEG") to prepare such studies on behalf of intervenors. This is our report on this work. The report also includes general discussions of principles and methods used in revenue cap index design and statistical benchmarking.

Revenue Cap Index Design

Rate and revenue cap indexes in North American *MRIs* are frequently designed with the aid of statistical research on the input price and productivity trends of utilities. This approach has a solid foundation in cost theory and index logic. Its use in North America has been facilitated by the extensive data that have been available for many years on the operations of numerous gas and electric utilities in the United States ("U.S.").

Productivity indexes are influenced by external business conditions and are not pure measures of cost efficiency. Productivity growth can, for example, be slowed by an increased need for replacement capital expenditures and can accelerate after the expenditure surge. A utility tends to be more capable of brisk productivity growth to the extent that it is currently inefficient.

Several "hot-button" issues have arisen concerning statistical cost research methods in recent *MRI* proceedings. One is the appropriate sample period for these studies. Another is the appropriate capital cost specification. A third is whether the X factor should be adjusted if some capital expenditures are accorded variance account treatment.

Statistical Benchmarking

Statistical benchmarking has been undertaken in many *MRI* proceedings. It is useful for setting initial rates and for choosing the stretch factor terms of revenue cap index formulas. The econometric approach to statistical benchmarking has been favored in Ontario and other jurisdictions in the Englishspeaking world. The stretch factors in *MRIs* of Ontario electric utilities are linked to the outcomes of econometric benchmarking studies.

Transmission Precedents

While *MRIs* are used for power transmission in many countries, few have had revenue cap index formulas designed with the aid of productivity research. The most notable precedent is the revenue cap index recently approved for transmission services of Hydro One Networks. Hydro One proposed and the Ontario Energy Board approved a 0% base productivity trend. In addition to productivity studies, witnesses for Hydro One and Ontario Energy Board staff both prepared econometric benchmarking studies which appraised the Company's recent historical and proposed future cost. The Board chose a 0.30% stretch factor. The *MRI* also provides substantial extra revenue to fund capital expenditures ("capex").

Developing a Research Plan

In October 2020, we submitted a detailed proposal to the Régie to update and upgrade their Ontario power transmission studies. Some of our proposed tasks have not been undertaken due to uncertainty about cost recovery. The benchmarking research proved difficult and PEG appreciates the Régie's deadline extensions. While HQT provided reasonable responses to information requests the process was cumbersome. New information and ideas may yet arise in this proceeding that prompt us to revise some of our results.

The U.S. Power Transmission Industry

The U.S. power transmission industry has experienced substantial change in the last 25 years. The Federal Energy Regulatory Commission tried to develop well-functioning bulk power markets. Utilities were encouraged to join independent system operators ("ISOs") or regional transmission organizations.[1] A growing number of utilities were regulated by formula rate plans that are essentially comprehensive variance accounts. The Energy Policy Act of 2005 sanctioned premium rates of return on equity to encourage transmission investment. Tax incentives and other state and federal policies

[1] Throughout this report we use the term ISOs to refer to regional transmission organizations as well as independent system operators.

encouraged development of wind farms. Growing membership in ISOs complicated the data reported to regulators.

Empirical Research

Productivity

We calculated the trends in the productivity of capital and *charges nettes d'exploitation* ("*CNE*") inputs as well as the multifactor productivity of 51 U.S. electric utilities in the provision of power transmission services.[2] The primary source of data used in the report was FERC Form 1 reports that are in the public domain. In our calculations, multidimensional output indexes were used which tracked trends in transmission line length and peak demand. The weights were drawn from econometric cost elasticity estimates. Capital costs and quantities were measured using a geometric decay specification.

We found that the growth in the multifactor transmission productivity of sampled U.S. utilities averaged a 2.26% annual decline over the most recent fifteen years of the sample period (2005-2019) but only a 0.62% annual decline over the full 24-year 1996-2019 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. The productivity of *CNE* averaged a 1.74% annual decline over the last 15 years and a 0.68% annual decline over the full sample period. The productivity of transmission capital inputs averaged a 2.16% annual decline over the last fifteen years and a 0.46% annual decline over the full sample period. The remarkable productivity decline that began in 2005 reflects special circumstances that we discuss at some length.

Multidimensional Scale Escalators

We encourage the Régie to consider multidimensional output indexes of the kind we have developed as scale escalators in HQT's revenue cap index. The 58% ratcheted peak/42% line length weights used in our *multifactor* productivity research in this proceeding are appropriate for a *comprehensive* revenue cap index. In a revenue cap index applicable only to *CNE* revenue, 53% ratcheted peak/47% line length weights drawn from our *CNE* model are more pertinent.

[2] In this report we use the term *CNE* to reference all costs other than capital costs.

Benchmarking Results

The benchmarking work was complicated by differences in the ways that HQT and sampled US utilities calculate their costs. PEG lodged several rounds of information requests to better understand HQT's cost accounting. Having developed cost calculations that we hope permit "apples to apples" comparisons, we developed econometric models of total transmission cost, transmission capital cost, and *CNE*.[3] There were 46 U.S. utilities in the sample for the econometric research. The total cost and capital cost models had considerably more explanatory power than the *CNE* model.

Total Cost

We compared HQT's total cost thus calculated to the cost projected by our econometric total cost benchmarking model. From 2017-19, the three most recent years for which data are available, HQT's total cost was 67% above the benchmark value on average.[4] This is commensurate with a bottom quartile ranking for the U.S. sample.

Capital Cost

We compared HQT's capital cost to the cost projected by our econometric capital cost benchmarking model. From 2017 to 2019, HQT's capital cost exceeded the benchmarks by 55% on average. This is commensurate with a bottom quartile ranking.

CNE

We compared HQT's CNE to the cost projected by our econometric CNE benchmarking model. From 2017 to 2019, the CNE of HQT was 121% above the benchmark value on average. This is also commensurate with a bottom quartile ranking in the U.S. sample.

Implications for the MRIs

X Factors

The revenue cap index in HQT's current *MRI* applies to its *CNE* revenue. The X factor should then be based on productivity trends in the use of *CNE* inputs (e.g., labor, materials, and services). The options for X include the 1.74% annual decline in the *CNE* productivity of sampled utilities in the last

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[3] A few costs were excluded from these studies, as discussed further in Section 5.

[4] All percentages are stated in logarithmic terms.

fifteen years and the 0.68% decline over the full sample period. The marked decline in *CNE* productivity over the last fifteen years may be due in part to short-term circumstances such as the establishment of new reliability standards. *CNE* productivity growth in the last nine years averaged a 0.57% decline.

The Régie has also evinced interest in the X factor that might be applicable to a future *comprehensive* revenue cap index. Here again choices include the fifteen-year *PMF* decline of 2.26% and a longer-term decline of 0.62%. The Régie should also consider the 0.0% *PMF* growth target that the Ontario Energy Board chose for Hydro One transmission services.

The choice between such numbers depends on other aspects of the *MRI*. A more negative number would help HQT fund more capex without weakening its incentive to contain capex. Capital revenue may in some years exceed HQT's capital cost. This is to be expected if the revenue cap index is to fund occasional capex surges. However, HQT should then have less ability to request extra revenue for these surges.

This report details several provisions for addressing this situation. One is to limit or eliminate eligibility for extra revenue. If supplemental revenue is permitted, provisions like the following merit consideration.

- The X factor could be raised to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

Stretch Factors

The stretch factor term should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the utility's operating efficiency at the start of the *MRI*. It should also depend on how the performance incentives generated by the *MRI* compare to those in the regulatory systems of utilities in productivity studies that are used to set the X factor. Incentive power research by PEG has produced tools that can be useful in comparing the incentive power of regulatory systems.

Our econometric *CNE* benchmarking research suggests that the stretch factor for the current *CNE* revenue cap index should be no less than 0.60%. Our current *total* cost benchmarking results suggest that the stretch factor for any future *comprehensive* revenue cap index would also be no less than 0.60%. These lower bounds are based on the Ontario Energy Board's approach to stretch factor determination. The Régie should consider more aggressive penalties for poor cost performance.

If there is a succeeding *MRI* the Régie may wish to update the benchmarking study in the year in which it is developed. A new study can consider forward test year costs that HQT proposes as well as additional years of historic costs.

The Régie should increase the stretch factor to reflect the unusually weak performance incentives in the U.S. power transmission industry over the sample period. We recommend a stretch factor adder of at least **0.1%** should the Régie base X on productivity results for the full sample period. We recommend an adder of at least **0.3%** if X is based on results for the most recent fifteen years.

1. Introduction

The Régie de l'énergie has been engaged for several years in the development of an *MRI* for power transmission services of HQT. In D-2018-001 (January 2020), the Régie chose the broad outlines of this mechanism. It featured a four-year term and an index formula (*formule d'indexation*) to escalate revenue for its *CNE*.[5] Under the formula, *CNE* revenue grows with inflation and a growth factor (*facteur de croissance*) but is potentially slowed by a productivity factor (X) and a stretch factor (*dividende de client* or *facteur S*).

A provisional X factor of 0.57% was chosen for the formula in D-2019-060. However, the Régie directed HQT to prepare a study of power transmission multifactor productivity [*productivité multifactorielle* ("*PMF*")] in the first three years of its MRI which can be used to reset X in the fourth year of the mechanism.[6] The current *formule d'indexation* also features a 0% *dividende de client* "*en l'absence de données d'études comparatives"*.[7] The *facteur de croissance* is based on gross plant additions related to the "*maintien et amélioration de la qualité du service*" and to the "*croissance des besoins de la clientèle*".[8]

In D-2019-047, the Régie opted for the preparation of two *PMF* studies, one by HQT's chosen expert and another by an expert chosen by intervenors to the proceeding.[9] The Régie made some decisions on the framework for this research in D-2020-028.

- The *PMF* study should be accompanied by a statistical benchmarking study (*étude statistique comparative*) which can be used to set the S factor. This study may use econometric methods and publicly available data on HQT's operations. The experts can request additional data from HQT.[10]

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[5] *Décision* D-2018-001, p. 54, *paragraphe* 213.

[6] *Décision* D-2018-001, p. 32, *paragraphe* 111.

[7] *Décision* D-2019-060, p. 36, *paragraphe* 151.

[8] *Décision* D-2018-001, p. 74, *paragraphe* 301.

[9] *Décision* R-2019-047, p. 149, *paragraphe* 648.

[10] *Décision* D-2020-028, p. 24, *paragraphe* 92.

- The productivity and benchmarking studies should use data on operations of North American power transmitters.[11]
- The sample period for the *PMF* study should be at least 15 years.[12]
- The *PMF* study should be consistent with the approved *MRI.*[13]
- Capital as well as *CNE* efficiency should be considered in both the productivity and benchmarking studies. The best way to model capital cost in such studies should be addressed.[14]
- Details of the calculations should be presented in spreadsheet form.[15]
- The studies should be useful for setting just and reasonable tariffs.[16]

The *PMF* and benchmarking studies that the Régie has authorized are worthwhile for several reasons.

- Due to Québec's outsized reliance on low-cost but remote hydroelectric generation resources, transmission services account for a sizable portion of the charges that customers pay for power. Québec in effect has a transmission-intensive power supply technology.
- The *PMF* studies can provide the basis for X factors in this and any succeeding *MRI*.
- The benchmarking studies can provide the basis for S factors in this and any succeeding *MRI*. This can strengthen HQT's cost containment incentives.
- Whether or not there is a succeeding MRI, a statistical benchmarking study is a useful complement to the more traditional *balisage* studies that HQT has provided in its *dossiers tarifaires* to help the Régie appraise its performance.

[11] *Décision* R-2019-047, p. 22, *paragraphe* 83.

[12] *Décision* D-2020-028, p. 28, *paragraphe* 106.

[13] Ibid, p. 31, *paragraphe* 121.

[14] Ibid, p. 26, *paragraphe* 96.

[15] Ibid, p. 24, *paragraphe* 92.

[16] Ibid, p. 8, *paragraphe* 19.

- Québec's regulatory community can gain expertise about statistical cost research which may prove useful in future *dossiers tarifaires* of Hydro-Québec Distribution and Énergir as well.
- The studies can aid HQT in its cost management.
- The studies may also provide the basis for an alternative growth factor in the *formule d'indexation* for *CNE* revenue and a possible future formula that also applies to capital revenue.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. We have done several power transmission productivity and benchmarking studies, including recent studies for Ontario Energy Board ("OEB") staff which helped the Board choose revenue cap indexes for transmission services of Hydro One Networks and Hydro One Sault Ste. Marie. The *Association Québécoise des Consommateurs Industriels d'Électricité* ("AQCIE") and the *Conseil de l'Industrie Forestière du Québec* ("CIFQ") have asked PEG to prepare a productivity and benchmarking study for this proceeding.

This is our report on this work. Section 2 provides pertinent transmission industry background. Section 3 discusses the use of statistical cost research in benchmarking and revenue cap index design. Section 4 discusses pertinent recent Ontario transmission research and how PEG developed a research plan for this proceeding. PEG's transmission empirical research for AQCIE-CIFQ is detailed in Section 5. We provide in Section 6 our stretch factor and X factor recommendations. Appendix A discusses various methodological topics in the study in more detail, while a brief discussion of PEG's credentials is provided in Appendix B.

2. Transmission Industry Background

2.1. The Power Transmission Business

The main task of a power transmitter is long distance movement of power. Power is received from generating stations and other transmission networks and delivered to load centers and other networks. Transmission is undertaken at high voltages to reduce line losses. Transmitters own and operate substations that reduce the voltage of the power they carry before it is delivered to load centers. Many transmitters also own substations that increase the voltage of power received from generators. The principal assets used in transmission are high-voltage power lines, the towers and underground facilities that carry them, and substations. Other notable transmission assets include circuit breakers, buildings, and land.

2.2. U.S. Power Transmission Industry

To gauge the relevance and interpret the results of statistical cost research using U.S. transmission data it is important to understand some key aspects of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken chiefly by the Federal Energy Regulatory Commission ("FERC"). Transmitter cost and productivity has been greatly affected by FERC regulation and state and federal policies.

Unbundling Transmission Service

Prior to the mid-1990s, U.S. power transmission regulation reflected the vertically-integrated structure of most investor-owned electric utilities in that era. These utilities typically owned the transmission and distribution systems in the areas they served, monopolized retail sales, and obtained most of their electricity from their own power plants. There were fewer bulk power sales and independent power producers using transmission services than there are today.

Since the 1970s, federal policy has increasingly encouraged third party generators and well-functioning bulk power markets. This increased the need for non-discriminatory tariffs for transmission services. In 1996, FERC Order 888 required transmitters to provide services under open access transmission tariffs ("OATTs"). Many details of the resultant functional unbundling of transmission services were addressed in FERC Order 889.

Bulk power markets were also expanded by the initiatives of many American states to restructure retail power markets. In these states, many utility generating assets were sold to IPPs or spun off. Utilities in a few states (e.g., Iowa, Michigan, Ohio, and Wisconsin) sold or spun off transmission assets.

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 facilities to an independent system operator ("ISO"). Transfer of control was voluntary and utilities retained ownership of most of their facilities. Several ISOs were formed between 1996 and 2000.

ISOs have scheduled transmission service, managed transmission facility maintenance, provided system information to potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services are provided under OATTs that recover ISO costs.

In 1999, the FERC pushed for further structural change in markets for transmission services by encouraging formation of regional transmission organizations ("RTOs"). These organizations typically have a larger footprint, serving multiple states while ISOs typically serve a single state. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (now called the Midcontinent ISO) and PJM Interconnection received an RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs still operate in New York, Texas, and California.[17] Many utilities in the southeastern and intermountain states are not ISO or RTO members.[18] Charges of transmission owners who are members of ISOs or RTOs may still be reset in periodic rate cases or formula rate plans.

Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex trended downward in real terms. This was partly due to diminished need. Generation plant additions declined, especially in the 1990s. Another reason for the capex lull was difficulties in siting transmission lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion occurred in some

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

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

areas. This sparked concerns by the FERC and other policymakers that insufficient capex by transmitters could jeopardize the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 ("EPAct") was passed. It affected transmission capex and many other aspects of transmitter operations. The Act gave the FERC authority to establish mandatory transmission reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection ("CIP") standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"), which oversees six regional reliability entities. Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability problems resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators. Concerns about the siting of transmission lines were mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to serve areas of significant transmission congestion.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission capex and participation in an RTO or ISO. The Energy Policy Act required the FERC to adopt rules 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.[19]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. Permissible incentives included the ability for a transmitter to include 100% of construction work in progress in rate base, ROE premiums for some plant additions, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for 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 to 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 alone, the FERC reviewed more than 80 applications for incentives related to proposed transmission projects.

Formula Rates

Rates for transmission services can be set by the FERC in periodic rate cases. However, transmitters can also obtain mechanisms that reset rates annually to reflect the changing cost of their service following expedited reviews. These "formula rates" may rely on a transmitter's 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 involve what are essentially comprehensive cost variance accounts.

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.[20] Economies in regulatory cost have been an important reason for their use. Regulatory cost is a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities as well as dozens of interstate oil pipelines and natural gas pipelines.

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

[20] 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.

Use of formula rates 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 in power transmission included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

In 2004 about 15 of the 56 sampled U.S. transmitters in our econometric sample operated under formula rates. By 2016 fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during these years. Thus, about half of the U.S. transmitters in our sample received approval of formula rate plans during this period.

2.3. Canadian Power Transmission Industry

The services provided by Canadian power transmitters are broadly similar to those of their U.S. counterparts. Power market restructuring has been less pervasive than in the States, and independent system operators have been established only in Alberta and Ontario. However, many utilities trade power with the U.S. and abide by an array of US transmission regulations. One (Manitoba Hydro) is a member of a US RTO, and most are members of regional reliability councils and interconnections such as the Northeast Power Coordinating Council or the Western Interconnection. Transmission rates are regulated at the provincial rather than the federal level.

3. Revenue Cap Index Design

In this section of the report we discuss pertinent principles and methods for designing revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing and statistical benchmarking research in revenue cap index design. We also discuss the capital cost specifications that are used in both kinds of research.

3.1. Basic Indexing Concepts

Input Price and Quantity Indexes

The cost of each input that a company uses is the product of a price and a quantity. The aggregate cost of many inputs is, analogously, the product of a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

Cost = *Input Prices* x *Inputs.* [1]

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) of utilities over time, or *both.* Capital, labor, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of gas and electric utilities. These are capital-intensive businesses, so heavy weights are placed on the capital subindexes.

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[21]

growth Cost = *growth Input Prices* + *growth Inputs.* [2]

Rearranging terms, it follows that input quantity trends can be measured by taking the difference between cost and input price trends.

growth Inputs = *growth Cost* - *growth Input Prices.* [3]

This greatly simplifies input quantity measurement.

[21] This result, which is due to the French economist François Divisia, holds for particular kinds of growth rates.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity (or scale) index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [4]$$

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Productivity indexes can compare productivity levels of different companies in a given year, measure productivity *trends*, or do both. The growth of a productivity trend index can be shown to be the difference between the growth of the output and input quantity indexes.[22]

$$growth\ Productivity = growth\ Outputs - growth\ Inputs. \qquad [5]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes call *total* factor productivity indexes even though they rarely address all inputs. Some indexes measure productivity in the use of a single input class (e.g., labor or capital.) These indexes are sometimes called *partial* factor productivity indexes.

Output Indexes

The output quantity (trend) index of a firm summarizes growth in its outputs or operating scale. If output is multidimensional in character, its trend can be measured by a multidimensional output index. Growth in each output dimension that is itemized is measured by a sub-index, and growth in the summary index is a weighted average of the growth in the sub-indices.

[22] This result holds true for particular kinds of growth rates.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost.*[23] In that event, the index should be constructed from one or more output variables that measure the "workload" that drives cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity."[24] Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[25] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \qquad [6]$$

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[26] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost. Scale economies will typically be lower the slower is output growth.

[23] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of *revenue*.

[24] The cost elasticity of output *i* is the effect on cost of 1% growth in that output.

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

[26] The seminal paper on this topic is Denny, Fuss and Waverman, *Ibid.*

Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be less able to achieve incremental scale economies.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the lower is its current efficiency.

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. This has encouraged the use of productivity indexes to measure operating efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. One example for a power transmitter is the extent to which facilities must be underground. If growth in the urban areas served by a utility requires it to increase transmission system undergrounding, its productivity growth will be slowed.

System age is another business condition that affects productivity. Productivity growth tends to be greater to the extent that the current capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capital expenditures (sometimes called "repex"), cost growth surges and productivity growth can be unusually slow and even decline. Highly depreciated facilities are replaced by facilities that are designed to last for decades and may need to comply with new performance standards. On the other hand, cost growth slackens and productivity growth can accelerate after a period of unusually high capex.

This analysis has some noteworthy implications. One is that productivity indexes are imperfect measures of operating efficiency. Productivity can fall (or rise) for reasons other than deteriorating (improving) efficiency. Our analysis also suggests that productivity growth can differ between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

3.2. Use of Indexing in Revenue Cap Index Design

Revenue Cap Indexes

Cost theory and index logic support the design of revenue cap indexes. Consider first the following basic result of cost theory:

growth Cost = growth Input Prices – growth Productivity^{C} + *growth Outputs*^{C}.[27] [7]

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

growth Allowed Revenue^{Utility} *= growth Input Prices* – (*X* + *S*) + *growth Scale*^{Utility} [7a]

where:

$X = \overline{Productivity^{C}}$. [7b]

S = stretch factor or consumer dividend

Here X, the productivity or X factor, reflects a base growth target ("$\overline{Productivity^{C}}$") which is typically the average trend in the productivity of a regional or national sample of utilities. A consistent cost-based output index is used in the supportive productivity research. A stretch factor is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the *MRI.*

An alternative basis for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[28] It then follows that

growth Cost = growth Input Prices + *growth Outputs*^{C}

- (*growth Outputs*^{C} – *growth Input Quantities*)

= *growth Input Prices – growth Productivity*^{C} + *growth Outputs*^{C} [8]

[27] See Denny, Fuss, and Waverman, *op. cit.*

[28] This result is also due to François Divisia.

Simple vs. Size-Weighted Averages

In calculating industry productivity trends, a choice must be made between simple and size-weighted averages of results for individual utilities. The arguments for size-weighted averages include the following.

- This is a better measure of the *industry* productivity trend.
- To the extent that productivity growth depends on a utility's size, size-weighted results are more pertinent in X factor studies for larger utilities.

Arguments for even-weighted averages include the following.

- Absent evidence that size affects productivity trends, the results for individual utilities are equally important. Econometric cost research places the same weight on all observations.
- Size-weighted averages are sometimes unduly sensitive to results for a few utilities.
- Even if size does affect productivity trends, even-weighted averages are more pertinent in X factor studies for smaller utilities.

PEG typically uses size-weighted (even-weighted) averages in X factor studies applicable to larger (smaller) utilities.

Dealing with Cost Exclusions

General Considerations

It is important to note that relation [8] applies to *subsets* of cost as well as to total cost. Thus, a revenue cap index designed to escalate only *CNE* revenue can reasonably take the form

$$growth\ Revenue^{CNE} = Inflation - (X + S) + \text{growth}\ Scale^{CNE}$$

where

$$X = \overline{Productivity}^{CNE}.$$

Here X is the trend in the productivity of a group of utilities in the management of *CNE* inputs. The scale escalator involves one or more output variables that drive *CNE*.

If the *MRI* provides for certain costs to be addressed by variance accounts, relation [8] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in *MRIs* (e.g., costs of energy, demand-side management, and pension programs) are frequently excluded from the supportive X factor studies.

Capital Cost Exclusions

This reasoning is important when considering how to combine a revenue cap index with *MRI* provisions that furnish extra funding for capex.[29] Many *MRIs* with indexed rate or revenue caps have had provisions for supplemental capital revenue. The rationale is that the index formula cannot by itself provide reasonable compensation for capex surges. Reasons that such surges might be needed include "lumpy" plant additions or a surge in plant that has reached replacement age. Provisions for funding capex often involve variance accounts that effectively exempt capital revenue or a portion thereof from indexing. In Ontario, for example, a "C factor" is sometimes added to a revenue (or price) cap index formula that helps capital revenue grow at a rate that is close to that of forecasted capital cost.

Capital cost variance accounts can require customers to fully compensate the utility for expected capital revenue *shortfalls* when capital cost growth is unusually rapid for reasons beyond its control even though the utility is not required to return any *surplus* capital revenue, in the current or future plan, if capital cost growth is unusually slow for reasons beyond its control.[30] Over multiple plans, the revenue escalation between rate cases would then not guarantee customers the full benefit of the industry's *PMF* trend, even when it is achievable.

A related concern is that most of the capex addressed by capital cost variance accounts (as well as Z factors) would be similar in kind to that incurred by transmitters sampled in past and future productivity studies that are used to calculate the company's X factors.[31] The company can then be compensated twice for the same capex: once via the variance account and then again by low X factors in past, present, and future *MRIs*. Capital variance accounts also weaken performance incentives and can

[29] Notable hearings where this controversy has arisen are discussed below.

[30] Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex will tend to slow future capital cost growth and accelerate productivity growth.

[31] This is also true of Z factors.

encourage companies to exaggerate their capex needs and to bunch their capex in a way that bolsters supplemental revenue.

Given the inherent unfairness to customers of asymmetrically funding only capital revenue shortfalls, the utility's weak incentive to contain capex when afforded variance account treatment, and its incentive to exaggerate capex requirements and bunch capex in ways that bolster extra revenue, regulators and intervenors must be especially vigilant about the utility's capex proposal. The utility may be asked to periodically file a multiyear capex plan. This can raise regulatory cost considerably, and yet the regulator and intervenors will inevitably struggle to effectively challenge the company's capex proposal.

Informed by our research and testimony in several *MRI* proceedings, PEG has detailed a number of possible adjustments to *MRIs* that combine a capital cost variance account and a revenue (or price) cap index. Here are some examples.

- The X factor could be raised mechanistically, in the instant and/or future *MRIs*, to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- The eligibility of capex for supplemental capital revenue can be contained by various means. In the fourth-generation *MRI* currently used by most Ontario power distributors, for instance, a share of otherwise-eligible capex (typically around 5%) is deemed ineligible for supplemental funding between rate cases. Alternatively, eligible capex can be limited to major plant additions.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

<u>Salient Precedents</u>

The "double counting" issue has been debated in several *MRI* proceedings and no consensus has been established. Most regulators have eschewed X factor adjustments and based X factors on *PMF* trends. However, the Hawaii Public Utilities Commission ruled, in a recent *MRI* proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that their major plant additions will be eligible for cost tracking. In British Columbia, *MRIs* for the Fortis companies have tracked the cost of *all* older capital.

Scale Escalators

Formula [7a] raises the issue of the appropriate scale escalator for a revenue cap index. For gas and electric power distributors, the number of customers served is a sensible component of a revenue cap index scale escalator, for several reasons. The customers served variable often has the highest estimated cost elasticity amongst the scale variables studied in econometric research on distributor cost. The number of customers clearly drives costs of connections, meters, and customer services and has a high positive correlation with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote demand side management. This is an argument for excluding these system-use variables from a revenue cap index scale escalator.[32]

In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

Revenue cap indexes do not always include explicit scale escalators. A revenue cap index of general form

$$\textit{growth Revenue}^{\textit{Allowed}} = \textit{growth GDP IPI} - X \qquad [9a]$$

where

$$X = \overline{PMF}^{C}_{Industry} + \textit{Stretch}.$$

is equivalent to the following:

$$\textit{growth Revenue}^{\textit{Allowed}} = \textit{growth GDP IPI} - X + \textit{Stretch}^{\textit{Augmented}} + \text{Expected } \textit{growth Scale}_{\textit{Utility}} \qquad [9b]$$

where

$$X = \overline{PMF}^{C}_{Industry}$$

[32] In choosing a scale escalator for a North American power distributor, it is also pertinent that data on miles of distribution line, another important distribution cost driver, are not readily available for most U.S. power distributors. This bolsters the arguments for using the number of customers as the sole scale variable in an RCI for a U.S. power distributor.

$$Stretch = \textit{Expected growth Scale}_{Utility} + Stretch^{Normal}. \quad [9c]$$

It can be seen that if the *MRI* does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

Inflation Issues

If a macroeconomic inflation index, such as the GDPIPI, is used as the inflation measure in a revenue cap index, Relation [7] can be restated as:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C \\ &\quad + \textit{growth GDPIPI} - \textit{growth GDPIPI} \\ &= \textit{growth GDPIPI} - [\textit{growth Productivity}^C + (\textit{growth GDPIPI} - \textit{growth Input Prices})]. \\ &\quad + \textit{growth Outputs}^C. \end{aligned} \quad [10]$$

Relation [10] shows that cost growth depends on GDPIPI inflation, growth in operating scale and productivity, and on the difference between GDPIPI and utility input price inflation (which is sometimes called the "inflation differential".)

The GDPIPI is the Canadian government's featured index of inflation in the prices of the economy's final goods and services.[33] It can then be shown that the trend in the GDPIPI equals the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{growth GDPIPI} = \textit{growth Input Prices}^{Economy} - \textit{growth PMF}^{Economy}. \quad [11]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{Productivity}^C - \overline{PMF}^{Economy}) + (\overline{\textit{Input Prices}}^{Economy} - \overline{\textit{Input Prices}}^{Industry})]. \quad [12]$$

Here, the first term in parentheses is called the "productivity differential." It is the difference between the productivity trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

[33] Final goods and services include consumer products, government services, and exports.

Relation [12] has been the basis for the design of several approved X factors in *MRI* plans in the United States.[34] Since the *PMF* growth of the U.S. economy has tended to be brisk it has resulted in substantially negative X factors in several American *MRIs* for energy distributors. PMF growth has historically been slower in Canada's economy, and macroeconomic price indexes are less frequently the sole inflation measures in revenue cap indexes.

Stretch Factors

Rationale

In prior direct testimony before the Régie, PEG stated that

> the stretch factor term… should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend. It also depends on the utility's operating efficiency at the start of the MRI.
>
> Initial operating efficiency is often assessed in MRI proceedings by statistical benchmarking studies. The methods used in these studies run the gamut from crude unit cost metrics to sophisticated econometric modelling and data envelopment analysis. In succeeding MRIs, the linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize the utility for a failure to do so.[35]

Incentive Power

In another piece of prior testimony, PEG presented results of some incentive power research that it had previously prepared.[36] Results of this research were published by Lawrence Berkeley National Laboratory.[37] We showed that the incentive power of regulatory systems can be increased by efficiency carryover mechanisms and less frequent rate cases and reduced by earnings sharing

[34] This approach has, for example, been approved in Massachusetts on several occasions. See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, D.P.U. 17-05, and D.P.U. 18-150.

[35] Mark Newton Lowry, "Outstanding Issues in the Design of an MRI for Hydro-Québec Transmission," 9 November 2018, p. 27.

[36] Mark Newton Lowry and Matt Makos, "Incentive Regulation for the Transmission and Distributor Services of Hydro-Québec," Revised HQT Draft 24 February 2017 pp. 136-145.

[37] Mark Newton Lowry, J. Deason, and Matthew Makos, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Lawrence Berkeley National Laboratory, July 2017.

mechanisms. We can then consider how the frequency of rate cases, the prevalence of earnings sharing, and other aspects of ratemaking for sampled utilities compares to the *MRI* of the subject utility.

<u>Precedents</u>

Most power distributors in Ontario operate under an *MRI* called the 4th Generation Incentive Ratemaking Mechanism. The X factor term of the price cap index includes a base productivity growth target and a stretch factor. The base productivity growth target is linked to the *PMF* trends of Ontario distributors. As detailed in the table below, the stretch factor varies with the outcome of an econometric total cost benchmarking study that is updated annually. The best performers get a stretch factor of zero whereas the worst get a stretch factor of 0.6%.[38] No explicit consideration is paid to how the incentive power of the *MRI* differs from that of utilities in the productivity study. The stretch factor the Board chose for the current MRI for transmission services of Hydro One Networks was informed by statistical benchmarking studies, as discussed further below.

Ontario Energy Board Stretch Factor Assignments

Cost Performance in Econometric Model	Assigned Stretch Factor
Actual costs 25% or more below model's prediction	0.00%
Actual costs 10-25% below model's prediction	0.15%
Actual costs within +/-10% of model's prediction	0.30%
Actual costs 10-25% above model's prediction	0.45%
Actual Costs 25% or more above model's prediction	0.60%

3.3. Statistical Benchmarking

What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as:

> A fixed point (esp. a cut or mark in a wall, building, etc.), used by a surveyor as a reference in measuring elevations.[39]

[38] Ontario Energy Board (2013), *EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 21.

[39] "benchmark, n. and adj." OED Online. Oxford University Press.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called key performance indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of HQT and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$Cost\ Performance = Cost^{HQT}/Cost^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Hockey Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Players, for example, are evaluated using multiple performance indicators. The values typically achieved by Hall of Fame members are useful benchmarks. These values reflect a Hall of Fame performance standard.

External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface is not ideal since runner speed is influenced by the slope of the surface. In comparing the costs of utilities, it is similarly recognized that differences in their costs depend in part on differences in the external business conditions they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves (or, in the case of a forward test year, *proposes*) given the business conditions it faces. Benchmarks must, therefore, reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to the business conditions in its service territory. When the focus of benchmarking is total costs, theory reveals that the relevant business conditions include the prices of all inputs and the operating scale of the company. Miscellaneous other business conditions may also drive cost.

Economic theory allows for the existence of multiple output variables in cost functions. The cost of a power distributor depends, for instance, on the number of customers it serves and on the length of its lines.

Benchmarking Methods

In this section, two benchmarking methods commonly used in North American proceedings, econometric and indexing, are discussed.

Econometric Modeling

We noted above that simply comparing the results of a 100-meter sprinter racing uphill to a runner racing on a level course is not ideal for measuring the relative performance of the athletes. Statistics can sharpen our understanding of each runner's performance. For example, a mathematical model could be developed in which time in the 100-meter dash is a function of track conditions like wind speed, racing surface, and gradient. The parameters corresponding to each track condition would quantify their impact on times. The samples of times turned in by runners, under the varying track conditions, could be used to estimate model parameters. The resultant run time model could then be used to predict the typical performance of the runners given the track conditions they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data on the variables.[40] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Economic theory can guide the specification of cost models. As noted above, cost is a function of input prices and output quantities. Multiple output quantity variables may be pertinent. If panel

[40] The estimation of model parameters is sometimes called regression.

data are used in model estimation, the input price indexes in such a study should be able to compare price levels at each point in time as well as price trends over time.

Basic Assumptions Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right-hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. Error terms are a means of modelling the reality that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. The limitations of the model may include mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the underlying functional relationship. It is customary to assume that error terms are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for selecting the business conditions used in cost models. Tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals A cost function fitted with econometric parameter estimates is called an econometric cost model. Such models can be used to predict a company's cost given local values for the business condition variables.[41] These predictions are econometric

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[41] Suppose, for example, that you want to benchmark the cost of a hypothetical transmission utility called Eastern Transmission. You could predict the cost of Eastern Transmission in period *t* using the following model:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot P_{Eastern,t} + \hat{a}_2 \cdot L_{Eastern,t}.$$

Here, $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $P_{Eastern,t}$ is the peak demand that Eastern experiences, and $L_{Eastern,t}$ equals the length of its transmission line. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Cost performance might then be measured using a formula such as:

$$Performance = ln\left(C_{Eastern,t} / \hat{C}_{Eastern,t} \right)$$

benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can be in the past or the future.

Accuracy of Benchmarking Results A cost prediction like that generated in the manner just described is our best single guess of the company's cost given the business conditions that it faces. This is an example of a point prediction. This prediction is apt to differ from the true expectation of cost due, for example, to the exclusion from the model of relevant business conditions.

Statistical theory provides useful guidance regarding the accuracy of such benchmarks. One important result is that an econometric model can yield biased predictions if relevant business condition variables are excluded from the cost model. A model used to benchmark the cost of a power distributor with extensive undergrounding, for example, yields biased cost predictions if it excludes an indicator of this condition. It is therefore desirable to include in the model all cost drivers for which data are available at reasonable cost, are believed to be relevant, and which have plausible and statistically significant parameter estimates.

In addition, statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the data at a given level of confidence. Wider confidence intervals suggesting reduced benchmarking precision are likely to the extent that:

- the model is less successful in explaining the variation in the historical cost data used to estimate the model's parameters;
- the sample size used in model estimation is smaller;
- the number of business condition variables included in the model is larger;
- the business conditions of sample companies are less varied; and
- the business conditions of the subject utility are less similar to those of the typical firm in the sample.

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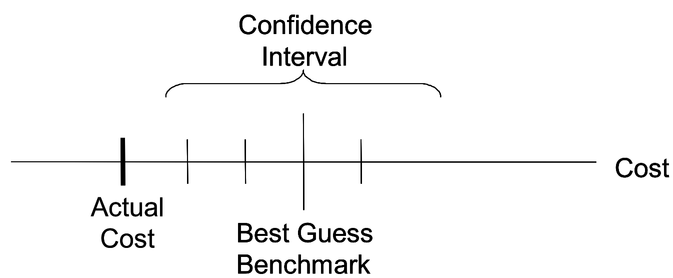
where ln indicates a natural logarithm.

These results have important implications for benchmarking. For example, the results suggest that we can often improve the precision of an econometric benchmarking model by pooling data for sampled companies over multiple years rather than using only a cross-section of data for a single year. In fact, the precision of an econometric benchmarking exercise is actually *enhanced* by using data from companies with diverse operating conditions. For example, to capture the impact of variables that measure the ruralization of a service territory it is useful to have data for utilities that operate under urban as well as rural conditions.

Testing Efficiency Hypotheses Confidence intervals developed from econometric results not only provide us with indications of the accuracy of a benchmarking exercise but also permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average efficiency standard and compute the confidence interval for the benchmark that corresponds to the 90 percent confidence level. It is possible to test the hypothesis that the company has attained the benchmark standard of efficiency. If, for example, the company's actual cost is below the best guess benchmark generated by the model, but nonetheless lies within the confidence interval, the aforementioned hypothesis cannot be rejected. In other words, the company is not a *significantly* superior cost performer.

An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. But there is uncertainty involved in the prediction of benchmarks. These uncertainties are properly reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater the uncertainty is regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered.



Econometric Benchmarking Precedents There are numerous precedents for the use of econometric benchmarking in regulation. The Ontario Energy Board has the most extensive experience in North

America. Most Ontario power distributors operate under *MRIs* that feature price cap indexes. The index formulas in third- and fourth-generation plans have had stretch factors that varied between utilities based on results of econometric cost benchmarking studies commissioned by the Board.[42] The benchmarking in the current (fourth generation) *MRI* uses an econometric model of total cost. The model is used to update the performance scores and stretch factors of distributors annually. Additionally, distributors are required to use this model to benchmark their forward test year cost proposals in rate cases.

Benchmarking is also used in Ontario "Custom" *MRI* proceedings for some of the larger power distributors (e.g., Toronto Hydro-Electric) and the main power transmitter. These utilities frequently benchmark their proposed cost in each year of their proposed *MRIs*. Ontario's benchmarking program effectively serves as an efficiency carryover mechanism since distributors achieving long-term cost savings will have better benchmarking scores, which translates to more rapid revenue growth.

PEG personnel have also provided econometric benchmarking evidence in several other North American proceedings. In Massachusetts, for example, we have used it to support stretch factor proposals in *MRI* proceedings for Bay State Gas, Boston Gas, and NSTAR Gas.[43] We have filed testimony on the cost performance of San Diego Gas & Electric and Southern California Gas on several occasions.[44] In some Colorado PUC proceedings, we used econometric benchmarking to appraise the forward test year cost proposals for the gas and electric services of Public Service of Colorado.[45] In Vermont, PEG benchmarked the cost performance of Central Vermont Public Service in the provision of power

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[42] PEG performed these studies for the OEB.

[43] See Massachusetts D.P.U. proceedings 96-50 and 03-40 (Boston Gas); 05-27 (Bay State Gas); and 19-120 (NSTAR Gas).

[44] See for example, California Public Utilities Commission Application Nos. 02-12-027, 02-12-028 and 06-12-009, and 06-12-010.

[45] See for example, Colorado Public Utilities Commission Proceedings 09AL-299E, 10AL-963G, 17AL-0363G, and 17AL-0649E.

distributor services. This study provided the basis for an article in *The Energy Journal.*[46] Econometric benchmarking has also been used by regulators in Australia and Great Britain.[47]

Indexing

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[48] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

[46] Mark N. Lowry, Lullit Getachew, and David Hovde. *Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors*, THE ENERGY JOURNAL 26 (3), at 75-92 (2005).

[47] See for example, Ofgem, RIIO-ED1 Final determinations for the slow-track electricity distribution companies Business Plan expenditure assessment (2014) and Australian Energy Regulator, Final Decision EvoEnergy Distribution Determination 2019 to 2024 Attachment 6 Operating Expenditure (2019).

[48] Webster's Third New International Dictionary of the English Language Unabridged, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

Unit Cost = Cost/Scale. [13]

Each index compares the value of the metric to the average for a peer group.[49] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. We have noted that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices that utilities face. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\,Input\ Prices}{Scale}. \quad [14]$$

Recollecting that cost is the product of properly-designed input price and quantity indexes

Cost = Input Prices · Input Quantities

it follows that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity \quad [15]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index.

Custom Productivity Growth Benchmarks

We have seen that the cost of an enterprise is a function of input prices, outputs, and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

Cost = f(*Input Prices, Outputs, Other Variables, Time*). [16]

[49] A unit cost index for Eastern Transmission, for instance, would have the general form

$$Unit\ Cost_t^{Eastern} = \frac{(Cost_t^{Eastern}/Cost_t^{Peers})}{(Scale^{Eastern}/\,Scale_t^{Peers})}.$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$

$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \qquad [17]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of model parameters. This model has a double log functional form in which cost and the values of business condition variables are logged. With this form, parameters $\hat{\beta}_1$ to $\hat{\beta}_4$ are also estimates of the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model. This parameter would capture the typical net effect on utility cost trends of technological progress and changes in cost driver variables that are excluded from the model.

Econometric cost research has several uses in the determination of X factors for HQT. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$growth\ Outputs = [\hat{\beta}_1/(\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_1 + [\hat{\beta}_2/(\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_2. \qquad [18]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. An index of this kind can be used in the *PMF* research. It can also serve as the scale escalator of the revenue cap index.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [17], growth in a company's *productivity* can be decomposed as follows. [50]

$$growth\ Productivity = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Outputs + \hat{\beta}_3 \times growth\ Other_1$$

$$+ \hat{\beta}_3 \times growth\ Other_2 - \hat{\beta}_T. \qquad [19]$$

The first term in [19] represents the component of productivity growth that is realized due to economies of scale when output grows. These economies are greater the smaller is the sum of the cost elasticities

[50] Denny, Fuss, and Waverman, *op. cit*.

with respect to output ($\hat{\beta}_1 + \hat{\beta}_2$) and the greater is output index growth. Relation [19] also shows that if a change in the value of a business condition variable like *Other*$_1$ raises cost it also slows *PMF* growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) productivity growth. Formulas like [19] can be generalized to models with additional (or fewer) outputs and other business condition variables.

Econometric cost research and an equation like [19] can be used to identify *PMF* growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [19] can also provide the basis for *PMF* growth benchmarks that are specific to the business conditions of a utility that will be operating under an *MRI*. For example, we can make projections that are specific to HQT during the four likely indexing years (e.g., 2024-2027) of any succeeding *MRI*. These are effectively projections of the *PMF* growth of typical utility managers if faced with HQT's expected business conditions.

For the simple model detailed in equation [19] the productivity growth projection formula would be

$$trend\ \widehat{Productivity}^{C}_{HQT} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \text{ x } trend\ \widehat{Outputs}_{HQT}$$

$$+\ \hat{\beta}_3 \text{x } trend\ \widehat{Other}_{1,HQT} + \hat{\beta}_4 \text{ x } trend\ \widehat{Other}_{2,HQT}) - \hat{\beta}_T. \quad [20]$$

[51]

Here $trend\ \widehat{Productivity}^{C}_{HQT}$ is the projected annual productivity growth trend (average annual growth rate) for HQT during the final four years of its next *MRI*. The variable $trend\ \widehat{Outputs}_{HQT}$ is the expected trend in HQT's output index. $trend\ \widehat{Other}_{l,HQT}$ is the expected trend for HQT in each external business condition that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit.*, were the first to use econometric research and a formula like [19] to decompose *PMF* growth. The method

[51] Here is a more general formula.

$$trend\ Productivity^{C}_{HQT} = \left(1 - \sum_i \hat{\beta}_i\right) \cdot E\left(trend\ \overline{Outputs^{C}_{HQT}}\right) - \sum_l \widehat{\beta}_l \cdot \mathrm{E}\left(trend\ \overline{Others_{l,HQT}}\right) - \widehat{\beta}_T$$

Here $\hat{\beta}_i$ is the econometric parameter estimate for each output variable i while $\hat{\beta}_l$ is the parameter estimate for each other business condition l that is included in the model.

was also used several times in California proceedings.[52] In work for the Ontario Energy Board, PEG used this method in an Ontario gas *MRI* proceeding to project the *PMF* trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[53] These projections were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

Productivity growth projections have several advantages in the design of an X factor for HQT. They are useful for ascertaining the reasonableness of an X factor which is based on more conventional industry cost trend research. Moreover, the projection can pertain to the specific costs that the revenue cap index will address. Despite being customized to HQT's business conditions, the use of these projections would not weaken HQT's cost containment incentives since they reflect only the estimated cost impact of external business conditions.

3.4. Capital Cost Issues

Capital Cost, Prices, and Quantities

Since the technologies of energy transmitters and distributors are capital-intensive, the capital cost specification is important in benchmarking and productivity studies. A discussion of sensible specifications might begin by noting that the annual cost of capital that a utility incurs includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of older assets changes over time, the annual cost may also be net of any capital gains or losses. Annual capital cost is different from the capex or gross plant additions that are added each year to the rate base.

The quantity of capital has several aspects. These include the service flow that the assets provide, their capacity or potential service flow (which may be higher), and the stock of present and future capacity/service flows that are possible. Each of these notions of quantity has a corresponding price. Rental prices are prices for the use of capacity (e.g., the use of a car or hotel room for a day). There are also prices to gain ownership of capital assets (e.g., new and used automobiles).

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[52] See, for example, California Public Utilities Commission A.98-01-014.

[53] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol. 8, Issue 4, December 2009.

Potential and actual service flows from assets may decay as they age and ultimately end. This causes the values of the assets to depreciate. Depreciation is normal, even if the annual capacity/service flow is constant until retirement.

Depreciation and service lives matter, especially in capital-intensive industries. One reason is that opportunity cost accounts for a sizable share of the cost of asset ownership. Depreciation reduces opportunity cost over time and can be an important driver of cost trends. Following a capex surge, for instance, depreciation in the value of a utility's assets may materially slow cost growth. This may be followed later by a period of rapid cost growth when surge assets of decades past need replacement.

The service lives of assets can be an important consideration in the choice between assets. For example, utilities have some ability to extend the service lives of aging assets by increasing *CNE*. This is tantamount to choosing between an old asset with a low opportunity cost of ownership and a new asset that contains a large stock of future service flows but also has a high opportunity cost. Buyers also choose between assets with different service lives in other markets (e.g., those for consumer durables). New assets (e.g., vacuum cleaners) have varied service lives, and there are markets for used assets. In markets of both kinds, asset prices and opportunity costs vary with expected service lives.

Monetary Capital Cost Specifications

<u>The Basic Idea</u>

Monetary approaches to measurement of capital prices and quantities are conventionally used in statistical research on the productivity and cost performance of North American utilities. In these approaches, capital cost ("*CK*") is the product of a consistent capital price index ("*WK*") and capital quantity index ("*XK*").

$$CK = WK \times XK. \qquad [21]$$

The growth rate of capital cost can then be shown to be the sum of the growth rates of these indexes.[54] This decomposition facilitates productivity and econometric cost research.

Construction of capital quantity indexes involves deflation, using asset price indexes, of reported values of gross plant additions. These quantities are then subjected to a standardized decay

[54] This result is specific to certain growth rate measures.

specification.[55] In research on the productivity and cost performances of U.S. energy utilities, Handy Whitman utility construction cost indexes ("HWIs") have traditionally been used as the asset price indexes. Statistics Canada used to compute credible electric utility construction cost indexes but these have been discontinued.

Since some of the plant a utility owns may be 40-60 years old, it is desirable in these calculations to have gross plant addition data for many years into the past. For earlier years, however, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to begin the calculation of a capital quantity index by considering the remaining value of all plant at the end of the limited-data period and then to estimate the quantity of capital that it reflects using data on asset prices in earlier years. This initial year of the capital quantity index is sometimes called the "benchmark year". 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. If this is not done, research on capital and total cost will be less accurate, especially in the early years of the sample period.

Capital Service Flows and Service Prices

A capital good provides a stream of services over some period of time. In rigorous statistical cost research, it is often assumed that the capital quantity index measures the annual flow. A companion capital price index is then chosen that measures the hypothetical price of a unit of capital service. This is sometimes called a "service" price. The design of capital service price indexes should be consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services. This is sometimes called the user cost of capital.

[55] Utilities have various methods for calculating depreciation expenses that they report to regulators and retire their assets at different times. Consequently, when calculating capital quantities using a monetary method, it is desirable to rely on the reporting companies chiefly for the values of their gross plant additions and to use a standardized decay specification for all companies.

Popular Monetary Capital Cost Specifications

Several monetary methods have been established for measuring capital price and quantity trends. A key issue in the choice between these methods is the pattern of decay in the quantity from each year's plant additions. This pattern is sometimes called the age-efficiency profile.

Another issue in the choice between monetary methods is whether plant is valued in historical or replacement (i.e., current) dollars. Historical valuations (sometimes called "book" valuations) are commonly used in North American utility cost accounting. When plant is valued in replacement dollars, utilities experience capital gains if the value of older plant appreciates, and this reduces the cost of capital.

Three monetary methods for calculating capital cost have been used extensively in utility cost benchmarking and X factor research: geometric decay, one-hoss shay, and cost of service. We discuss these methods in turn.

1. Geometric Decay Under this method, the quantity of capital from each group of plant additions to which it is applied declines at a constant rate ("*d*") over time. The capital quantity at the end of each period t ("XK_t") is related to the quantity at the end of the *last* period and the quantity of gross plant additions ("XKA_t") by the following equation:[56]

   $$XK_t = XK_{t-1} \cdot (1-d) + XKA_t \qquad [22a]$$

   $$= XK_{t-1} \cdot (1-d) + \frac{VKA_t}{WKA_t}. \qquad [22b]$$

   The assumed constant rate of depreciation is accelerated relative to straight-line depreciation in the early years of an asset's service life but is less rapid in later years. Note that the quantity of gross plant additions is calculated as the ratio of their value to an asset price index ("WKA").

   The geometric decay method assumes a replacement valuation of plant. Cost is thus computed net of capital gains. The companion capital price is a service price.

[56] Equations of this kind are sometimes called "perpetual inventory equations."

2. One-Hoss-Shay[57] Under the one hoss shay method, the quantity of capital from each group of capital assets to which it is applied is assumed to be constant until the end of its average service life, when it abruptly falls to zero. This decay pattern is typical of an incandescent light bulb. However, in utility cost research this constant-flow assumption is usually applied to the total plant additions each year.

   The quantity of plant at the end of year *t* is the sum of the quantity at the end of the prior year ("XK_{t-1}") plus the quantity of gross plant additions ("XKA_t") less the quantity of plant retirements ("XKR_t"):

$$XK_t = XK_{t-1} + XKA_t - XKR_t \tag{23a}$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \tag{23b}$$

   Since reported utility retirements are valued in historical dollars, the quantity of retirements in year *t* is calculated by dividing the reported value of retirements by the value of the asset price index for the (earlier) year when the retired assets were added.

   Plant is once again valued at replacement cost. The annual cost of capital is then computed net of capital gains. The companion capital price is once again a capital service price.

[57] Wikipedia provides the origin of this term (https://en.wikipedia.org/wiki/One-horse_shay),

> A **one-horse shay** is a light, covered, two-wheeled carriage for two persons, drawn by a single horse. The body is chairlike in shape and has one seat for passengers positioned above the axle which is hung by leather braces from wooden springs connected to the shafts. "One-horse shay" is an American adaptation, originating in Union, Maine, of the French *chaise*. The one-horse shay is colloquially known in the US as a 'one-hoss shay'.
>
> American writer Oliver Wendell Holmes Sr. memorialized the shay in his satirical poem "The Deacon's Masterpiece *or* The Wonderful One-Hoss Shay". In the poem, a fictional deacon crafts the titular wonderful one-hoss shay in such a logical way that it could not break down. The shay is constructed from the very best of materials so that each part is as strong as every other part. In Holmes' humorous, yet "logical", twist, the shay endures for a hundred years (amazingly to the precise moment of the 100th anniversary of the Lisbon earthquake shock) then it "went to pieces all at once, and nothing first, — just as bubbles do when they burst". It was built in such a "logical way" that it ran for exactly one hundred years to the day.
>
> In economics, the term "one-hoss shay" is used, following the scenario in Holmes' poem, to describe a model of depreciation, in which a durable product delivers the same services throughout its lifetime before failing with zero scrap value. A chair is a common example of such a product.

3. Cost of Service ("COS"). The geometric decay and one hoss shay approaches for calculating capital cost use assumptions that differ from those used to calculate capital cost in traditional cost of service ratemaking.[58] With both approaches, we have seen that the trend in capital cost is a simulation of the trend in cost incurred for purchasing capital services in a competitive rental market. The derivation of a revenue cap index using index logic does not require a service price/service flow treatment of capital cost and can in principle use more familiar capital cost accounting provided that capital cost can still be decomposed into price and quantity indexes.

   The alternative COS approach to measuring capital cost achieves this decomposition and uses a simplified version of COS accounting. Plant is valued in historical dollars and straight-line depreciation of asset values is applied. Capital cost is not intended to simulate the cost of purchasing capital services in a competitive rental market, and the capital price is not a simulation of a capital service price. The formulae are complicated, however, making them more difficult to code and review.

Two other methods for calculating capital cost also warrant discussion – hyperbolic decay and the Kahn method:

4. Hyperbolic Decay Hyperbolic decay has rarely if ever been used in North American X factor or utility benchmarking studies but merits consideration in these applications. Under this approach the quantity of capital from groups of assets to which it is applied is assumed to decline at a rate that may vary as they age. This is appealing because the service flow from many utility assets seems to decline more markedly as they age.

   Like one-hoss shay and geometric decay, a hyperbolic decay specification typically entails a replacement valuation of plant. The annual cost of capital is therefore computed net of capital gains. The capital price is a service price which reflects these assumptions.

5. Kahn Method. An X factor can also be calculated using the simpler Kahn Method. This method was developed by Alfred Kahn, the distinguished regulatory economist who was a professor at Cornell University. It has been used by the FERC to set the X factors in *MRIs* for interstate oil pipelines. PEG has upgraded the method that Dr. Kahn used to better approximate cost of service capital cost

[58] The OHS assumptions are more markedly different.

accounting. The PEG approach was recently embraced by the Régie in choosing the provisional X factor in the *formule d'indexation* for the *CNE* revenue of HQT. PEG used this method in recent Massachusetts and Hawaii *MRI* proceedings.[59]

In this proceeding, the Kahn Method might involve calculating trends in the cost of base rate inputs of a sample of U.S. power transmitters using an approximation to traditional capital cost accounting and then solve for the value of X which would cause the trend in transmitter cost to equal the trend in a revenue cap index with a formula like:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Outputs}^{C}. \quad [24]$$

The X factor resulting from such a calculation reflects the inflation differential that we discussed in Section 3.2 above as well as the productivity trends of sampled utilities. This is a problem in an application to HQT since the inflation differential for a U.S. utility may differ considerably from that which is pertinent in Canada. Meanwhile, we don't have the data for multiple utilities that would permit us to compute a Kahn X specific to Canada.

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been debated in several *MRI* proceedings.[60] Based on PEG's experience in debates of this nature we believe that the following considerations are particularly relevant.

The Goal of X Factor Research is to Find a Just and Reasonable Means to Adjust Rates Between Rate Cases.

Statistical cost research has many uses, and the best capital cost specification for one application may not be best for another. One use of such research is to measure a utility's operating efficiency. Another use is to determine the X factor in a rate or revenue cap index.

Revenue cap indexes used in utility *MRIs* are intended to adjust allowed revenue between general rate cases that employ a cost-of-service approach to capital cost measurement. In North

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[59] See Massachusetts DPU 18-150, Exhibits. AG-MNL, pp. 15-16 and AG-MNL-2, pp. 39-40, and Hawaii PUC 2018-0088, Initial Comprehensive Proposal of the Hawaiian Electric Companies, Exhibit A, *Designing Revenue Adjustment Indexes for Hawaiian Electric Companies*, August 14, 2019, pp. 19-20.

[60] See, for example, Exhibit M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

America, the calculation of capital cost in rate cases typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of the assets that sampled utilities add in a given year shrinks over time as depreciation reduces their net plant value and the return on rate base. Capital cost can rise rapidly in a period of high repex.

When a macroeconomic inflation measure like the GDP-IPI is the revenue (or price) cap index inflation measure, the input price trend of utilities becomes an issue as well as the productivity trend in X factor determination. The capital price index then becomes a criterion in the choice of the capital cost specification as well as the productivity index since an input price differential must be chosen. Some capital cost specifications have volatile capital prices. X factor witnesses often try to downplay this volatility, but more recently the X factor witness for power distributors National Grid (D.P.U. 18-150) and Eversource (D.P.U. 17-05) has touted the appropriateness of a large negative input price differential that benefitted its client, and the Massachusetts regulator embraced their analysis. Large input price differentials do not always favor utilities. In a proceeding to approve a price cap index for Central Maine Power, a witness for consumer interests asked for a large *positive* input price differential.[61]

<u>One Hoss Shay Pros and Cons</u>

One Hoss Shay Advantages The one hoss shay specification is sometimes argued to better fit the service flows of individual utility assets than geometric decay. The argument is that many assets, once installed, provide a fairly constant service flow for many years. One hoss shay has for this reason been used in some productivity studies filed in proceedings to determine X factors.

Another advantage of one hoss shay is that the data are unavailable in some applications to accurately calculate capital quantities using monetary methods. In these applications, the assumption of a one hoss shay service flow legitimizes using available data on capacity (e.g., line miles) as a capital quantity metric.[62]

One Hoss Shay Disadvantages Other considerations suggest that the one hoss shay specification is disadvantageous. Notable problems include the following.

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[61] Maine PUC Docket 1999-00666

[62] However, capacity data are then unavailable as measures of output.

- Individual utility assets frequently do not exhibit a constant service flow until their retirement. For example, many assets tend to have diminished reliability, require more maintenance and safety inspections, and/or do more environmental damage as they age. For example, HQT stated in response to an information request from PEG that

  > **Dans le dossier tarifaire 2013 et 2014**, **le Transporteur a expliqué que le vieillissement de son parc d'actifs entraîne des pressions à la hausse sur ses charges. D'une part, il a précisé que les activités de maintenance corrective ou préventive requises sont par nature plus significatives et augmentent ainsi les coûts de maintenance. D'autre part, le Transporteur a indiqué qu'il procède à des interventions ciblées et de réhabilitation ayant pour but de diminuer le risque de défaillance majeure d'équipements et d'éviter d'importants investissements pour les remplacer. Il a également expliqué que la forte sollicitation du réseau entraîne également une pression accrue sur le coût des interventions.**
  >
  > **Dans le dossier tarifaire 2016, le Transporteur a indiqué que les analyses sur ses travaux de maintenance passées démontrent que plus l'âge d'un actif augmente, plus le risque de bris et de défaillance augmente.**
  >
  > **Finalement, dans le dossier tarifaire 2017, le Transporteur a démontré que l`âge moyen du parc entraîne des effets importants sur la maintenance en précisant que l'effort de maintenance augmente de manière significative une fois passé le 50 % de la durée de vie utile d'un équipement.**[63]

- In productivity studies, capital quantity trends are not calculated for *individual* assets. Instead, they are typically calculated from data on the total value of *all* of the additions to (and, in the case of one hoss shay, retirements of) the various kinds of assets that a utility uses. Even if each individual asset did have a constant service flow, the flow from total plant additions could be poorly approximated by one-hoss shay[64] for several reasons.

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[63] B-0265 (HQT-16, Document 1), p. 9.

[64] Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development stated in the Executive Summary that:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a

a. Different kinds of assets can have markedly different service lives.

b. Assets of the same kind have varied service lives. Identical light bulbs installed by Québec homeowners on June 1 in a given year, for instance, will burn out at different times. In power transmission and distribution, the service lives of assets vary due to casualty losses (e.g., due to severe storms).

c. Individual assets sometimes have components with different service lives. The fixtures on a transmission tower, for example, might need replacement before the tower itself.

- The value of assets with one hoss shay service flows depreciate as they age because of diminution in their expected future service flows. However, the simple one hoss shay approach abstracts from asset value depreciation since the service flow from the asset is assumed constant and the price of capital services is one that is commensurate with a competitive rental market. This matters for several reasons.
    - Depreciation reduces the opportunity cost of owning assets, and this is a material consideration when benchmarking utility cost. Using a simple one hoss shay approach in a benchmarking study, a utility's effort to delay replacement of assets will not be recognized. On the other hand, a capital cost specification that is more sensitive to age complicates modelling by raising the need for an appropriate age variable.
    - Depreciation can materially affect utility cost trends in the short and medium term, and its effect merits consideration in X factor selection. For example, we might want X to be less (more) positive if the subject utility and utility industry are both in a period of high (low) capex.
    - Depreciation is another reason why the quantity of a group of assets declines as they age. For example, as the asset ages, the utility obtains a constant service flow from a

single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes.

OECD, *Measuring Capital OECD Manual 2009*, 2nd ed., at 12.

33-year-old asset one year and from a cheaper 34-year-old asset the next. This is arguably a quantity decline.

- One hoss shay is more difficult to implement accurately than other capital cost specifications. To understand this point, consider first that all monetary methods require deflation of gross plant *additions*. These calculations are facilitated by the fact that the years in which given additions are made are known exactly, so that it is easy to choose the matching value of the asset price deflator. The challenge with one hoss shay is that it also requires deflation of plant *retirements*, and the vintages of reported retirements are not readily available for a large number of utilities. One hoss shay practitioners commonly address this challenge by deflating the value of retirements by the value of an asset price index for a year in the past which reflects the assumed average service life of the assets. Deflations by this means can be well off the mark.
- One hoss shay has given rise to methodological controversies in *MRI* proceedings. The biggest controversy has concerned the average service life of assets. PEG's empirical research suggests that productivity results using one hoss shay are quite sensitive to the average service life assumption. Since the average service life is used to match a value for the asset price index to the retirements value, and retirements reduce the capital quantity, a higher average service life tends to slow measured capital quantity growth and thereby accelerate *PMF* growth. The average service life can then be a "fudge factor" in an X factor study.

  To better understand why this is important, consider that the recent popularity of one hoss shay in X factor studies was triggered by its use in the first Alberta generic *MRI* proceeding (2010-2012). The Alberta Utilities Commission hired National Economic Research Associates ("NERA") to study U.S. power distribution productivity. The sample period for their study (1975-2009) was unusually long. NERA found that the *PMF* of sampled U.S. distributors rose briskly in the first half of their full sample period and fell briskly in the second half. In this and the Alberta's second generic *MRI* proceeding utility consultants (e.g., the Brattle Group and Christensen Associates) largely embraced NERA's methods but argued that the X factor should, contrary to NERA's recommendation, be based on results for a more recent sample period, when *PMF* was declining.

Now, NERA used a constant average service life in its capital quantity calculations whereas the actual average service life of U.S. power distributors rose in the second half of the sample period and materially exceeded the NERA assumption. While Brattle and Christensen defended one hoss shay using the constant service flow argument, PEG as witness for an Alberta consumer group argued that their finding of negative productivity growth was due in part to an average service life assumption that was inappropriate for the truncated sample period they advocated. With a more realistic service life assumption, PEG found that *PMF* growth was considerably higher, and similar to that produced using geometric decay.

With one hoss shay as the new *cri de guerre* of utility productivity witnesses, London Economics International ("LEI" another one hoss shay proponent) and Christensen Associates won contracts to provide productivity research and testimony for Massachusetts energy distributors and used one hoss shay capital cost specifications. Due in part to data limitations, the average service lives that they used in two studies for gas distributors were appropriate for their sample periods rather than too low. Both studies found *positive PMF* growth trends for the full U.S. sample. [65]

- For various reasons, one hoss shay studies sometimes produce negative capital quantities. In the second generic *MRI* proceeding in Alberta, for instance, Christensen reported in response to an information request that if they raised the average service life to a level more similar to that actually reported by utilities during their chosen sample period it produced negative capital quantities for some utilities. Christensen and LEI encountered the same problem when they tried to use Handy Whitman gas utility construction cost indexes as asset price deflators in their recent Massachusetts studies. Both consultants instead used a producer price index to deflate asset values.

[65] Both witnesses argued in Massachusetts that the X factors for their gas distribution clients should be based on the *PMF* trends of the subset of sampled distributors serving northeastern states, where *PMF* growth was slower. In Alberta, where a regional sample produced more *rapid* productivity growth, Christensen Associates (and Brattle) favored a U.S. sample.

Geometric Decay Pros and Cons

Geometric Decay Advantages

- Geometric decay takes some account of the depreciation and decline in capital quantities that result over time from a cohort of diverse assets.
- In an X factor study, geometric decay is therefore more sensitive to any capex cycle that an industry might display. It is also more sensitive to system age in a benchmarking study. A remarkable effort by a utility to extend asset life can be recognized.
- The price and quantity formulas are simple and intuitively appealing.
- Calculation of retirement quantities is not required.
- Results are less sensitive to the average service life assumption.

Geometric Decay Disadvantages

- The assumption of constant decay means that initial decay is considerably greater than that which actually occurs. Some have argued that one hoss shay is a closer approximation to actual service flows than geometric decay even if it is imperfect.
- Some practitioners seek TFP trends that are relatively insensitive to capex surges.

Popularity of Alternative Capital Cost Specifications

Here is some evidence on the popularity of alternative capital cost specifications in productivity research.

- The U.S. Bureau of Labor Statistics, Australian Bureau of Statistics, and Statistics New Zealand use hyperbolic decay in their *PMF* studies of the economy and important sectors thereof.[66] Statistics Canada uses geometric decay in such studies.

[66] See for example, Bureau of Labor Statistics, Multifactor Productivity, *Technical Information About the BLS Multifactor Productivity Measures,* at 3 (September 26, 2007).

- Table 1 reports capital cost specifications used in North American energy utility productivity studies. It shows that geometric decay was by far the most common method used in these studies. In Ontario, for example, geometric decay is routinely used today in most productivity and benchmarking studies that are filed by OEB staff and utility witnesses. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used geometric decay.[67]

  It is also notable that Christensen Associates used geometric decay in virtually all of their numerous studies of telecommunications and cable television productivity, as well as in energy distribution productivity studies that they prepared before their Alberta and Massachusetts engagements. Concentric Energy Advisors used the Kahn method in testimony for HQT and geometric decay in a gas utility productivity study for Enbridge Gas Distribution in Ontario.[68] Table 1 also shows that the cost of service and Kahn methods have both been used more frequently than one hoss shay. However, there has been an uptick in recent years in (utility-funded) studies using one hoss shay. In addition to the two Massachusetts *gas* distributor studies noted above, there have been two Massachusetts *power* distributor studies. Furthermore, the Massachusetts Department of Public Utilities ("DPU") has embraced the one hoss shay specification explicitly. PEG used one hoss shay in its recent Massachusetts gas distributor productivity study due in part to the DPU's stance and in part due to budgetary limitations.

<u>Conclusions</u>

The cost-of-service capital cost specification has many advantages in X factor studies. However, the math is complicated, and the assumption of historical plant valuations is not ideal for a benchmarking study. Hyperbolic decay may make the most sense for benchmarking, but its use in utility applications has not been funded. Geometric decay is a serviceable alternative for both X factor research and benchmarking, especially in Canada where inflation differentials are not a major issue.

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[67] Mark N. Lowry, Jeff Deason, and Matt Makos (2017), *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, LAWRENCE BERKELEY NATIONAL LABORATORY, at B. 19-20 (July 2017).

[68] James Coyne, James Simpson, and Melissa Bartos, *Incentive Ratemaking Report* (prepared for Enbridge Gas Distribution), OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

Table 1

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence[69]

Power Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1994	Maine	PEG personnel[1]	Utility	Northeast Bundled Power Service	Geometric Decay
1995	New York	PEG personnel[1]	Utility	US Bundled Power Service	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Power Distributors	Geometric Decay
1999	Hawaii	PEG	Utility	US Bundled Power Service	Geometric Decay
1999	Maine	NERA	Utility	Northeast Power Distributors	One Hoss Shay
2000	Alberta	NERA	Utility	Western Power Distributors	One Hoss Shay
2001	Maine	PEG	Utility	Northeast Power Distributors	Geometric Decay
2002	California	PEG	Utility	US Power Distributors	Geometric Decay
2004	California	PEG	Utility	US Power Distributors	Geometric Decay
2005	Massachusetts	PEG	Utility	Northeast Power Distributors	Geometric Decay
2006	California	PEG	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Bundled Power Service	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Generation	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Transmission	Geometric Decay
2007	Maine	PEG	Utility	Northeast Power Distributors	Cost of Service
2008	Maine	Christensen Associates	Regulator	Northeast Power Distributors	Geometric Decay
2008	Vermont	PEG	Utility	US Power Distributors	Cost of Service
2008	Ontario	PEG	Commission	Ontario Power Distributors	Cost of Service
2008	Ontario	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2010	California	PEG	Utility	US Power Distributors	Geometric Decay
2010	Alberta	NERA	Commission	US Power Distributors	One Hoss Shay
2011	District of Columbia	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	New Jersey	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Alberta	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2012	Delaware	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Power Distributors	Kahn Variant
2013	British Columbia	PEG	Consumer Advocate	US Power Distributors	Cost of Service
2013	Massachusetts	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	Massachusetts	Acadian Consulting	Consumer Advocate	Northeast Power Distributors	Cost of Service
2013	Maine	PEG	CMP	Northeast Power Distributors	Cost of Service
2013	Ontario	PEG	Regulator	Ontario Power Distributors	Geometric Decay
2015	Alberta	Brattle Group	Utility	US Power Distributors	One Hoss Shay
2015	Alberta	PEG	Consumer Advocate	US Power Distributors	Geometric Decay
2015	Alberta	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2016	Ontario	LEI	Utility	US Hydro-electric Generation	One Hoss Shay (Physical Asset)
2016	Ontario	PEG	Regulator	US Hydro-electric Generation	Geometric Decay
2017	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2018	Massachusetts	Acadian Consulting	Consumer Advocate	US Power Distributors	Geometric Decay
2017	US	PEG	Government	US Power Distributors	Geometric Decay
2017	Ontario	NERA	Utility	US Power Distribution	One Hoss Shay
2018	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2019	Massachusetts	PEG	Attorney General	US Power Distributors	Geometric Decay and Kahn Variant
2018	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Hawaii	PEG	Utility	US Bundled Power Service	Kahn Variant
2020	Hawaii	Binz	Environmentalist	US Bundled Power Service	Kahn Variant

[69] As filed in Massachusetts D.P.U. 19-120, Exhibit AG-MNL-Surrebuttal, filed May 8, 2020, p. 9.

Table 1 (continued)

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Gas Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1995	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1996	Massachusetts	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	British Columbia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	Georgia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1999	Ontario	Christensen Associates	Utility	Company-specific	Geometric Decay
2002	California	PEG	Utility	US Gas Utilities	Geometric Decay
2003	Massachusetts	PEG	Utility	Northeast Gas Distributors	Geometric Decay
2004	California	PEG	Utility	US Gas Utilities	Geometric Decay
2006	California	PEG	Utility	US Gas Utilities	Geometric Decay
2007	Ontario	PEG	Regulator	US Gas Utilities	Cost of Service & Geometric Decay
2010	California	PEG	Utility	US Gas Utilities	Geometric Decay
2011	Quebec	PEG	Utility and Consumer Adv	US Gas Utilities	Cost of Service
2011	Ontario	PEG	Regulator	Gas Utilities	Cost of Service
2012	Quebec	PEG	Utility	US Gas Utilities	Cost of Service
2013	British Columbia	PEG	Consumer Advocate	US Gas Utilities	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Gas Utilities	Kahn Variant
2013	Ontario	Concentric Energy Advisors	Utility	US Gas Utilities	Geometric Decay
2018	Ontario	PEG	Regulator	US Gas Utilities	Geometric Decay
2019	Massachusetts	LEI	Utility	US Gas Distributors	One Hoss Shay
2020	Massachusetts	PEG	Attorney General	US Gas Distributors	One Hoss Shay

Oil Pipeline Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1993	US	Klick	Utility	US Oil Pipelines	Kahn
1993	US	NERA	Consumers	US Oil Pipelines	Kahn
2000	US	FERC Staff	Regulator	US Oil Pipelines	Kahn
2000	US	NERA	Utility	US Oil Pipelines	Kahn
2000	US	Shippers	Consumers	US Oil Pipelines	Kahn
2005	US	Innovation and Information	Consumers	US Oil Pipelines	Kahn
2005	US	NERA	Utility	US Oil Pipelines	Kahn
2010	US	NERA	Utility	US Oil Pipelines	Kahn
2010	US	Brattle	Consumers	US Oil Pipelines	Kahn
2015	US	FERC Staff	Regulator	US Oil Pipelines	Kahn
2015	US	NERA	Utility	US Oil Pipelines	Kahn
2015	US	Brattle	Consumers	US Oil Pipelines	Kahn

[1] Economists now affiliated with PEG prepared these studies when they worked for Christensen Associates.

4. Developing a Research Plan

Having established a foundation for understanding key methodological issues in X factor and benchmarking research, we discuss in this section how we developed a research plan for this project. We begin by discussing the power transmission productivity and benchmarking studies submitted in two recent Ontario Energy Board proceedings. These studies are especially germane because they were undertaken recently, in the jurisdiction of an experienced *MRI* practitioner, to determine the base productivity trend and stretch factors for power transmitters. We then explain our proposal to upgrade this research and how our research plan evolved in response to Régie commentary and HQT's responses to information requests.

4.1. The Hydro One Proceedings

The first of these proceedings (EB-2018-0218) considered an *MRI* for Hydro One Sault Ste. Marie, a small transmission subsidiary of Toronto-based Hydro One Networks which serves a region on the eastern shore of Lake Superior. The second proceeding (EB-2019-0082) concerned an *MRI* for Hydro One's main transmission business. In both proceedings, Hydro One proposed a revenue cap index that would apply to capital cost as well as *CNE*. However, a C factor term in the formula would correct for any difference between forecasted capital cost and the capital revenue that would otherwise be provided by the revenue cap index. Hydro One proposed a 0% base productivity trend and stretch factor and no growth factor.[70]

To support these proposals, Hydro One presented in evidence an econometric total transmission cost benchmarking study and calculations of transmission productivity trends of Hydro One and a large sample of U.S. electric utilities.[71] Both studies were prepared by Power Systems Engineering ("PSE"), a

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[70] In June 2019, the Board in Decision and Order EB-2018-0218 chose a 0% productivity factor and a 0.3% stretch factor for Hydro One Sault Ste. Marie. In April 2020, the Board in Decision and Order EB-2019-0082 chose a 0% base productivity trend and a 0.3% stretch factor for transmission services of Hydro One Networks.

[71] Power Systems Engineering, *Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons*, 24 January 2019, filed as Exhibit A-4-1 Attachment 1 in EB-2019-0082 and Power Systems Engineering, *Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons*, 23 May, 2018, filed as Exhibit D-1-1 Attachment 1 in EB-2018-0218.

consulting firm based in Madison, Wisconsin.[72] Board staff retained PEG to appraise PSE's work and prepare independent transmission productivity and benchmarking studies.[73]

Several aspects of these studies merit note.

- Both consultants developed econometric cost models and used them to benchmark Hydro One's historical cost over the 2004-2016 period and its forecasted cost over the 2017-2022 period.
- Both consultants also used multidimensional output indexes in their productivity calculations. These indexes featured two scale variables: transmission line km and ratcheted peak demand. Each consultant used weights for these subindexes which were drawn from their econometric cost research. Econometric cost research thus played a dual role in the Ontario studies.
- PSE used data from 48 utilities (47 U.S. utilities plus Hydro One) in its productivity study and from 57 utilities (56 U.S. utilities plus Hydro One) in its econometric cost benchmarking study.[74] The sizes of these samples were reduced by miscellaneous data problems that included mergers and acquisitions, spinoffs of transmission operations, and the non-availability of some transmission system and output data.
- The companies in PEG's samples were similar to those in PSE's samples because PEG, with a limited budget, wished to use some of the business condition variables that PSE had developed for its econometric model. These variables included indexes of the relative price levels of labor and capital in the service territories of sampled utilities.[75] These price level indexes were for a more recent year than those that PEG had previously calculated, and values had been calculated

[72] The principal investigator of PSE's studies for Hydro One was a former employee of PEG.

[73] Mark Newton Lowry, *Incentive Regulation for Hydro One Transmission*, EB-2019-0082 Exhibit M1, September 2019 p. 36.

[74] The econometric sample was larger because a "balanced" panel (i.e., a sample with the same number of observations for each company) is not required.

[75] Due to the substantial work involved in calculating price level indexes for use in econometric cost studies, they are typically calculated only occasionally for X factor and benchmarking studies. Input prices in other years are obtained by trending these index levels.

for Hydro One as well as the sampled U.S. utilities.[76] PSE had also developed a construction standards index that measures how the minimum requirements for the strength of transmission structures varies with weather in various geographic regions.

- The sample period for PSE's productivity and benchmarking studies was 2004 to 2016. PEG instead used the twenty-one-year period from 1996 to 2016. Productivity results proved to be quite sensitive to the choice of the sample period. For example, PEG reported that *PMF* tended to rise briskly from 1996 to 2006 but to fall briskly from 2008 to 2016. *PMF* averaged a -1.02% average annual decline over the last 15 years of PEG's sample period (2002-2016). Over its full 21-year sample period, PEG found that *PMF* growth averaged only a 0.25% annual decline.
- An informal review identified several possible reasons for the recent decline in U.S. transmission *PMF* growth. These included 1) higher capex in order to access remote renewable resources, increase capacity to serve growing economies (e.g., in the sunbelt states), eliminate load "pockets" in bulk power markets, and replace aging facilities 2) new service quality standards, 3) the Energy Policy Act of 2005 which, as noted in Section 2.2, authorized the FERC to provide special incentives for transmission capex, and 4) increased use by the FERC of formula rate plans for power transmission, which weakened utility cost containment incentives.
- Controversy emerged over the appropriate sample period for establishing the base *PMF* trend. Hydro One's consultant proposed to use the thirteen-year 2004-2016 period when *PMF* averaged a -1.45% decline. PSE reported a -0.18% *PMF* trend for Hydro One over this same period.
- Another area of controversy was whether the *PMF* trend of the industry was pertinent for setting X considering that the Company was asking for supplemental capital revenue.
- A third area of controversy was the appropriate econometric method for estimating cost model parameters.
- Both consultants employed geometric decay capital cost specifications in their studies.

[76] PSE had calculated a labor price level index for the year 2010 and a capital price level index for the year 2011. PEG at that time had labor and capital price level indexes for 2008. All of these indexes are now quite dated.

- PSE purchased rights to most of the transmission operating data that it used in these studies from SNL Financial, a commercial vendor that is a unit of S&P Global Market Intelligence. Subscriptions to SNL data are costly and must typically be renewed annually. PEG used data that it had gathered from the FERC and other publicly-available sources.

4.2. Implications for this Proceeding

The recent Ontario studies illuminate the path forward for the transmission productivity and benchmarking studies in this proceeding. It is clearly feasible to undertake productivity and econometric total cost benchmarking studies for power transmission utilities which are like the studies used in other North American *MRI* proceedings. Data on transmission operations are available for a sizable sample of U.S. electric utilities and also for Hydro One Networks, a sensible Canadian peer for HQT.

However, these studies are now dated. Moreover, PSE had no prior experience preparing transmission productivity and benchmarking studies, and the budgets provided by the Ontario Energy Board for PEG's studies were limited.[77] The Ontario studies can thus be updated and upgraded to increase their quality and relevance to the situation of HQT.

- The biggest single task is to benchmark the cost of HQT. Benchmarking HQT's cost using data from U.S. utilities (and possibly also Hydro One) is quite challenging for reasons that include different approaches to cost accounting and the need to compare U.S. and Québec input prices.
- Another large task is to develop cost benchmarking models for *CNE* and capital cost.
- U.S. transmission operating data are now available for three additional years (2017-2019). Adding these data to the sample is desirable to sharpen our understanding of recent trends and to make econometric model parameter estimates more precise and appropriate for current conditions.
- There is more to learn about the causes of recent transmission productivity declines. This is important given the sensitivity of transmission productivity trends to the sample period. HQT

[77] At Board staff's request, PEG devoted a lot of its effort in the second Hydro One transmission *MRI* proceeding to considering alternative mechanisms for providing extra capital revenue. Upgrades to the empirical studies were discouraged.

may not be experiencing cost pressures or cost containment incentives like those that U.S. transmission utilities experienced in the last 10-15 years. Ideally, we would like to know the productivity growth that should be expected of transmitters facing cost pressures like those that HQT is expected to face in the near future. Econometric research can quantify the relative importance of various productivity growth drivers, and the results can be used to fashion custom productivity growth benchmarks for HQT.

- The productivity and econometric benchmarking methods can be upgraded in various ways. For example, new business condition variables merit consideration in the econometric cost benchmarking model.
- The productivity and benchmarking methods that we used in Ontario have to be revised to reflect certain limitations of HQT's data.
- Since PEG's current labor and capital price level indexes are for 2008, it would be desirable to calculate new labor and capital price level indexes that reflect more recent (e.g., 2019) prices in Québec and the various service territories of the sampled U.S. companies.
- PEG uses its own FERC Form 1 data. We must therefore incur the cost of adding three years of data but need not purchase costly data from a commercial vendor such as SNL Financial. However, it is more efficient to purchase the right to use some business condition variables developed by PSE. PSE's construction standards index seems to be particularly pertinent in a study to benchmark HQT, which operates under severe winter weather conditions. PSE has also developed a useful forestation variable.
- HQT indicated in response to information request 5.3 of B-0265 (HQT-16, Document 1) that the Brattle Group was considering the use of a one hoss shay capital cost specification in its studies. Because one hoss shay has been used less often than other specifications in X factor studies, some issues concerning the usefulness and proper use of one hoss shay in X factor and benchmarking studies are unresolved and merit additional reflection. To obtain consultation on some of these issues, PEG retained the services of Dr. Jean-Paul Chavas, a distinguished microeconomist and chaired professor in the Department of Agricultural and Applied Economics at the University of Wisconsin.

- *CNE* and capital cost performance and productivity trends are issues in this proceeding as well as total cost performance and *PMF* trends. Calculations of *CNE* productivity merit close attention since these may be used to revise the X factor in HQT's current *MRI*. The *CNE* and capital cost of HQT should be benchmarked, as well as its total cost.[78]
- It is possible to expand the sample to include more companies which face business conditions similar to HQT's.
- Use of the alternative hyperbolic decay capital cost specification warrants consideration.
- There is no guarantee that Brattle will prepare an econometric total cost benchmarking study like those that regulators in Ontario and Massachusetts consider in choosing stretch factors.

4.3. Project Proposal and the Régie's Response

On 9 October 2020, the Régie sent AQCIE-CIFQ a request for an estimate of the cost of PEG's research. To afford the Régie some say in the direction of the research and reduce the risk of cost underrecovery, PEG submitted a detailed project proposal as well as a budget estimate. This proposal had the following core objectives.

1. Update the U.S. sample that PEG used in its recent Ontario transmission *MRI* proceedings to include 2017-2019 data.
2. Calculate 2019 labor and capital price level indexes.
3. Consider new business condition variables for the benchmarking study.
4. Use the upgraded and updated data set to develop econometric models of transmission *CNE*, capital cost, and total cost.
5. Calculate the *CNE*, capital, and multifactor transmission productivity trends of U.S. utilities in the Ontario sample.
6. Even though PEG uses code to calculate costs and productivity trends, another objective was to prepare working papers that include such calculations in Microsoft Excel spreadsheets.

[78] These costs were not separately benchmarked by either consultant in the Ontario studies.

7. Examine drivers of U.S. transmission productivity growth more closely and use these findings to consider 1) the appropriate sample period for choosing HQT's X factor and 2) the appropriate stretch factor.

8. Consider alternatives to the scale escalator in HQT's current *formule d'indexation* for *CNE* revenue and appropriate escalators for future formulas which can apply to capital as well as *CNE* revenue.

9. Process HQT data and use the econometric models to benchmark the *CNE*, capital, and total cost of HQT in recent years.

10. Since the Régie has little experience with studies of this kind, we proposed to include in the report a thoughtful discussion of appropriate methods for X factor and benchmarking studies, including the pros and cons of alternative capital cost specifications.

11. With the help of Dr. Chavas, consider some unresolved issues concerning the appropriateness and proper use of the one hoss shay specification.

12. Perform any tasks requested by the Régie in any later stages of the proceeding.[79] The additional tasks in these stages could include participation in a technical conference, preparation of information requests to Brattle and responses to theirs, and oral testimony.

In addition to these core tasks, PEG proposed some optional tasks for the Régie's consideration.

1. Add data for Hydro One transmission to the sample. This is also a sizable task because we cannot use the Hydro One data from the Ontario proceedings, which were obtained pursuant to a confidentiality agreement, and would have to gather these data from scratch.

2. Expand the sample from PEG's Ontario study to include some additional U.S. power transmitters that face business conditions that are similar to HQT's (e.g., Central Maine Power).

3. Develop a hyperbolic decay capital cost specification and use it to recalculate benchmarking (and possibly also productivity) results.

AQCIE-CIFQ transmitted PEG's research and cost proposal to the Régie on 30 October 2020. In its response to the proposal on 4 December, the Régie declined to approve a specific budget for the

[79] Subsequent stages have not as yet been announced.

work or to comment on the appropriate scope of the PEG study. The Régie's *Guide de Paiement de Frais* was cited as a reference for acceptable hourly rates. In light of the Régie's response, PEG is exposed to material financial risk in undertaking this multitask empirical study, which took several staff members several months to prepare.

4.4. Information Requests to HQT

PEG submitted four tranches of information requests (*demandes de renseignements* or *DDRs*) to HQT, including several follow-up questions. The correspondence was cordial, and the responses to our questions were generally fulsome. Some of the *DDR* responses influenced our research plan.

- Even though HQT has adopted a *modèle de gestion d'actifs*, it did not provide detailed data on the age of its system which could be used in cost benchmarking or the development of custom productivity growth benchmarks.[80]
- HQT's responses indicated that its retirements data are unsuitable for the use of a one hoss shay capital cost specification when benchmarking the company.[81][82]
- HQT's inability to provide an estimate of its dispatching expenses that is consistent with FERC Form 1 prompted us to spend a great deal of time considering possible fixes.

4.5. Revised Research Plan

We accordingly decided to trim certain tasks from the research plan we presented to the Régie. Here are some examples.

- A hyperbolic decay capital cost specification was not developed.
- Hydro One Networks was not included in the sample.
- No econometric productivity growth benchmarks were developed.
- No new work was done to determine the drivers of recent negative productivity growth in the transmission industry.

[80] See, for example, B-0268 (HQT-16, Document 2), Response 5.1.

[81] See, for example, B-0265 (HQT-16, Document 1), Response 5.3 and B-0268 (HQT-16, Document 2), Response 8.1.

[82] One hoss shay could still be used in the productivity research.

- The hours for the work of Dr. Chavas were scaled back.
- Ironically, the heightened uncertainty about cost recovery prompted us to spend *more* time preparing questions for HQT in order to increase the relevance of our study to its situation.

4.6. Research Challenges

PEG has found power transmission benchmarking and productivity studies to be particularly difficult due to industry change, idiosyncratic data, and the limited number of prior studies in the public domain. Benchmarking the cost performance of HQT, with its different cost accounting, posed additional complications. Under these circumstances, PEG appreciates the Régie's deadline extensions. While HQT provided reasonable responses to information requests the process was cumbersome. New information may arise in later stages of this proceeding which prompts us to revise our benchmarking results.

5. Empirical Research

5.1. U.S. vs. Canadian Transmission Data

U.S. Data

Power transmission in the United States is performed chiefly by investor-owned utilities.[83] Most of these companies also distribute power, and many generate power. Transmission services of other utilities are often used, especially by utilities still engaged in generation. The division between generation, transmission, and distribution systems varies somewhat across the industry. Utilities typically count the substations associated with power plants that they own as transmission facilities. They frequently do not own substations associated with independently-owned power plants.

<u>Advantages</u>

U.S. data have material advantages in transmission cost and productivity research.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of major investor-owned utilities that transmit power. The primary source of these data is FERC Form 1. Most costs attributable to transmission are itemized on this form. The transmission services provided by these utilities are similar to those that HQT provides. FERC Form 1 data are also available on important characteristics of transmission networks (e.g., the length of transmission lines and the capacity of substations).
- Transmission costs are further itemized, and this permits some useful customization of cost studies. For example, the cost of using transmission systems of other utilities is itemized for easy removal.
- PEG has gathered data, from FERC Form 1 and antecedent forms, on the net value of transmission plant (and other kinds of plant) in 1964 and the corresponding gross plant additions since that year. This increases the accuracy of using monetary methods to measure capital costs and quantities.

[83] Some federal utilities and rural electric cooperatives also provide power transmission services in the States. A notable example is the Bonneville Power Administration.

- Regional Handy Whitman indexes are available on trends in the costs of transmission plant construction.

These advantages make U.S. data the best in the world for calculation of the costs and price and quantity indexes that are needed to calculate transmission *CNE*, capital, and multifactor productivity trends and to develop econometric benchmarking models for *CNE*, capital cost, and total transmission cost.

Disadvantages

There are also some notable disadvantages to using U.S. data in transmission cost and productivity research.

ISO Complications We noted in Section 2.2 above that, between 1996 and 2005, many U.S. utilities (mostly located in California, Texas, other south-central, north-central, and northeastern states) became (and have generally remained) ISO members while others (mostly located in northwest, mountain-west, and southeastern states) have not.[84] These organizations perform certain activities (e.g., dispatching) which were previously performed by their members. Members permit the organization to use some of their assets and may also provide it with operation and maintenance services. Members also purchase their transmission services from the organization. The organization bills members for its own costs (e.g., costs incurred for dispatching) and for costs of services it purchases from transmission owners.

This restructuring of the transmission industry in certain regions complicates statistical cost research using U.S. data. For example, the costs that utilities incurred for services that they previously provided (e.g., dispatching) could decline after they joined because these activities were now performed by the organization, and these costs could be lower than those of transmitters that were not ISO members. ISO members may, on the other hand, face new cost pressures. For example, tasks that the organization takes over may become more difficult, organizations may perform new tasks (e.g., market monitoring), and members may be charged for these new and expanded tasks. ISO members may also be encouraged by their ISOs to incur higher costs on certain tasks (e.g., maintenance). Costs may then grow more rapidly for members and exceed those of transmitters who are not members.

[84] We will use the term ISOs to encompass regional transmission organizations as well.

Restructuring has also caused members to report some costs differently than they did in the past. For example, costs of capital (e.g., computer hardware and software, communications equipment, and structures) which ISOs incur in system operation and bill to utilities will be recorded by the utilities as *CNE,* whereas utilities treat costs for these kinds of capital as capital costs when they are the owners. Many vertically-integrated utilities have in the last two decades increased their reliance on unbundled transmission services to obtain power supplies. Changes in how these costs were reported can affect research results.

FERC Order 668 in December 2005 changed reporting guidelines for transmission costs. Here are some examples.

- New accounts have been established for (the gross value of) Regional Transmission and Market Operation Plant. The new categories include computer hardware (382), computer software (383), communications equipment (384), and miscellaneous plant (385). Accounts 569.1-569.4 were established, under transmission load dispatching, for maintenance of these same assets. These accounts were intended chiefly for use by ISOs but some utilities may have elected to start reporting costs in these same accounts.
- Accounts 575 and 576 were established for regional market *CNE*. [85]
- Transmission dispatching expenses (in Account 560) were itemized, and three subaccounts were established to report utility payments for costs that ISOs bill to them:
    - 561.4 Scheduling, System Control, and Dispatching;
    - 561.8 Reliability Planning and Standards Development; and
    - 575.7 Market Facilitation, Monitoring and Compliance.

Data problems posed by transmission sector restructuring could be mitigated if reported transmission costs were appropriately itemized and utilities reported these costs consistently. However, data problems have been observed.

- The new data guidelines occasioned by FERC Order 668 did not occur until many California, Midwestern, New York, and New England utilities had been ISO members for several years.

[85] These costs are generally small.

This has produced some shifts in where ISO costs are reported. As one example, a utility might have initially reported certain ISO costs as transmission by others expenses (which are excluded from our calculations) and then reported them as dispatching expenses.

- Utilities seem to have reported ISO costs incurred *before* FERC Order 668 inconsistently, with some reporting them as transmission by others expenses and others reporting them as miscellaneous transmission expenses.
- ISO members do not seem to have reported their ISO costs consistently since the implementation of FERC Order 668. For example, while many members have consistently reported sizable costs for ISO services in accounts like 561.8, as directed by Order 668, many have not.[86] This may be due in part to varied ISO policies and the peculiarities of formula rate plans.
- Some utilities seem to have reported, as miscellaneous transmission or dispatching expenses, sizable costs that other utilities report as transmission by others expenses.
- Whether or not utilities are ISO members, they have some discretion as to whether to report dispatch expenses in FERC Account 561 (Load Dispatching) under Transmission Expenses or FERC Account 556 (System Control and Load Dispatching) under Other Power Supply Expenses.

Since power transmission is a highly capital-intensive business, these data problems occasioned by restructuring of the sector might not matter greatly if the focus of X factor and benchmarking work is *total* transmission cost. However, *CNE* is a particular focus of this proceeding due to the design of the transmission *MRI.*

Other Problems Here are some other problems with U.S. transmission data.

- Peak demand data are idiosyncratic, as discussed further below.
- It is difficult to adjust capital cost calculations for sales and spinoffs of *postes de départ* that resulted from the restructuring of power markets.

[86] Most of the companies in our sample that did not are members of PJM or the New York ISO.

- FERC Form 1 does not itemize some costs by U.S. electric utilities between their production, transmission, distribution, and customer services. The values of transmission-related computer hardware, telecommunications equipment, and structures typically are included in general plant, and the value of computer software is in intangible plant.
- Since most U.S. investor-owned utilities, like Hydro-Québec, are engaged in other electric services, they incur certain general costs that are difficult to accurately allocate between these services.

Canadian Data

Power transmission in Canada is performed chiefly by Crown corporations that provide most or all transmission services in an entire province. Like Hydro-Québec, many of these utilities also have extensive generation and distribution operations.

Advantages

Canadian transmission cost data have the major advantage of being denominated in Canadian dollars. The challenging task of comparing U.S. and Canadian input price levels accurately can therefore be sidestepped. Transmitters in other provinces, like their U.S. counterparts, appear to play a role similar to that of HQT.

Disadvantages

Data on transmission operations of utilities in the various provinces of Canada are not standardized, one reason being that rate regulation occurs at the provincial level. The many years of consistent data needed for monetary capital cost specifications are available in just a few provinces (e.g., Ontario), and even in these provinces are generally not available before 2000. In its Ontario study for Hydro One, PSE invited nine transmission utilities in other provinces to participate but none did so.

Resolution

Given the many advantages of U.S. transmission data, the problems with Canadian data, and the budget uncertainties in this project, we decided to base our productivity and econometric cost research solely on U.S. data. PSE took the same approach in its studies for Hydro One Networks.

5.2. Data Sources Used in This Study

FERC Form 1 was the source of data on transmission costs, network characteristics, and peak demand of U.S. electric utilities which we used in our research. 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").[87] 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.

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 ("M&S") 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 Québec locations were obtained from RSMeans. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates. Two of the business condition variables we used in our econometric cost research were obtained from PSE.

5.3. Sample

Data for 51 U.S. power transmitters were used in our productivity trend research. Data for 46 U.S. transmitters were used in our econometric research. A larger sample is possible for the productivity research because data are not required for all of the business condition variables. Table 2 lists the sampled utilities.

Various problems limited the size of the sample. Some utilities were involved in mergers or acquisitions, and some sold or spun off transmission assets that came to be owned by "transcos." These transactions complicate monetary capital cost and quantity calculations. Some had missing or implausible data (e.g., unusual ways to report ISO costs.)

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

Table 2

Utilities Sampled in PEG's Studies

Alabama Power	*Kansas Gas and Electric*
ALLETE (Minnesota Power)	Kentucky Utilities
Arizona Public Service	Louisville Gas and Electric
Atlantic City Electric	Mississippi Power
Avista	Monongahela Power
Baltimore Gas and Electric	New York State Electric & Gas
Central Hudson Gas & Electric	Niagara Mohawk Power
Cleco Power	Northern States Power - MN
Commonwealth Edison	Oklahoma Gas and Electric
Connecticut Light and Power	Orange and Rockland Utilities
Consolidated Edison of New York	PacifiCorp
Delmarva Power & Light	*PECO Energy*
Duke Energy Carolinas	Potomac Electric Power
Duke Energy Florida	Public Service Company of Colorado
Duke Energy Indiana	Public Service Electric and Gas
Duke Energy Ohio	Rochester Gas and Electric
Duke Energy Progress	*San Diego Gas & Electric*
Duquesne Light	South Carolina Electric & Gas
El Paso Electric	*Southern California Edison*
Empire District Electric	Southern Indiana Gas and Electric
Florida Power & Light	Southwestern Public Service
Gulf Power	Tampa Electric
Idaho Power	Tucson Electric Power
Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	West Penn Power
Kansas City Power & Light	

Notes:
Italicized companies are only included in the productivity research.

The sample period for our econometric cost research was 2004-2019 due to data limitations. Most notably, this was the first year for which data were available for our preferred peak demand variable in this research. The full sample period for our productivity research was 1996-2019.

5.4. Variables Used in the Empirical Research

Costs

The cost of power transmission considered in our productivity and econometric studies was the sum of applicable capital costs and *CNE*. 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.[88] Plant was valued in current dollars. In addition to costs of *transmission* plant ownership, we included a sensible share of the costs of *general* plant ownership. Taxes (and franchise fees) were excluded, and no provisions were made for tax-related accelerated depreciation.

CNE that we considered comprised applicable transmission *CNE* and a sensible share of applicable administrative and general *CNE.*[89] We excluded some categories of transmission *CNE* from our *productivity trend* calculations out of concern that 1) they were sensitive to the restructuring of the transmission industry and 2) this restructuring is of limited relevance to an *MRI* for HQT. The FERC Form 1 categories excluded on these grounds were Transmission of Electricity by Others (account 565), Load Dispatching (accounts 561.1-561.8), Miscellaneous Transmission Expenses (566), and Regional Market Expenses (accounts 575 and 576). Small differences in the cost exclusions that we made for the econometric benchmarking model are discussed in Section 5.7 below.

Administrative and general expenses that we considered included those for the following categories:

- administrative and general salaries and office supplies and expenses less administrative expenses transferred;
- outside services employed;
- property insurance;

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[88] Further details of our capital cost calculations are provided in Appendix section A.1.

[89] We apportioned to transmission cost a share of each American utility's general costs equal to the share of included transmission *CNE* in its net *CNE*. Since general costs are tied to the management of labor, in calculating net *CNE* we excluded some *CNE* that are large relative to their labor cost component. Examples of these excluded expenses include those for energy, transmission by others, and uncollectible bills.

- injuries and damages;
- regulatory commission expenses;
- general advertising expenses;
- miscellaneous general expenses;
- rents; and
- general plant maintenance;

Pension and other benefit expenses were excluded from both studies, as they were from our recent Ontario transmission studies. One reason is that pension expenses can be sensitive to volatile external business conditions such as stock prices. Another is that such expenses receive Y factor treatment in the *MRI* of HQT. The health insurance obligations of U.S. and Canadian utilities can differ considerably. In Canada, an additional problem with including pension and benefit expenses is the lack of federal labor price indexes that correspond to them as well as to salaries and wages. Pension and benefit (e.g., health care) expenses are reported on a consolidated basis on FERC Form 1, so it is not possible to exclude pension expenses and include other benefit expenses. We also excluded from both studies reported costs that the U.S. utilities incurred for power production and procurement, power distribution, customer accounts, customer service and information, sales, and gas utility services.

Input Prices

The input price indexes used in our study were designed to compare the price *levels* of utilities at each point in time as well as the price *trends* over time. This capability was needed because these indexes were used in both the econometric cost research (where differences between utilities in the level of input prices in a given year matter) and the productivity index research (where they do not).

CNE

Labor For the year 2019 we calculated indexes of labor price levels for HQT and the sampled U.S. utilities. Occupational Employment Statistics ("OES") survey data from the U.S. Bureau of Labor Statistics were used to calculate wage rate indexes as weighted averages of comparisons of the hourly wage rates, for various job categories established in the occupational classification code, using cost share weights that correspond to the electric utility industry. These data were available for numerous metropolitan statistical areas, and we computed an average of the results for the areas in each service territory using population weights.

To calculate a comparable wage rate index value for HQT in 2019, we compared U.S. and Québec wage rates for pertinent job categories. These calculations used, in addition to U.S. Bureau of Labor Statistics data, data from Statistics Canada on hourly wage rates that were itemized by job category using the National Occupational Classification ("NOC").

For other years of the sample period, values of each company's wage rate index were calculated by adjusting these levels for changes in labor price trend indexes. For the U.S. utilities we used regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For HQT, we calculated the wage rate trend using the average hourly earnings for Québec industry reported by Statistics Canada.

Materials and Services The prices that U.S. utilities pay for materials and services were assumed to be the same in a given year but to inflate over time at the rate of the U.S. gross domestic product price index. 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 consumer products, business equipment, and exports. For the material and service price inflation of HQT we used Statistics Canada's gross domestic product implicit price index for final domestic demand. This is preferable to the more comprehensive GDPIPI because the latter is quite sensitive to volatile prices of Canada's sizable commodity exports. Material and service prices in the U.S. and Canada were patched using U.S./Canadian purchasing power parities ("PPPs") for gross domestic product. PPPs summarize the relative prices of a wide range of products included in the gross domestic product.

The summary *CNE* price indexes used in our research featured subindexes for labor and materials and services.[90] Growth in each summary index was a weighted average of the growth of the two subindexes. In these calculations we used company-specific, time-varying cost-share weights that we calculated from FERC Form 1 and HQT data.

[90] The formulas for our input price indexes are discussed further in Appendix A.1.

Capital

A monetary approach to the calculation of capital cost was used in both the productivity and benchmarking research. As discussed in Section 3.4 above, this required us to construct capital (service) price indexes from asset price indexes and rates of return on capital. A multistep process was used in these calculations. We first calculated an index of construction cost levels which varied between the service territories of sampled utilities in 2019 in proportion to the relative cost of local construction as measured by total (material and installation) heavy construction cost indexes published by RSMeans.[91] Index values are available for multiple cities in the service territories of most sampled utilities. For these utilities, we computed a weighted average of these values using as weights the approximate populations of the pertinent cities.[92] For HQT, we used only the construction cost index value for Montréal (the highest reported for Québec) out of concern that RS Means reported no values for remote areas that HQT serves which might have higher construction costs.

To obtain asset price index values for other years, we trended the values for 2019 using asset price trend indexes. As asset price trend indexes for U.S. utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant. As general plant asset price indexes for these utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction.

For HQT we developed an asset price trend index from the average annual growth rates of two indexes. One was the product of the Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant in the North Atlantic region and the PPP for gross domestic product. The other was Statistics Canada's implicit capital stock deflator for the utility sector of Québec. Statistics Canada includes in the utility sector power generation and distribution, gas distribution, and water and sewer utilities as well as power transmission. We assigned equal weights to the trends in these two indexes.

For the rates of return of U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[93] For debt we used the embedded average interest rate on long-term debt of a large group

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[91] *Heavy Construction Costs with RSMeans Data*, Gordian Publishers, 34th annual edition, 2020.

[92] When multiple utilities served a city, we counted only a portion of the population.

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

of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.[94] For HQT, we employed the approved weighted average cost of capital that is reported in their *revenu requis* tables.

The construction of capital service prices from these components is discussed further in Appendix A.

Multifactor

The summary multifactor input price indexes that we used in the econometric cost research were constructed for each transmitter by combining the summary capital and *CNE* price indexes using company-specific, time-varying cost share weights.

Output Variables

Two output variables were used in our research: length of transmission line and ratcheted maximum peak demand. We ratcheted the peak load data by using in each year the highest value yet attained since the start of the sample period. This is a proxy for the expected maximum peak demand that we believe drives transmission cost.

U.S. line length data were drawn from the Transmission Line Statistics on page 422 of FERC Form 1. Two sources of peak demand data are available on FERC Form 1.

- **Monthly Transmission System Peak Load** (page 400) comprises firm network service, long-term firm point-to-point, other long-term firm, short-term firm point-to-point, and other. Most of these categories are firm service. These data have been gathered since 2004.
- **Monthly Peak Load** (page 401b) is not expressly a *transmission* system peak and seems instead to have been intended originally as a measure of peak power *supply* to retail and requirements sales for resale customers (e.g., munis and cooperatives). It expressly excluded the demand at the peak which is associated with non-requirements sales for resale. However, the definition has changed and is now is less clear.

The peak demand data available for HQT are drawn from response 1.23 of HQT-16 Document 1 (the first tranche of data requests). These data pertain to *demandes de pointes du reseau de transport*,

[94] 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.

which HQT translates as "peaks coinciding at network peak demand". These peaks are decomposed with respect to "native load" (*charge locale*) and "point to point" services. HQT's point-to-point load at the peak (which occurs in the winter) is quite variable and typically ranges between 5-15% of the total. Most of it is firm.

The two peak demand variables available on Form 1 each have advantages in transmission benchmarking and X factor studies for HQT.

Arguments for Transmission System Peak Load

- This is the more accurate measure of *transmission* system peak loads.
- It matches up better with HQT's peak load data.
- Monthly peak load data are sensitive to the restructuring of the US electric utility industry since, for some companies, the sale or spin off of generation reduced requirements sales for resale.

Arguments for Monthly Peak Load

- Data are available for a considerably longer sample period, thereby permitting calculation of longer-term productivity trends that should interest the Régie.
- The longer sample period also facilitates use of a ratcheted peak demand variable.
- Data are also available for a few more utilities.
- Some companies report *transmission* peaks only for a multi-utility *system*, and it is difficult to apportion these between the constituent companies accurately.
- While restructuring may have caused the monthly peak demand growth of some companies to slow as requirements sales for resale were suspended, many companies did not have many requirements sales for resale before restructuring. Also, ratcheting peak demand mitigates this problem.
- Transmission peak may include some non-firm load that shouldn't drive cost.

Based on these considerations, we decided to use the *monthly* system peak data in the *productivity* research and the *transmission* system peak data in the *econometric* research.

We accorded the two scale variables in our econometric models a translog treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. To reduce controversies over functional forms, no second-order terms were included for the other variables in the model. Functional form issues are discussed further in Appendix A.2.

Other Business Condition Variables

Five other business condition variables were included in our econometric total cost model. Three of these address characteristics of the transmission system. These variables were substation capacity (measured in MVA) per substation, substations per line mile, and the share of overhead assets in the gross value of transmission line assets.[95] The U.S. data for these variables were obtained from FERC Form 1. Analogous data for HQT were provided by the Company in response to information requests. We expect the parameters of the first two variables to have positive signs, while that for the third variable should have a negative sign because undergrounding of transmission facilities is especially costly.

The model also includes the construction standards index for transmission tower construction which PSE developed[96] in the Hydro One proceeding and the share of transmission plant in the utility's non-general gross plant value. The former variable indicates how construction standards vary with weather in a transmitter's service territory. The latter variable should indicate the extent to which the utility was unable to realize economies of scope from the joint provision of transmission and distribution (and in some cases generation) services. We expect both of these variables to have positive parameters.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the business conditions that are specified in the cost model. Trend variables thereby capture the net effect on cost of changes in diverse conditions, such as technology and X inefficiency, which are otherwise excluded from the model. Parameters for such variables often have

[95] For the sampled U.S. utilities, the extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is capital-intensive, high overheading should generally lower total cost.

[96] See Appendix A3 for details on PSE's variables.

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.

The *CNE* model includes the same scale variables, MVA per substation, the scope economies variable, a variable indicating ISO membership, and a variable that PSE developed which measures the extent of forestation in each company's service territory.[97] We expect all of these variables to have positive parameters save the scope economies variable.

Our capital cost model contains all of the variables in the total cost model. This is unsurprising since transmission is highly capital-intensive. We expect the parameters of these variables to have the same signs.

5.5. Econometric Research

Total Cost

The dependent variable in our econometric total cost research was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.[98]

Results of our econometric total cost research are reported in Table 3. This table includes parameter estimates and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero can be rejected at a high level of confidence. These significance tests were used in model development.

Examining the results in the table, it can be seen that the parameter estimates of the business condition variables in the model all have plausible values.[99] Our research indicates that the transmission costs tended to be higher to the extent that sampled utilities had

- higher ratcheted maximum peak demand;
- longer transmission lines;
- more capacity per substation;

[97] To save money we used the value for the forestation variable which PSE had assigned to Hydro One Networks in the Hydro One transmission *MRI* proceeding. See Appendix A3 for details on PSE's variables.

[98] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

[99] This remark pertains to the "first order" terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 3

Econometric Model of Transmission Total Cost

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
nsub0919perym = Number of substations per miles of transmission line
load_tx = Construction standards index
pctpoh = Percent of transmission plant that is overhead
pctptx = Percent of plant transmission
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.402	14.50	0.000
ym2	0.171	5.45	0.000
yptx	0.549	21.31	0.000
yptx2	0.207	6.78	0.000
ymyptx	-0.168	-8.20	0.000
mva0919pernsub0919	0.150	7.60	0.000
nsub0919perym	0.077	4.17	0.000
load_tx	0.174	4.65	0.000
pctpoh	-0.437	-10.86	0.000
pctptx	0.341	15.86	0.000
trend	0.013	8.57	0.000
Constant	19.028	960.87	0.000

System Rbar-Squared	0.948
Sample Period	2004-2019
Number of Observations	711

- more substations per line mile;
- higher construction standards due to weather challenges;
- more transmission assets underground; and
- transmission plant that constituted a larger share of total non-general plant.

The parameter estimates for the two scale variables indicate that ratcheted peak demand had a long-run cost elasticity of 0.549% whereas that for transmission line length was 0.402%. All three second-order (quadratic and squared) output variables had highly significant parameter estimates.

The parameter estimate for the trend variable suggests that transmission cost tended to *rise* over the full sample period by about 1.28% annually for reasons that aren't explained by the business condition variables in the model. The 0.948 adjusted R-squared for the model indicates that it has substantial explanatory power.

Capital Cost

The dependent variable in our econometric capital cost research was *real* capital cost: the ratio of capital cost to a capital input price index. Results of our econometric capital cost research are reported in Table 4. Examining the results in the table, it can be seen that the parameter estimates of all of the business condition variables in this model also have plausible values.[100] Our research indicates that transmission capital *cost* tended to be higher to the extent that sampled utilities had

- higher ratcheted peak demand;
- more transmission miles;
- more substation capacity per substation;
- more substations per line mile;
- more transmission plant underground;

[100] This remark pertains to the "first" order terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 4

Econometric Model of Capital Cost

VARIABLE KEY

ym =	Miles of transmission line
ym2 =	ym squared
yptx =	Transmission peak
yptx2 =	yptx squared
ymyptx =	ym · yptx
mva0919pernsub0919 =	Substation capacity per number of stations
pctpoh =	Percent of transmission plant that is overhead
pctptx =	Percent of plant transmission
nsub0919perym =	Number of substations per miles of transmission line
load_tx =	Construction standards index
trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.396	13.78	0.000
ym2	0.048	1.58	0.115
yptx	0.614	23.38	0.000
yptx2	0.183	6.24	0.000
ymyptx	-0.092	-4.70	0.000
mva0919pernsub0919	0.159	7.78	0.000
pctpoh	-0.435	-12.45	0.000
pctptx	0.390	17.80	0.000
nsub0919perym	0.082	4.54	0.000
load_tx	0.260	7.14	0.000
trend	0.009	6.07	0.000
Constant	14.196	533.10	0.000
System Rbar-Squared	0.957		
Sample Period	2004-2019		
Number of Observations	711		

- more transmission plant relative to generation and distribution plant; and
- higher construction standards due to severe weather.

The parameter estimates for the scale variables in this model indicate that ratcheted peak demand had a long-run cost elasticity of 0.614% whereas that for transmission line length was 0.396%. Two of the three second-order output variables had highly significant parameter estimates.

The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by 0.85% annually for reasons that aren't explained by the business condition variables in the model. The 0.957 adjusted R-squared for the model is similar to that for the total cost model and remarkably high.

CNE

The dependent variable in our econometric *CNE* research was *real CNE*: the ratio of *CNE* to the *CNE* input price index. Results of our econometric *CNE* research are reported in Table 5. Examining the results in the table, it can be seen that the parameter estimates of all of the business condition variables in this model are also plausible.[101] Our research indicates that transmission *CNE* tended to be higher to the extent that sampled utilities had

- higher ratcheted maximum peak demand;
- longer transmission lines;
- more substation capacity per substation;
- more transmission plant relative to generation and distribution plant;
- more service territory forestation; and
- ISO membership.

The parameter estimates for the scale variables in this model indicate that ratcheted peak demand had a long-run cost elasticity of 0.423% whereas that for transmission line length was 0.372%. All of the second-order terms had highly significant parameter estimates. Thus, the relationship of cost

[101] This remark once again pertains to the "first order" terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 5

Econometric Model of Transmission *CNE*

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
pctptx = Percent of plant transmission
pforgis1 = Percent forestation in service territory
rto = Binary variable indicates RTO/ISO member
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.372	10.06	0.000
ym2	0.664	14.37	0.000
yptx	0.423	12.37	0.000
yptx2	0.463	7.87	0.000
ymyptx	-0.584	-20.84	0.000
mva0919pernsub0919	0.072	2.64	0.009
pctptx	0.231	7.41	0.000
pforgis1	0.046	5.11	0.000
rto	0.189	5.69	0.000
trend	0.021	6.88	0.000
Constant	17.314	485.72	0.000

System Rbar-Squared	0.796
Sample Period	2004-2019
Number of Observations	711

to output was highly nonlinear. The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by a brisk 2.1% annually for reasons that aren't explained by the business condition variables in the model. This result was likely influenced by the EPAct.

The 0.796 adjusted R-squared for the model is considerably lower than those of the total cost and capital cost models. This gives us less confidence in the appropriateness of our econometric *CNE* benchmarks. *CNE* is affected by numerous business conditions that are difficult to model accurately. These include ice storms, tornados, hurricanes, wildfires, reliability standards, system age, and maintenance cycles.

5.6. Productivity Research

Methodology

We calculated indexes of the *CNE*, capital, and multifactor transmission productivity of 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 output and input quantity indexes. Size-weighted averages of these growth rates were then calculated. As noted in Section 3.1, size weighting makes particular sense in research to determine the X factor of a large utility like HQT.

To measure output growth we used multidimensional indexes with cost elasticity weights as discussed in Section 3.1. The output variables were the two that we identified in our econometric research: line length and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric total cost research were used to establish weights. These weights were about 58% for ratcheted maximum peak demand and 42% for line length.

We encourage the Régie to consider multidimensional output indexes of this kind as a scale escalator in HQT's revenue cap indexes. The 58/42 weights are appropriate for a comprehensive revenue cap index. In a revenue cap index applicable only to *CNE* revenue, the 53% ratcheted peak/47% line length weights from our *CNE* model are more pertinent.

In calculating input quantity indexes for the U.S. utilities, we broke down their applicable costs into those for transmission capital, general capital, labor, and material and service inputs. Each of these input groups had its own quantity subindex. We calculated *summary CNE* and capital quantity indexes using company-specific time-varying cost-share weights. The trend in each company's multifactor input quantity index was a cost-weighted average of the trends in the labor, M&S and capital subindexes.

Industry Trends

Table 6 reports results of our productivity calculations for the full sample. We found that the growth in the transmission *PMF* of sampled U.S. utilities averaged a 2.26% annual decline over the fifteen-year 2005-2019 sample period but a more positive 0.62% average annual decline over the full 24-year 1996-2019 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. *CNE* productivity averaged a 1.74% annual decline over the last 15 years and a 0.68% annual decline over the full sample period. The productivity of transmission capital averaged a 2.16% annual decline over the last fifteen years and a 0.46% annual decline over the full sample period.

Our estimates of transmission output do not reflect any possible improvements in transmission reliability, bulk power market performance, or increased reliance on renewable resources that may have occurred during the sample period. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. [102]

5.7. Cost Benchmarking

HQT Background

We begin this section by discussing key aspects of HQT's situation which should be considered in appraising its costs.

<u>Overview</u>

Hydro-Québec is a crown corporation that generates, transmits, and distributes most electricity in the province of Québec. HQT is the Company's transmission division. Québec has Canada's second largest provincial economy and a population and transmission service territory area comparable to that of Arizona, of Colorado, Wyoming, and Montana combined, or of Minnesota, the Dakotas, and the upper peninsula of Michigan combined.

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[102] Denis Lawrence, Tim Coelli and John Kain, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report*, prepared for the Australian Energy Regulator, October 15, 2020, pp. 6-7.

Table 6

U.S. Transmission Productivity Results: 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	Productivity: MFP	Productivity: O&M	Productivity: Transmission Capital	Productivity: Allocated General Plant
1996	1.2%	-0.5%	0.4%	-0.9%	1.2%	1.7%	0.8%	2.2%	0.0%
1997	0.9%	-1.4%	-0.5%	-1.2%	-4.4%	2.3%	1.4%	2.1%	5.3%
1998	2.2%	-0.4%	3.9%	-1.9%	2.1%	2.6%	-1.7%	4.2%	0.1%
1999	2.8%	-2.1%	-4.3%	-1.9%	-2.3%	4.9%	7.1%	4.6%	5.1%
2000	0.4%	-0.1%	6.3%	-1.3%	10.5%	0.5%	-5.9%	1.7%	-10.1%
2001	1.8%	-0.6%	-0.8%	-0.9%	13.4%	2.4%	2.6%	2.6%	-11.6%
2002	0.7%	-1.7%	-6.2%	-0.4%	-4.3%	2.4%	6.9%	1.0%	4.9%
2003	1.4%	-0.2%	3.0%	-0.7%	1.2%	1.5%	-1.6%	2.0%	0.2%
2004	0.6%	-0.1%	0.5%	-0.2%	-1.5%	0.7%	0.1%	0.9%	2.1%
2005	2.7%	0.9%	4.6%	0.1%	-1.8%	1.8%	-1.8%	2.7%	4.5%
2006	2.3%	1.4%	3.3%	0.4%	-0.8%	0.9%	-1.0%	1.9%	3.1%
2007	0.0%	2.9%	6.1%	1.4%	0.2%	-2.8%	-6.1%	-1.3%	-0.2%
2008	0.3%	1.9%	3.5%	1.2%	1.0%	-1.6%	-3.2%	-0.9%	-0.7%
2009	-0.1%	3.1%	4.2%	2.5%	2.2%	-3.2%	-4.3%	-2.6%	-2.3%
2010	0.7%	2.9%	5.4%	2.2%	-1.4%	-2.2%	-4.7%	-1.5%	2.0%
2011	0.3%	2.3%	1.1%	2.9%	2.9%	-2.0%	-0.8%	-2.5%	-2.6%
2012	0.4%	1.8%	2.0%	2.1%	5.5%	-1.4%	-1.6%	-1.7%	-5.1%
2013	0.3%	4.3%	2.1%	4.9%	6.2%	-4.0%	-1.7%	-4.6%	-5.9%
2014	1.2%	4.2%	-1.5%	5.0%	0.4%	-3.0%	2.7%	-3.8%	0.9%
2015	0.4%	4.5%	-2.8%	5.9%	1.3%	-4.2%	3.1%	-5.5%	-0.9%
2016	0.8%	5.0%	5.9%	4.7%	9.6%	-4.2%	-5.1%	-3.9%	-8.8%
2017	0.1%	3.1%	-0.8%	3.7%	2.2%	-3.0%	0.9%	-3.6%	-2.2%
2018	0.8%	4.3%	7.2%	3.1%	3.9%	-3.4%	-6.3%	-2.3%	-3.1%
2019	0.7%	2.3%	-3.0%	3.4%	6.6%	-1.6%	3.7%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**1.58%**	**1.64%**	**1.42%**	**2.25%**	**-0.62%**	**-0.68%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**3.00%**	**2.48%**	**2.90%**	**2.54%**	**-2.26%**	**-1.74%**	**-2.16%**	**-1.80%**

[1] All growth rates are calculated logarithmically.

HQT’s provincial loads lie chiefly south of the Laurentian Plateau and are concentrated in the St. Lawrence Valley. The low-cost hydroelectric resources that are used to supply most power are meanwhile scattered across the plateau. HQT also accesses power from more than 40 wind farms and from small hydro, biomass and biogas cogeneration stations that are owned by independent producers (*producteurs privés*). The totality of generation volumes that HQT handles well exceed provincial loads, and around 20% of power deliveries are outside Québec. The transmission system has recently expanded to access new hydroelectric and wind resources in eastern Québec and to strengthen transmission capacity to the growing Montréal area. Facilities under construction will increase capacity to receive power from generators in eastern Québec and to deliver power to the States.

As a transporter of large power quantities over long distances, HQT has North America's most extensive transmission system, with more than 30,000 km of lines and more than 500 substations (*postes*). Transmission accounts for about 1/3 of Hydro-Québec's net plant value, substantially larger than the share of distribution. This is the reverse of the typical pattern of investor-owned utilities in the States.[103]

Transmission of large amounts of power over long distances has over the years encouraged HQT to use unusual and innovative technologies. These include 735 kV alternating current ("AC") lines, a high-voltage direct current ("DC") line, new tower designs, and remote monitoring systems. HQT also owns an extensive telecommunications system with thousands of km of fibre-optic cables and high-capacity microwave links. This is used for system control and for voice and data transmission via mobile radio communications for jobsites and work crews.

HQT operates asynchronously from North America's Eastern Interconnection. Its system therefore constitutes a separate interconnection, like that of the Electric Reliability Council of Texas. Special converters are used to export power to other provinces and the United States.

A sizable portion of HQT's access to transmission corridors has been achieved by easements rather than land ownership. At the end of 2019, land accounted for less than 1% of HQT's net plant value. Roughly 69% of the land that HQT owns is used as sites for *postes* rather than *lignes*.[104]

<u>Cost Challenges and Cost Advantages</u>

Challenges In addition to the great distances over which power must be carried, HQT faces other special challenges.

- The receipt points for a great deal of the power transmitted are remote. Many facilities are distant from good roads. Thus, HQT confronts special logistical challenges.

[103] These utilities typically own both transmission and distribution ("T&D") plant, as noted above, and the value of distribution plant is much larger.

[104] B-0268 (HQT-16, Document 2) *response* 3.1.

- Hard rock is close to or at the surface on much of the plateau, making it especially difficult to establish footings for structures.

- Transmission lines must traverse terrain that is hilly, forested, and/or incised by sizable lakes and rivers that include the broad St. Lawrence.

- Winters are cold throughout the region served, and ice storms have in the past caused major disruptions of transmission service. *Postes* are sometimes housed in structures.

- Substations at Hydro-Québec's generation facilities are owned by HQT. Since HQP owns most of the massive generating capacity in the province, these *postes de départ* are unusually numerous. The *postes de départ* of *producteurs privés* are typically owned and operated by the producers. However, for reasons of equity and in conformance with the *Tarifs et conditions des services de transport d'Hydro-Québec*, HQT reimburses these producers for these costs.[105] Costs of these *remboursements* are capitalized.

- Montréal is a large metropolitan area with a population similar to that of Minneapolis-St. Paul in the States. Costly undergrounding of some transmission facilities is required.

- Many of HQT's assets are approaching replacement age. HQT has adopted a *modèle de gestion d'actifs* to optimize the age of assets. This has placed upward pressure on its *CNE*.

- The need for special converters to export power has been noted.

Advantages HQT also has some cost advantages.

- Its large operating scale has permitted the realization of scale economies.

- Since the James Bay project roughly doubled the size of HQT's network, growth of the system has been gradual. Even sizable system expansions like the Romaine project in eastern Québec tend to be modest in percentage terms.

- Hydro-Québec's extensive involvement in generation and distribution as well as transmission should permit the realization of scope economies.

[105] HQT-16, Document 1, *reponse* 1.7.

- Ownership by the provincial government permits Hydro-Québec to borrow money at low rates.
- Hydro-Québec pays no income taxes. These taxes can account for more than 20% of capital cost.

Corporate Structure

Special features of Hydro-Québec's corporate structure merit note.

- HQT was established as a separate business unit (*unité d'affaires*) in 1997. This move, which FERC Order 888 encouraged, helped to separate Hydro-Québec's transmission operations from its generation and distribution.[106] A Transmission Provider Code of Conduct governs relations between HQT and other Hydro-Québec *unités d'affaires* and is intended to prevent preferential treatment or cross-subsidization.[107]
- HQT's *Direction principale – Contrôle des mouvements d'énergie et exploitation du réseau* ("DPCMEER") provides many services for the Québec Interconnection which would fall under the dispatch heading on FERC Form 1. DPCMEER has five divisions.
    - *La direction – contrôle des mouvements d'énergie* ("*DCMÉ*") balances loads and operates the main transmission network.
    - *La direction – exploitation du réseau* ("*DER*") comprises three divisions, two that operate regional networks and a third that supports the first 2 divisions.
    - *La direction – normes de fiabilité et conformité réglementaire* ("*DNFCR*") addresses transmission reliability standards and regulatory compliance.

  A Reliability Coordinator Code of Conduct discourages *DCMÉ* from providing preferential treatment to other Hydro-Québec business units.

[106] This move helped Hydro-Québec obtain a license to sell electricity at unregulated prices in U.S. bulk power markets.

[107] One reason that these arrangements matter is that independent generators and marketers also use HQT's system.

- Hydro-Québec's *Innovation, équipement et services partagés* division provides HQT with design and construction services.

- Miscellaneous services that HQT uses are provided by other Hydro-Québec divisions.

Accounting Idiosyncrasies

PEG expended a great deal of effort in this project, via information requests and document perusals, to learn about idiosyncrasies in HQT's accounting which should be addressed in the benchmarking study. The notable idiosyncrasies include the following.

- U.S. GAAP accounting has been used by the Company only since July 2015[108].

- HQT does not itemize its costs consistently with the FERC's Uniform System of Accounts or Form 1. Certain costs that PEG has excluded from past transmission cost studies using U.S. data nonetheless are itemized consistently by HQT for easy removal. These include costs of the retirement program (*régime de retraite*), other benefits (*autres avantages sociaux*), and transmission by others (*achats de service de transport*). However, HQT does not itemize certain costs that we removed from our productivity study and might wish to remove from the benchmarking study. These include costs of dispatching and miscellaneous transmission *CNE.*[109]

- HQT's status as a division of a vertically-integrated utility affects its cost accounting. Assets devoted chiefly to the provision of transmission service are deemed transmission assets and included in the transmission *base de tarification* (rate base). In addition to *postes* and *lignes*, these assets include land, buildings, and control centers. Since decision D-2008-019, these assets have also included most of Hydro-Québec's telecommunications assets.[110]

  The Company is billed for certain goods and services provided to it by other *unités d'affaires*. These charges are reported as *charges de services partagés*, a component of *CNE* in HQT's *revenus requis* summary tables. Included are charges for information,

[108] B-0265 (HQT-16, Document 1), response 1.9.

[109] In B-0265 (HQT-16, Document 1, response 4.1), HQT did report the *charges brutes directes* for the *DCMÉ* from 2015 to 2019.

[110] Ibid, *response* 1.4.

communications, purchasing, building, transportation, materials handling, and corporate services. These charges may include a return on the assets that Hydro-Québec has assigned to the supplying units. Also included in HQT's *revenus requis* are certain *frais corporatifs* for corporate service costs that are divided between business units using rules of thumb ("*règles d'imputation*").

- HQT in turn bills other *unités d'affaires* for services that it provides to them. Charges for many services HQT provides to other divisions are billed as *facturation interne émise.* Charges for costs of telecommunications assets are reported as *autres revenus de facturation interne.*
- Since any administrative and general expenses or costs of general plant which are assigned to HQT take the form of *coûts de services partagés* and *frais corporatifs*, we cannot assign to HQT a share of these costs using formulas as we do when calculating the (loaded) transmission costs of U.S. utilities.
- HQT reported in response 4.3 of B-0265 (HQT-16, document 1) that itemized costs of its telecommunications assets were not readily available and did not report these costs in a form that facilitated their removal.
- Data on the gross and net value of HQT's transmission plant and the value of its gross plant additions are readily available only since 2001.[111] These data make it possible to compute HQT's capital cost using a monetary approach such as geometric (or hyperbolic) decay. However, the benchmark year for these calculations is fairly recent. This reduces the accuracy of capital and total cost benchmarking, especially in the years before 2010.
- A change in HQT's accounting for the value of its asset retirements in 2009 which makes it difficult to compute its capital cost using the one-hoss shay method was noted above.[112]

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[111] Ibid, *response* 5.2.

[112] Ibid, *response* 5.3.

Benchmarking Details

Calculating HQT's Costs

Our calculation of HQT's cost has the following notable features.

- Capital cost was calculated using a geometric decay (monetary) specification, and was thus the product of consistent capital price and quantity indexes. In these calculations we considered the costs of tangible transmission plant in service (*immobilisations corporelles en exploitation*) but not the (much smaller) costs of intangible plant (*actifs incorporels*), regulatory assets (*actifs réglementaires*), government reimbursements (*remboursement gouvernemental*), working capital (*fonds de roulement*), or taxes. The capital quantity at the end of the first year calculated (2001) was the inflation-adjusted net plant value. Values of the capital quantity index in later years were calculated using inflation-adjusted data on the gross value of additions to tangible plant in service (*mises en exploitation*) less the value of *contributions internes et autres* and of reimbursements to independent power producers*.*

- *CNE* were computed using the formula

$$(Masse\ salariale - Avantages\ Sociaux + Autres\ Charges\ Directes + Charges\ de\ Services\ Partagés) * \left[1 - \frac{Coûts\ Capitalisés}{(\ Charges\ Brutes\ Directes + Charges\ de\ Services\ Partagés))}\right] + Frais\ Corporatifs\ - (Facturation\ Interne\ émise\ +\ Autres\ Revenus\ de\ Facturation\ Interne)$$

Note that we adjusted *coûts capitalisés* for the removal of *avantages sociaux.* Our *CNE* calculations did not include costs of electricity or transmission services that HQT purchased or adjustments for *compte d'écarts et de reports, interêt relié au remboursement gouvernemental,* or *facturation externe.*

Calculating U.S. Transmission Costs

The idiosyncrasies in HQT's data which we just discussed prompted us to calculate the *CNE* of U.S. utilities a little differently than we did in the productivity study. As in the productivity study, we excluded costs of transmission by others. We did *not* exclude dispatching expenses or miscellaneous transmission expenses because HQT did not consistently itemize these expenses. However, we did remove some companies from the sample which reported uncommonly large dispatching or miscellaneous transmission expenses which we suspect other companies would have reported as transmission by other expenses. All of the anomalies occurred during years when these companies were ISO members. This is the main reason for differences in the econometric and productivity samples.

Sample Period

We used our three econometric transmission cost models to benchmark the transmission costs of HQT during the years for which suitable data on its operations are available. We focused on the 2017-2019 period for several reasons.

- Due to data limitations, capital cost could not be calculated before 2001. When using a monetary method it is desirable to benchmark costs that are at least ten years older than the first year for which they are calculated.
- Consistent data on the *CNE* of HQT are only available starting in 2007.
- HQT has used U.S. GAAP accounting only since 2015.
- The recent years are more relevant for setting the stretch factor.
- We lack forecasts of future costs and business conditions which would permit us to benchmark such costs. However, this can in principle be done in HQT's next *demande tarifaire*.

How HQT Compares to Sampled U.S. Utilities

Table 7 compares the costs and business conditions of HQT to those of sampled U.S. utilities. Average values for HQT are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

- HQT's *CNE*, capital cost, and total cost (in Canadian dollars) were all about twelve times higher than the U.S. sample mean (in American dollars).[113]
- One of the reasons for the higher costs was that HQT's transmission line miles and ratcheted peak demand were both roughly five times higher than the mean.

[113] Capital cost differs from that which HQT uses in *dossiers tarifaires*.

Table 7

How HQT's Recent Costs and Business Conditions Compare to 2019 Sample Norms

Costs and Business Conditions		Units	HQT 2017	HQT 2018	HQT 2019	HQT Average 2017-2019 [A]	U.S. Sample Mean (2019) [B]	HQT Ave / 2019 Sample Mean [C=A/B]	ln (C)	Comments
Costs										
Total Cost	[D]	Canadian Dollars for HQT	3,740,586,670	3,921,977,277	3,720,385,075	3,794,316,341	304,469,798	12.46	2.52	
CNE	[E]	Canadian Dollars for HQT	703,823,300	773,058,813	756,724,251	744,535,455	64,162,086	11.60	2.45	
Capital Cost	[F]	Canadian Dollars for HQT	3,036,763,369	3,148,918,463	2,963,660,823	3,049,780,885	240,307,713	12.69	2.54	
Outputs										
Transmission Line Miles		Miles	21,256	21,183	21,457	21,299	3,969	5.37	1.68	
Ratcheted Peak Demand	[G]	MW	40,812	40,812	40,812	40,812	8,204	4.97	1.60	
Cost/MW										
Total Cost	[H=D/G]	Canadian Dollars for HQT	91,654	96,099	91,159	92,971	37,112	2.51	0.92	
CNE	[I=E/G]	Canadian Dollars for HQT	17,245	18,942	18,542	18,243	7,821	2.33	0.85	
Capital Cost	[J=F/G]	Canadian Dollars for HQT	74,409	77,157	72,617	74,728	29,291	2.55	0.94	
Input Prices										
Total Factor	[K]	Index Number	1.24	1.26	1.20	1.23	0.99	1.24	0.22	
CNE	[L]	Index Number	1.11	1.13	1.17	1.14	1.00	1.14	0.13	
Capital	[M]	Index Number	120	121	114	118	92.92	1.27	0.24	
Real Unit Cost										
Total Factor	[N=(D/K)/G]	Index Number	74,046	76,461	75,883	75,464	37,424	2.02	0.70	
CNE	[O=(E/L)/G]	Index Number	15,514	16,753	15,915	16,062	7,818	2.05	0.72	
Capital	[P=(F/M)/G]	Index Number	622	635	637	631	315	2.00	0.69	
Productivity (output = peak)										
Total Factor	[K/(D/G)]	Index Number	0.501	0.485	0.489	0.492	0.99	0.50	-0.70	
CNE	[L/(E/G)]	Index Number	0.504	0.467	0.491	0.487	1.00	0.49	-0.72	
Capital	[M/(F/G)]	Index Number	47.108	46.110	45.956	46.391	92.92	0.50	-0.69	
MVA per Substation		Ratio	449	452	457	453	371	1.23		Cost Disadvantage
Substations per Line Mile		Ratio	0.02	0.02	0.02	0.024	0.02	1.17		Cost Disadvantage
Percentage of Line Plant that is Overhead		Percent	0.95	0.95	0.95	95%	89%	1.07		Cost Advantage
Percentage of Plant that is Transmission		Percent	0.33	0.34	0.35	34%	21%	1.67		Cost Disadvantage
Percentage of Service Territory Forested		Percent	0.74	0.74	0.74	74%	61%	1.22		Cost Disadvantage
Construction Standards Index		N/A	0.87	0.87	0.87	0.87	0.68	1.28		Cost Disadvantage
Regional Transmission Organization (binary variable)		N/A	0.00	0.00	0.00	0.00	0.57	0.00		Cost Advantage

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- Simple unit cost comparisons can be obtained by dividing each of the three costs by ratcheted peak demand. It can be seen that all three unit costs are roughly 2.5 times the mean.
- Input prices are modestly higher for HQT than the U.S. sample.
- Real unit cost and productivity metrics have been computed, as discussed in Section 3.3, which take account of input price differences as well as differences in operating scale. It can be seen that HQT's real unit cost metrics were all roughly twice the mean. The CNE, capital, and total factor productivity of HQT are all roughly 50% of the mean.
- HQT faces an array of other business conditions that are in general less favorable than sample norms. For example, HQT must deal with higher forestation, MVA per substation, and substations per line mile, and construction standards. On the other hand, HQT is not an ISO member.

Econometric Benchmarking Results

Total Cost

We compared HQT's total cost thus calculated to the cost projected by our econometric total cost benchmarking model. From 2017-19, the three most recent years for which data are available, HQT's total cost was 67% above the benchmark value.[114] This is commensurate with a bottom quartile ranking for the U.S. sample.

Capital Cost

We compared HQT's capital cost to the cost projected by our econometric capital cost benchmarking model. From 2017 to 2019, HQT's capital cost exceeded the benchmarks by about 55% on average. This is commensurate with a bottom quartile ranking.

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[114] All percentages are calculated logarithmically.

CNE

We compared HQT's *CNE* to the cost projected by our econometric *CNE* benchmarking model. From 2017 to 2019, the *CNE* of HQT exceeded the benchmark by an extraordinary 121%. This is commensurate with a bottom quartile ranking in the U.S. sample.

Several possible reasons may be advanced for the poor *CNE* performance score of HQT in our research.

- Our *CNE* model does not have a high explanatory power.
- HQT is an extreme outlier with respect to the interaction term (Line length x Ratcheted Peak Demand), which has a negative and highly significant parameter estimate.
- HQT also has unusually large substation operations, and we have had a difficult time developing variables that measure the *CNE* challenge of substation operations and have high statistical significance.
- HQT has adopted a *modele de gestion d'actifs* which requires high *CNE* to prolong system age.
- HQT may have been assigned an unusually high share of Hydro-Québec's general costs.
- HQT incurs as *CNE* costs of general plant which, in our calculations for U.S. utilities, are treated as capital costs.
- The *CNE* of HQT may be noncomparable to those of U.S. utilities in ways that we don't understand despite numerous information requests.

6. Implications for *MRIs*

In this section of the report we consider the implications of our research for the X factor and S factor terms of HQT revenue cap indexes. In addition to the implications for the *CNE* revenue cap index, we consider the implications for a possible comprehensive revenue cap index in any succeeding *MRI*.

6.1. X Factors

The revenue cap index for HQT's current *MRI* applies to *CNE* revenue. The X factor should then be based on productivity trends in the use of *CNE* inputs (e.g., labor and materials). The Régie could base X on the **1.74%** annual decline in *CNE* productivity over the fifteen most recent years of the sample period or the **0.68%** decline over the full sample period. The decline in *CNE* productivity may be due in part to short-term circumstances such as the enforcement of new reliability standards. In this regard, it is notable that the decline in *CNE* productivity decline was especially pronounced from 2007 to 2010, shortly after passage of the EPAct. In the nine years from 2011 to 2019 *CNE* productivity growth has averaged a 0.57% decline, which is similar to that for the full-sample trend. PEG reported 0.83% average annual *growth* in the *CNE* productivity of Hydro One transmission in its recent *MRI* proceeding.[115] The Régie should also consider the 0% productivity growth target which Ontario regulators have chosen.

The Régie has also evinced interest in the X factor that might be applicable to a future comprehensive revenue cap index. Here again there are choices, which this time include a fifteen-year *PMF* decline of **2.26%**, a longer-term decline of **0.62%**, and the 0% target that the Ontario Energy Board chose. Recollecting our discussion in Section 2 of the special circumstances of U.S. transmitters in recent years, we lack the evidence at this time to conclude that the unusually negative *PMF* growth of U.S. transmitters will be applicable to HQT in the five years of any succeeding *MRI.*

The choice between such numbers would also depend on other aspects of the *MRI*. A more negative number would help HQT fund more capex. Capital revenue may in some years exceed HQT's capital cost. HQT should then have less need for extra revenue for capex surges.

[115] Mark Newton Lowry, *Incentive Regulation for Hydro One Transmission*, EB-2019-0082 Exhibit M1, September 2019 p. 36.

Our report has detailed several provisions for addressing this situation. One is to contain or eliminate eligibility for extra revenue. If supplemental revenue is nonetheless permitted, provisions like the following merit consideration.

- The X factor could be raised to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

6.2. Stretch Factors

Our econometric benchmarking research for AQCIE-CIFQ suggests that the stretch factor for the current *CNE* revenue cap index should be no less than **0.60%.** This is the stretch factor that would be chosen in Ontario based on a similar benchmarking score. Our current results suggest that the stretch factor for any future *comprehensive* revenue cap index would also be no less than **0.60%.** The Régie is, of course, under no obligation to base its stretch factors on the Ontario Energy Board's schedule.

The Régie may wish to update the benchmarking study in the year in which such an *MRI* is developed. A new study can consider forward test year costs that HQT proposes as well as additional years of historic costs. Alternatively, the models developed here could be used with minimal modification.

The Régie should increase the stretch factor to reflect the unusually weak performance incentives in the U.S. power transmission industry over the sample period. The incentive power of the proposed plan is not remarkably strong due to the comparatively short four-year term and the earnings sharing mechanism. However, we have seen that the incentive power of U.S. transmission regulation was significantly weakened by the FERC's use of ROE premia and formula rate plans.

Based on our incentive power research, we recommend a stretch factor adder of at least **0.1%** should the Régie base X on productivity results for the full sample period. An adder of at least **0.3%** is recommended if X is based on results for the most recent fifteen years.

Appendix A: Additional Information on Research Methods

A.1 Technical Details of PEG's Empirical Research

This section contains more technical details of our empirical research. We first discuss our input quantity and productivity indexes. 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 *CNE*, capital, and multifactor input quantity trend indexes. Each of these indexes has a chain-weighted Törnqvist form.[116] This means that its annual growth rate is determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad \text{[A1]}$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex value 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 natural logarithm of the ratio of the quantities in successive years. Calculations of the average shares of each input in the applicable cost of each utility in the current and prior years serve as weights.

[116] 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

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right). \qquad [A2]$$

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

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Section 3.4 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 previously processed by PEG permitted us to use 1964 as the initial year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of the (transmission or general) plant that it and any predecessor utilities reported. We estimated the quantities of capital in that year by dividing these values, respectively, by triangularized weighted averages of 47 consecutive values of a regional Handy Whitman Index of power transmission construction cost and 16 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. 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 geometric decay perpetual inventory equation was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad [A3]$$

Here, the parameter *d* is the (constant) economic depreciation rate and $VKA_{j,t}$ is the value of gross additions to utility plant. The assumed 47-year average service life for transmission plant, 16-year average service life for general plant, 1.65 declining balance rate for equipment, and 0.91 declining balance rate for structures were used to set *d*.

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

$$WKS_{j,t} = d \cdot WKA_{j,t} + r_t \cdot WKA_{j,t-1} + (WKA_{j,t} - WKA_{j,t-1}). \qquad [A4]$$

The first term corresponds to the cost of depreciation. The second term corresponds to the return on capital. The term in parentheses corresponds to capital gains.

A.2 Econometric Research Methods

This section of the Appendix 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:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad [A5]$$

Here, for each company *h* in year *t*, $C_{h,t}$ is cost, *L* is the length of transmission lines, and *D* is ratcheted peak demand. Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad [A6]$$

The double log model is so-called because right- and left-hand side variables in the equation are logged.[117] 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 length of transmission lines. Elasticity estimates are informative 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

[117] In other words, the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

the cost and business condition variables might assume. This feature 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:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \qquad [A7]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to a 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 $\ln L_{h,t} \cdot \ln D_{h,t}$ 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 a "flexible" functional form. Flexible forms can accommodate a greater variety of the possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, statistical theory suggests that 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. Most commonly, only output and any input price variables are translogged.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the second-order 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 in the cost model. The estimation procedure that is best known, ordinary least squares ("OLS"), is readily available in commercial econometric software. It has good statistical properties under simple assumptions about the structure of the data and the error terms. These assumptions are often violated by real world economic data.

A common problem in econometric cost research is autocorrelation of error terms. Autocorrelation, also known as serial correlation, occurs when data from one year are correlated to the data in subsequent years. This reduces the precision of parameter estimates and debases estimates of the error terms that are used in tests of the statistical significance of parameter estimates. This can complicate model development.

Several econometric methods have been developed to address autocorrelation. One class of estimators, called generalized least squares, adjusts the parameters using estimates of the autocorrelation pattern and improves the accuracy of the estimated standard errors. We have in past studies frequently used a generalized least squares estimator with an AR1 process in our research. Another class of estimators, called robust standard errors estimators, improves the accuracy of the estimated standard errors but uses OLS to estimate model parameters.

The choice between these approaches has been debated several times in recent Ontario Energy Board proceedings. To diffuse controversy in this proceeding, we have adopted in this study the general approach that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors available in the Stata statistical software package.

A.3 Details of PSE's Forestation and Construction Standards Variables

Forestation Variable

PSE has used its forestation variable in several power distribution benchmarking studies. It is inefficient to develop a variable of similar quality when its use in this proceeding can be purchased at a reasonable price from PSE. To save money we used the value for the forestation variable which PSE had assigned to Hydro One Networks in a distribution *MRI* proceeding.

Here is PSE's discussion of its forestation variable from a recent Ontario report. [118]

The **percentage of forestation** variable is based on GIS (geographic information system) land cover maps. PSE used the GlobCover 2009 product processed and produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation,

[118] Fenrick, Steve, Power System Engineering, "Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry," OEB Proceeding EB-2017-0049, Exhibit A-3-2, Attachment 1, November 4, 2016, p. 10.

the higher OM&A costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Hydro One.

Construction Standards Index

PSE developed its construction standards index for use in its Hydro One Transmission benchmarking study. To save money we used the value for the construction standards index which PSE had assigned to Hydro One Networks in that study.

Here is PSE's discussion of its construction standards index from a report in the recent Hydro One Transmission *MRI* proceeding. [119]

The **construction standards index (or loading)** variable measures the minimum requirements for strength of transmission structures, which vary by geographic region. Transmission lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware.

The loading variable is a way to quantify the expense associated with transmission line construction based on local weather conditions and the resultant regulatory requirements. This is accomplished by evaluating the percentage of strength capacity utilized under required load cases for a base transmission structure in different regions. The process and reasoning behind this variable are included in Appendix A. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

Here is the referenced discussion in the Appendix of that report.

This Appendix explains the theory and data behind the transmission loading variable discussed [above] (also known as the construction standards index). Per the Canadian Standards Association (CSA) and the National Electrical Safety Code (NESC), overhead transmission lines constructed throughout Ontario, Canada and the United States must withstand a minimum combination of accumulated ice and wind based on local extreme historical weather conditions. As a result, the required minimum design/build structural strength for an overhead transmission line is dependent on the physical location of the line.

This minimum structural strength requirement has a direct influence on the overall capital cost a utility must devote to its overhead transmission plant. For example, a transmission structure designed for harsher loading conditions is more expensive to construct because it may require larger diameter poles, greater setting or foundation depth, specialized insulators, and/or stronger hardware.

[119] Fenrick, Steve, and Sonju, Erik, Power System Engineering, "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," OEB Proceeding EB-2019-0082, Exhibit A-4-1, Attachment 1, January 24, 2019, pp. 28, 55-59.

Furthermore, since these minimum strength requirements are developed from documented historical weather conditions, they provide an indirect indication of the severity of extreme ice and wind storms that overhead transmission lines are exposed to, which can influence operational and maintenance costs.

To account for the influence of CSA and NESC minimum overhead transmission line structure strength requirements and associated extreme weather conditions as they relate to total cost benchmarking, Power System Engineering's transmission line design engineers developed a related variable for statistical analysis. This was accomplished by evaluating the percentage of utilized strength capacity, under required CSA and NESC load cases, for a base transmission structure in different zones.

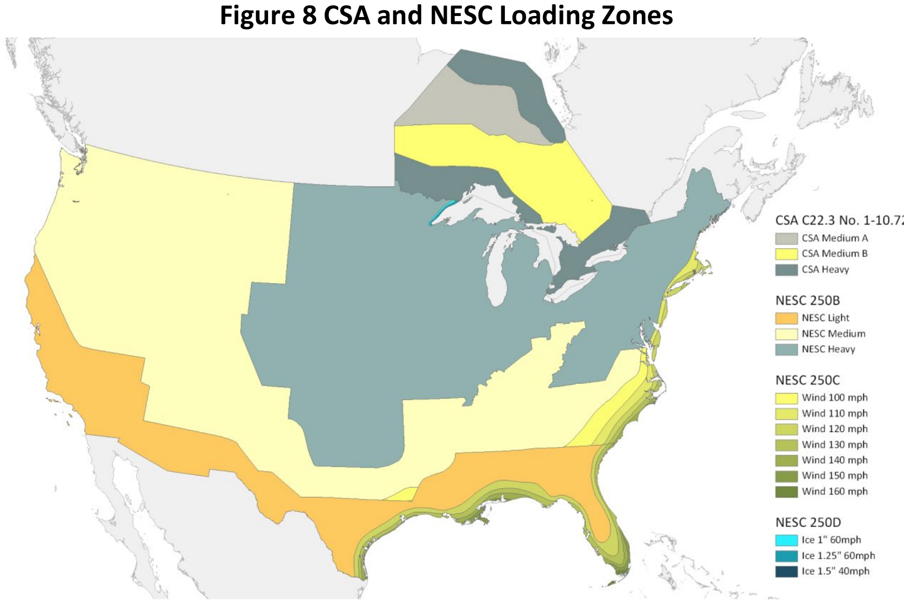
"Percentage of utilized strength capacity" is the percentage of the load resulting from specific design criteria (e.g., this line was designed to meet winds of X mph and ice of Y thickness) as a function of the overall maximum strength of the structure. The variable is a way to quantify the expense associated with transmission line construction based on local weather conditions. There were three main steps in developing the variable, as described below.

Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of transmission structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used. The zone boundaries and the required ice and wind load cases are outlined in the Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10 for Canada, and the National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure 8.

Figure 8 CSA and NESC Loading Zones



Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

2. Loading capacity was evaluated for a base structure in each zone.

A base transmission structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table 13. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

Thus, Table 14 represents the loads as a percentage of the maximum allowable for the base transmission structure. For example, the design criteria for CSA 7.2 zone "Medium A" is 73.3% of the maximum load strength of the base structure described in Table 13. The design criteria required for a structure in CSA 7.2 zone "Severe" is 148.9% of the maximum load strength of the base structure described in Table 13, indicating that the base transmission structure would fail in those conditions.

Industry best practice is to consider local historical weather data for transmission line designs, but the deterministic load cases defined by the CSA and NESC provide minimum requirements for each zone. Therefore, the load cases identified in CSA C22.3 No. 1-20 7.2 and NESC Rules 250B, 250C, and 250D were used for analysis. Loading zones with the same names in Canada and the United States are not equivalent, e.g. the CSA "Heavy" zone specifies different accumulated ice and wind loads than the NESC "Heavy" zone. Multipliers, including strength factors for structure components and load factors for ice and wind loads, are also specified in each code and were included in this analysis. PLS-CADD Lite, an engineering modeling software application for transmission and distribution structures, was used to complete nonlinear analysis of the base structure for each zonal load case, outlined in Table 14.

Table 13 Base Transmission Structure Specifications

	Metric		English	
Pole Material	wood			
Pole Length	22.9	m	75	ft
Pole Class	H2			
Span Length	106.7	m	350	ft
Framing	TP-115			
Voltage	115 kV			
Construction Grade	NESC Grade B / CSA Grade 1			
Transmission Conductor Material	795 (26/7) ACSR			
Transmission Design Tension	6000	lb	26.7	kN
Shield Wire Material	3/8" EHS Steel			
Shield Wire Design Tension	2700	lb	12.0	kN

Table 14 Loading Capacity Usage Percentages by Loading Zone

CSA 7.2	**Zone**		**Loading [%]**
	Medium A		73.3
	Medium B		81.5
	Heavy		103.5
	Severe		148.9
NESC 250B	**Zone**		**Loading [%]**
	Light		75.3
	Medium		49.7
	Heavy		66.2
NESC 250C	**Wind [mph]**		**Loading [%]**
	85		43.1
	90		48.2
	100		59.1
	110		71.1
	120		84.1
	130		98.1
	140		113.1
	150		128.9
	160		145.5
NESC 250D	**Ice [in]**	**Wind [mph]**	**Loading [%]**
	1.5	30	33.7
	0.75	40	29.2
	1	40	36.2
	1.25	40	44.3
	1.5	40	53.7
	0.5	50	34.7
	0.75	50	43.9
	1	50	54.1
	0.5	60	48.9
	0.75	60	61.7
	1	60	75.9
	1.25	60	91.7

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2
3. Nonlinear loading models: PLS-CADD Lite Version 15.00

4. GIS mapping software: ArcGIS Pro v2.1, ArcGIS Server 10.5, SQL Server 2014
5. Utility service territories: S&P Global – Platts and Power System Engineering acquired service territories <https://www.platts.com/maps-geospatial>

PLS-CADD Lite Model Inputs

Zonal weather criteria are defined in NESC 250B and CSA 22.3 No. 1-10 7.2 and summarized in Table 15 below. The NESC set includes two additional sets of load cases which do not have counterparts in the CSA. These are Rule 250C: extreme wind loading and Rule 250D: extreme ice with concurrent wind loading. Separate zones were identified for these rules as well.

Table 15 Weather Criteria

		Wire Ice Density		Air Density Factor		Wind Pressure		Wire Ice Thickness		Ambient Temp		NESC Constant	
		[kg/m^3]	[lbs/ft^3]	[Pa/(m/s)^2]	[psf/mph^2]	[Pa]	[psf]	[mm]	[in]	[°C]	[°F]	[N/m]	[lb/ft]
NESC	Heavy	913	57.0	0.613	0.00256	190.5	4	12.7	0.5	-17.8	0	4.38	0.3
	Medium					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
	Light					428.6	9	0.0	0	-1.1	30	0.73	0.05
	Warm Islands (<9000 ft)					428.6	9	0.0	0	10.0	50	0.73	0.05
	Warm Islands (>9000 ft)					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
CSA	Severe	900	56.2	0.613	0.00256	400	8.40	19.0	0.75	-20	-4	N/A	
	Heavy					400	8.40	12.5	0.49	-20	-4		
	Medium A					400	8.40	6.5	0.26	-20	-4		
	Medium B					300	6.30	12.5	0.49	-20	-4		

Load factors and strength factors are summarized in Tables 16 and 17, respectively.

Table 16 Load Factors

	NESC Grade B	CSA Grade 1
Vertical	1.50	4.00
Tansverse - wind	2.50	2.00
Transverse - wire tensions	1.65	2.00
Longitudinal - at deadends (with terminations or tension changes)	1.65	2.00
Longitudinal - general (without terminations or tension changes)	1.10	1.30

Table 17 Strength Factors

	NESC 250B Grade B	CSA Grade 1
Wood Structures	0.65	not specified - accounted for in load factors
Wood Crossarms & Braces	0.65	
Support Hardware	1.0	
Guy Wire	0.9	
Guy Anchor and Foundation	1.0	

Appendix B: 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 energy utility productivity trends on cost performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report 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 and benchmarking research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has also spoken at numerous conferences on utility regulation and statistical performance measurement. He recently coauthored two influential white papers on incentive regulation for Lawrence Berkeley National Laboratory. In the last five years, he has played a prominent role in incentive regulation proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Ontario as well as Québec. He holds a PhD in applied economics from the University of Wisconsin.

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