Total Factor Productivity and the X-factor for Hydro-Quebec TransÉnergie

PREPARED BY

Agustin J. Ros
Walter Graf
Sai Shetty
Maria Castaner

PREPARED FOR

Hydro-Quebec TransÉnergie

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Brattle

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I. Introduction

A. Background

In 2018, the Régie de l'énergie ("the Régie") adopted a *Mécanismes de Réglementation Incitative* ("MRI") that transitioned Hydro-Québec TransÉnergie ("HQT") away from traditional cost-of-service regulation by adopting a four-year MRI from 2019-2022 in the form of a revenue cap for HQT services.[1] The MRI constrains the growth of HQT's revenue requirement for allowable *charges nettes d'exploitation* (net operating expenses) based upon a revenue cap formula while capital expenses are under cost-of-service regulation. The revenue cap formula permits HQT's revenue requirement for net operating expenses to change in accordance with changes in *facteur d'inflation* (a Quebec-specific inflation factor), a f*acteur X* ("X-factor") and a *facteur de* croissance (an output factor based upon projected future output growth of HQT).

The Régie adopted an X-factor of 0.57% for HQT's net operating expenses based upon an analysis that examined the historical relationship between the growth in HQT's operating expenses and the growth in HQT's cost inflation—an analysis that is sometimes referred to as the "Kahn X-factor" methodology after the late academic and regulatory economist Alfred E. Kahn.[2] Under the current MRI, HQT is thus able to annually alter its revenue requirement applicable to net operating expenses by the change in *facteur d'inflation* minus 0.57% plus HQT's projected output growth rate. The Régie did not adopt a stretch factor—also known as the S-factor—as part of the MRI due to lack of evidence and left it to a future proceeding.[3]

Economic theory suggests that in a price or revenue cap formula, the X-factor represents the *industry-wide* total factor productivity growth ("TFP"), not the productivity of the regulated firm. TFP growth measures and compares a firm's output growth to its input growth and takes into account operations and maintenance ("O&M") and capital, thus the term "total" in TFP. In competitive markets, in the long run the growth in output prices is related to the growth in input prices *net of industry-wide* TFP growth and is consistent with the zero long run economic profit condition that characterizes competitive

[1] Régie D-2018-001 and D-2019-060.

[2] The U.S. Federal Energy Regulatory Commission ("FERC") uses the "Kahn X-factor" methodology for setting the maximum allowed tariffs for U.S. oil pipelines. The Kahn methodology derives the X-factor residually by comparing an economy-wide inflation measure—the Producer Price Index for Finished Goods ("PPI")—to the growth in oil pipeline costs. The FERC has been regulating U.S. oil pipeline tariffs under the Kahn X-factor methodology since 1995; see Revisions to Oil Pipeline Regulations Pursuant to Energy Policy Act of 1992, Order No. 561-A, July 28, 1994, Docket No. RM93-11-001, 18 CFR 341, 18 CFR 342, 18 CFR 343, 59 FR 40243.

[3] The stretch factor is an additional component in a revenue or price cap plan whose purpose is to provide to consumers the "first cut" of the economic benefits from adoption of MRI.

markets. Since the objective of regulation is to attempt to mimic outcomes in competitive markets, setting the X-factor based upon the *industry-wide* TFP is appropriate as it provides the correct incentives to reduce costs, operate efficiently and to earn a normal return in the long run.

The Régie, in D-2019-060, requested that HQT prepare *l'étude de productive multifactorielle* (multi-factor productivity or "MFP") in the first three years of the MRI which can be used potentially to reset the X-factor in year four of the plan or in a subsequent plan and that could apply to both HQT's operating expenses as well as its capital expenses.[4] In its decision, the Régie also requested a statistical benchmarking or econometric cost comparison study to assist in establishing the S-factor.

There is a large academic literature regarding TFP studies, and regulators in many jurisdictions and in several sectors—such as airports, electricity, natural gas, telecommunications and water—have experience conducting and adopting X-factors based upon such studies. TFP studies can differ in material ways, both in general methodology as well as in issues surrounding data sources, sample of companies used, and period of analysis—*i.e.*, short run vs. long run productivity estimates. For these reasons, in D-2019-060, the Régie adopted certain guidelines and principles for the TFP study. The guidelines included: using data from reliable and publicly available sources, having the study measure the growth of the overall productivity of the electricity transmission industry as opposed to measuring HQT productivity—with preference for the North American transmission industry—and including total costs in the TFP study, both capital inputs as well as O&M.

To comply with these and other Régie guidelines discussed below, The Brattle Group assembled a database of the costs, output and operating characteristics of U.S. electricity transmission companies using the FERC Form 1 data. Using the database and our TFP methodology, we developed a model that calculates a transmission industry TFP growth and X-factor for use in a MRI applicable for HQT's costs. We present results for TFP as well as partial factor productivity ("PFP") with respect to O&M and capital, as the Régie requested that the latter information be calculated and reported.

B. Summary of results

Our TFP model consists of 74 electricity transmission companies—some entirely vertically integrated, consisting of generation, transmission and distribution, and some transmission and distribution ("T&D") only. We developed output and input indices for each company and for each year over the period 1995 to 2019 and calculated annual TFP growth rates for each of the 74 electricity companies. Our output measure consists of a cost-weighted average of peak demand and total miles of transmission lines—with 60% weight given to peak demand and 40% given to miles of transmission lines. We calculate O&M

4 TFP and MFP studies are conceptually the same study when all of a firm's costs are included in the studies. We use the term TFP throughout the study unless required to distinguish between the two.

inputs that consist of separate input indices for labor, for materials, rents and services ("MR&S") and for capital based upon the *One-Hoss Shay* approach to capital services and capital prices.

Over the period 1995 to 2019, we find that the annual weighted average TFP growth—weighted based upon company size as measured by peak demand and kilometers of transmission lines—for the U.S. electricity transmission industry was -1.04 percent. In addition to an overall TFP, our analysis reveals that the PFP for capital inputs over the period was -0.05 percent and -3.38 percent for O&M. These are our *base case* results. We find that our results are sensitive to certain assumptions that we make, including the period used for the analysis, the methodology used for capital services—*i.e. One-Hoss Shay* vs. *Geometric Decay*—the asset life assumption, the output measure used and the inclusion or exclusion of common costs—*i.e.*, Administrative and General ("A&G") expenses and General Plant. As requested by the Régie, we provide sensitivity results for changes in each of these assumptions.

Our results suggest that if the Régie wishes to set the X-factor based upon industry-wide productivity, extend the MRI to include capital inputs as well as operating expenses and sets the inflation factor in the I-X formula to measure *input price* inflation then an X-factor of -1.04 percent is reasonable.[5] If the Régie wishes to maintain the current MRI focus only on operating expenses and set it to industry wide O&M PFP, our results suggest that an X-factor of -3.38 percent is the appropriate one.

With respect to the S-factor, as requested by the Régie, we obtained similar cost, output and operating characteristics data from HQT and used the U.S. and HQT data to conduct an econometric cost comparison analysis. We found that HQT's costs tended to be fairly close to the costs predicted by the econometric model. We caution, however, against mechanical use of econometric cost comparison analysis for setting the S-factor, as it cannot be a substitute for what we believe is ultimately an exercise based on regulatory judgement as well as regulatory precedence. For that reason, we also reviewed recent S-factor decisions in electricity transmission and electricity distribution revenue and price cap MRIs in jurisdictions in Canada and the U.S. and consider that evidence relevant and pertinent to the selection of an S-factor. Based upon our analysis, we believe that a range from 0.10 to 0.30 percent is a reasonable one for the S-factor for an MRI plan that resets the X-factor in year four of the plan or in a plan that could apply to both HQT's operating expenses as well as its capital expenses.

C. Outline of report

In this report, we provide a detailed description of our TFP and econometric cost comparison methodology, calculations and results. We begin in Section II by providing a background discussion on HQT, its operating and financial characteristics and its regulatory model over the years. We discuss the

[5] In Section VIII, we discuss the implications for the X-factor when the inflation factor in the I-X formula measures *output price* inflation, such as the economy-wide measure GDP-PI. In that case, the appropriate X-factor is the difference in total factor productivity growth between the regulated firm and the rest of the economy plus the difference in the growth rates of input prices between the rest of the economy and the regulated firm.

major structural and accounting changes that have occurred since the early 2000s and the impact this has on econometric cost comparison analysis. We also summarize the Régie MRI decisions that led to this proceeding and highlight the guidelines and principles that are to govern the TFP and econometric cost comparison studies in this proceeding.

In Section III, we discuss the economic principles of price and revenue cap regulation and the role of the X-factor in such plans. We begin by discussing the goals and objectives of MRIs and the incentive properties of such plans compared to rate-of-return regulation. We continue by deriving the X-factor in a price cap plan and implications when the MRI caps revenues instead of prices, as is the case for HQT's MRI. We end the section with a discussion on the theory and application of the S-factor and provide the S-factors adopted in some recent North American jurisdictions in electricity transmission and distribution MRI proceedings. We also discuss additional features of an MRI plan, such as the inflation, service quality and exogenous factors.

In Section IV, we provide a discussion on TFP methodology and describe our general approach in our TFP study. TFP growth measures and compares a firm's output growth to its input growth. A firm's input consists of different cost categories—labor, MR&S and capital—and TFP studies calculate an input index for each cost category and combines them into an individual input index by weighting the cost categories by their respective cost shares. The capital input is the input that is more challenging to measure and we discuss the different approaches to measuring the capital "services" that are embedded in a firm's capital stock as well as measuring the "price" of capital. Calculating an output index is typically more straightforward, although the unit of output selected can have a material impact on TFP growth.

In Section V, we describe our TFP model, the data we used, our data "cleaning" process and explain our company sample-selection process that led to a sample of 74 U.S. transmission companies in our TFP study. In Section VI, we present and describe our TFP study and results for our U.S. sample of transmission companies. We describe the construction of the output and input indices and the calculation of TFP growth over the period 1995 to 2019 as well as over other periods. As requested by the Régie, we provide capital and O&M partial factor productivity results. We also provide the reader with sensitivity analysis by altering key assumptions in the TFP model and gauging the impact on TFP growth.

In Section VII, we describe our econometric cost comparison analysis that compares HQT total real costs to the predicted total real costs from an econometric analysis and model involving the 74 U.S. transmission companies and HQT. We discuss the data used for our econometric analysis that includes the TFP data as well as additional data that controls for company-specific characteristics. We describe the model specification and estimator used to estimate the model parameters and present the results.

In Section VIII, we use the information in the previous sections to summarize the implications for the X-factor and present our recommendation regarding the X-factor and the S-factor for an MRI plan for HQT. Finally, in Appendix I, we provide information on the U.S. transmission companies we used in this study as well as the ones we did not use and the reasons why we did not use them, and in Appendix II, we present our biographies.

II. HQT Company and Regulatory Background

A. Company background

HQT is an operating division of Hydro-Quebec ("HQ"), one of the largest electric utilities in Canada.[6] HQT is responsible for developing HQ's power transmission system, providing transmission services and operating the system. HQT's transmission system is one of the most extensive in North America, comprising 34,802 kilometers of transmission lines, 534 substations, and interconnections that allow power interchanges with the grids in the Atlantic Provinces, Ontario and the U.S. Northeast.[7] Table 1 provides data on HQT financial and operational data.

TABLE 1: HQ AND HQT FINANCIAL AND OPERATIONAL DATA AS OF 2019

HQT Financials	
Revenue	$3.5 billion CAD
Net Income	$569 million CAD
Total Assets	$23.8 billion CAD
HQT Operational Data	
Length of Transmission Lines	34,802 km
Number of Substations	534
HQ Operational Data	
Net Electricity Sales	208.3 TWh (including 33.7 TWh in exports)
Capacity	36,700 MW

Source: HQ Annual Report 2019, available at: https://www.hydroquebec.com/data/documents-donnees/pdf/annual-report.pdf

HQT is required to offer open and non-discriminatory access to its system to all market participants, complying with Canadian and Quebec regulatory requirements as well as FERC requirements. HQT offers transmission services to its affiliate Hydro-Quebec Distribution ("HQD") for its native load and offers point-to-point services to Hydro-Quebec Production ("HQP") and third party customers. HQT also has tariffed services available for Network Integration Transmission Services. HQT is required to provide adequate transmission capacity to supply electricity to HQD and other electric customers, and to ensure the security and reliability of the transmission system.

6 The government of Quebec is the sole shareholder of HQ. In that role, the government may impose by decree on HQ or any of its divisions, obligations relating to investments, energy efficiency programs, and tariffs.

7 HQ Annual Report 2019, available at: https://www.hydroquebec.com/data/documents-donnees/pdf/annual-report.pdf.

HQ was a vertically integrated utility until 1997, at which time it created a new, separate division for its transmission services, HQT, in order to be able to sell power at market rates in the United States. In 2001, HQ was divided into two additional divisions: HQP, responsible for generating electricity and selling it into the wholesale power markets, and HQD, responsible for operating the distribution system and selling power to end-use customers. We provide a more detailed description of HQ and its operating segments in Table 2.

TABLE 2: HQ OPERATING SEGMENTS

Segment	Division Name	Description
Generation	Hydro-Quebec Production	• Operates and develops HQ's generation facilities • Generates electricity for the Quebec market and exports power to wholesale markets in the U.S. Northeast region
Transmission	Hydro-Quebec TransÉnergie	• Operates and develops HQ's power transmission system • Markets system capacity and manages power flows through Quebec
Distribution	Hydro-Quebec Distribution	• Operates and develops HQ's distribution system • Ensures the supply of electricity to the Quebec market • Manages activities related to electricity sales in Quebec, provides customer services, and promotes energy efficiency
Construction	Hydro-Quebec Innovation, Équipement et Services Partages	• Designs, builds and refurbishes generation and transmission facilities, mainly for HQ Production and HQ TransÉnergie
Other	Corporate and Other Activities	• Includes all corporate activities, including information and communication technologies, shared services, development, strategy, and research

Source: HQ Annual Report, p.44

The structural separation of HQ divisions realized from 1997 to 2001 resulted in the separation of most of the company's assets and the allocation of them to the different divisions. The divisions purchase some services from HQ's Corporate and Other Activities Division, such as shared services and corporate services. Shared services include: information and communication technologies such as IT support, IT development, telephony, mobile radios, network management; shared services center such as real estate, material management, air transport, food and accommodation, transportation services; and corporate units such as finance, corporate security, human resources, legal affairs, community relations.

Corporate costs are those costs incurred by corporate units to serve the interests of HQ as an entity instead of those of a specific division. These costs come from the following corporate units: Office of the Presidents (CEO, Chairman of the Board of Directors), ombudsman, internal audit, corporate affairs and general secretariat, communications and governmental affairs, and finance. HQ allocates corporate costs according to the method authorized by the Régie in D-2005-50. HQ allocates corporate fees amongst all HQ units, except for corporate units, based on primary operating expenses and net fixed assets, in equal parts. HQ allocates the corporate fees of the service units between business units based on their consumption of products and services subject to internal invoicing.

The Régie regulated HQT under a cost-of-service and rate-of-return methodology from 2001 to 2019. During this period, HQT submitted rate filings for approval by the Régie in 2001, 2005, 2007, and on an annual basis for all following years.[8] The rates are set using the projected revenue requirement and customer power demand. While transmission rates were updated in the rate cases through the years, the rate design has remain unchanged. The approved rate of return on capital during 2001-2007 ranged between 7.780%-9.723%, and from 2008-2016 it ranged between 6.497%-7.844%.

During this period, there have been several changes to HQT's structural operations and accounting methodology.[9] These include the following:

- *Acquisition of telecommunication assets in 2008*: In D-2008-019, the Régie authorized the acquisition of telecommunications assets, which resulted in a significant decrease in shared service charges and in return, an increase in depreciation, return on rate base and internal billing revenues issued for the portion not used by HQT.
- *End of regulatory practice relating to the retirement of capital assets in 2009*: HQT recorded retirement of capital assets in a separate account in property, plant and equipment (included in the rate base) for the years 2001 to 2004 and in regulatory assets (included in the rate base) for the years 2005 to 2009. HQT depreciated these assets at a rate of 3% over a maximum period of 10 years using the compound interest method. In 2009, HQT obtained authorization from the Régie to terminate this regulatory practice. The cost of all assets were written off as of December 31, 2009, with the exception of the amount related to the retirement of capital assets of substation Des Cantons, which was authorized by the Régie in 2010.
- *Retirement of capital assets of substation Des Cantons 2010*: As part of its 2010 rate case (R-3706-2009), HQT presented a technical assessment that justified the retirement of the substation. The Régie authorized the retirement in 2010 (D-2010-032).
- *Change in depreciation method*: From 2001 to 2009, HQT depreciated property, plant and equipment using the compound interest method at the rate of 3%, with the exception of construction, operating and research equipment, which HQT depreciated using the straight-line method. Starting in 2010, HQT depreciated property, plant and equipment using the straight-line method following the Régie's authorization in D-2010-020.
- *Transition to IFRS 2012 standards:* In 2011, HQT filed a request with the Régie to modify certain accounting methods resulting from the transition to the International Financial Reporting Standards (IFRS) in 2012. The Régie authorized the request in D-2012-021.
- *Transition to US GAAP accounting standards in 2015*: In 2015, HQT filed a request with the Régie to transition to the Generally Accepted Accounting Principles in the United States (US GAAP).

[8] Information provided to us by HQT.

[9] We discuss the implications of these operational and accounting changes for econometric cost comparison analysis in Section VII.

HQT requested deferral and variance accounts ("DVA"), outside the rate base, in order to account for the differences, other than pension costs, observed between the revenue requirement for 2015, established according to the proposed accounting methods, and those authorized in 2015.

- *Costs related to the project involving the replacement of PK type network circuit breakers for 2016 and 2017*: In 2016, HQT considered that all PK model circuit breakers in service on the transmission network were at risk and that they had to replace all of them as a matter of urgency in 2016 and 2017. In D-2016-077 and D-2016-174, the Régie authorized the creation of deferral and variance accounts (DVA), outside the rate base and bearing interest, to account for the costs related to the replacement of PK model circuit breakers.
- *Amendments to "ASC 715 Compensation - Retirement Benefits" in 2017*: In 2017, HQT filed a request to change the accounting policies of "ASC 715 Compensation - Retirement Benefits" and to create a deferral and variance accounts (DVA). The Régie authorized the request in D-2017-125. HQT carried out the disposal of the balance in the years 2018 and 2019.
- *Project write-off of CS23 compensator*: In 2019, HQT filed a request with the Régie to create a deferral and variance account (DVA), outside the rate base and bearing interest, to record all of the costs from the abandonment of work related to the CS23 compensator. The Régie authorized the DVA in D-2019-100 and the disposition of the balance of the DVA to be collected in the 2020 tariff year.

While HQT has been regulated under a cost-of-service and rate-of-return methodology from 2001 to 2018, from 2019 to 2022 HQT is operating under an MRI, which applies to O&M expenses only and with 2019 tariffs based upon cost of service. The MRI continues to regulate capital expenditures under cost of service. The next section summarizes the key aspects of the MRI.

B. The Régie and MRIs

In this section of our report, we provide a summary of the Régie's decisions on the HQT MRI and this proceeding that provides the general guidelines and principles. In the first sub-section below, we summarize the main features of HQT's current MRI where the X-factor applies only to certain O&M expenses, as contained in D-2018-001[10] and D-2019-060[11]. We continue and summarize the main principles and guidelines for this proceeding as contained in D-2020-028[12].

[10] Régie de l'énergie, D-2018-001, R-3897-2014, January 5, 2018, Phase 1, ("D-2018-001").

[11] Régie de l'énergie, D-2019-060, R-4058-2018, May 16, 2019, ("D-2019-060").

[12] Régie de l'énergie, D-2020-028, R-4058-2018, Phase 2, March 6, 2020, ("D-2020-028").

1. D-2018-001 & D-2019-060

In D-2018-001 and D-2019-060, the Régie established the key provisions of an MRI for HQT's transmission services. D-2018-001 provided a discussion of the general characteristics and the main components of the MRI for HQT. In D-2019-060, the Régie adopted an X-factor for HQT's O&M. These decisions embarked HQT on a transition away from regulating its tariffs and revenues under cost-of-service regulation, which it had been under since its inception in the early 2000s. In this sub-section, we discuss the main elements of these decisions.

In D-2018-001, the Régie adopted a four-year revenue cap MRI plan for HQT for the years 2019 to 2022, with the first-year rates based upon cost-of-service and the remaining three years to be based upon the application of the MRI indexation mechanism. The main characteristics and elements of the MRI that HQT operates under is contained in Decision D-2018-001.[13] The main elements of discussion in D-2018-001 consisted of the type of MRI to adopt, which HQT costs to include in the MRI, and the indexation formula to adopt and its main components—such as the inflation factor, the X-factor, the growth factor, and the types of costs to consider as being exogenous.

The Régie adopted the following revenue cap formula:[14]

$$RR_{t+1} = \left[(RR_t - Y_t - Z_t) \times (1 + I_t - (X + S))\right] + C_{t+1} + Y_{t+1} + Z_{t+1} + ER_{t-1} \quad (1)$$

where:

RR = revenue requirement (revenus requis ($))

Y = exclusions (*exclusions* ($))

Z = exogenous factor (*éléments exogènes* ($))

I = inflation (%)

X = productivity (*productivité* (%))

S = stretch factor (*dividende client* (%))

C = growth factor (*croissance des activités*)

ER = earnings sharing mechanism (*écarts de rendement* ($).)

The inflation factor selected was an index combining the CPI-Québec and the average growth rate of the weekly earnings of Québec employees. For the first three years of the plan, the X-factor was to be based upon judgement exercised by the Régie and the fourth year depending on the results of a productivity study.[15] Specifically, the Régie ordered HQT to carry out a TFP study during the first three years of the MRI plan and to submit the results during the third year for a possible application of the result during

13 For a discussion of the main elements of the MRI plan, see, D-2018-001 Table 2, p. 83.

14 D-2018-001 p. 84.

15 As discussed below, subsequent to D-2018-001, the Régie adopted an X-factor of 0.57% in D-2019-060.

the last year.[16] The growth factor (the C-factor) adopted by the Régie consists of the growth underlying HQT's investment plans and the related growth in net operating expenses.[17]

For the first three years, HQT costs regulated under the MRI plan include O&M expenses and do not include most capital expenses, which continue under a cost-of-service regulation. Specifically, the costs that are regulated under the MRI include net operating expenses (*charges nettes d'exploitation*), and other costs including taxes, purchase of transmission services (*achats de services de transport*), corporate fees, and interest related to government reimbursement (*intérêts reliés au remboursement gouvernemental)*.[18] Retirement costs were to be included in the costs covered by the MRI but the Régie ultimately dropped them from the plan.[19]

In D-2019-060, the Régie adopted an X-factor of 0.57% for use in years two through four of the MRI plan. The Régie adopted the "Kahn methodology" for the X-factor used by the U.S. FERC to regulate the tariffs of U.S. oil pipelines.[20] The Kahn methodology is also referred to by some as the "indirect or implicit" productivity method, because it calculates the productivity of a company residually by comparing the inflation and cost growth rates as opposed to measuring productivity directly using output and input indices.

HQT's expert in the proceeding calculated the difference between the growth rate of HQT costs that are governed under the MRI—*i.e.*, the operating expenses (*charges nettes d'exploitation*) and inflation over the period 2009 to 2017. The X-factor of 0.57% adopted by the Régie reflected the average over the entire period as opposed to a shorter period.[21] With respect to the S-factor, the Régie abstained from adopting one in its Decision D-2019-060. The reasons given by the Régie was lack of a study allowing it to assess HQT's comparative efficiency.[22]

2. Current proceeding D-2020-028

For this proceeding, the Régie established the principles and guidelines in D-2020-028. In this section, we highlight the main principles and guidelines and provide a summary of how our study comports with them.

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16 D-2018-001, ¶ 111.

17 D-2018-001, pp. 73-77.

18 D-2018-001, Table 2, p. 83.

19 D-2018-001, ¶ 117.

20 FERC *op. cit.* 2.

21 D-2019-060 ¶ 145.

22 D-2019-060 ¶ 151.

General Guidelines

- *The TFP study should be carried out in a transparent manner, based on data from reliable and publicly available sources*.[23] We utilize the U.S. FERC publicly available uniform system of accounts for our TFP and econometric cost comparison studies as well as other publicly available and reliable data sources.

- *The TFP study must be applicable to the Transmission Provider and be used to measure the growth of the overall productivity of the electricity transmission industry and gives preference to the electricity transmission industry in North America*.[24] We utilize data from 74 U.S. electricity transmission providers for the TFP study and calculate the overall productivity growth of the electricity transmission industry.

- *The TFP study must be accompanied by a statistical benchmarking, or econometric cost comparison, to establish an S-Factor.* We use the data from our TFP study combined with the HQT data to conduct an econometric cost comparison analysis. We also highlight S-factor decisions in recent electricity transmission and distribution price and revenue cap proceedings.

- *The detailed results of the calculations underlying the studies must be filed in a spreadsheet and be sufficiently documented to allow the Régie and stakeholders to understand them, validate them and, if necessary, reproduce them*.[25] We constructed our TFP model using Excel, which contains all our underlying data with all live formulas to permit a user to understand, validate and reproduce the results. We conducted our econometric cost comparison analysis using the data and econometric software program called R, with all the code documented for a user to replicate our results.

- *All the assumptions, methodological choices and the calibration of the models, inputs, outputs and calculations must be documented and presented in order to understand the impact of using an assumption, a methodological choice, an input, an output or a calculation that can significantly vary the results*.[26] In Sections IV and V of our report, we describe our TFP methodology such as the methodology we use for measuring capital services—*One-Hoss-Shay*—the measure of output that we use, the asset life assumption to name a few and the inclusion or

[23] D-2020-028 ¶ 92. It continues by stating that the experts may use confidential data from reliable and generally recognized sources, provided that they agree to make them available to other participants, so that they can consult or use them for the purposes of PMF studies and statistical studies and provided that an appropriate confidentiality agreement is concluded.

[24] D-2020-028 ¶ 92. It continues by stating that the experts can integrate electricity carriers from other countries, if they provide adequate justification for their use and can resort to an alternative industry, such as transportation of natural gas or petroleum products, if they demonstrate that the cost growth factors of this alternative industry are comparable to those of electricity transmission in North America.

[25] D-2020-28 ¶ 92.

[26] D-2020-28 ¶ 92.

exclusion of common costs. Our Excel model contains user inputs to permit the user to alter these assumptions and ascertain the impact on results.

Capital Expenditures

- *The Régie asks the experts to produce a PMF study that takes capital expenditure into account and should inform the following questions: (i) the productivity growth of electricity carriers in relation to capital expenditure; (ii) statistical comparison of the Transmission Provider's capital expenditure; (iii) sensitivity analyzes in order to understand the impact of using an assumption, a methodological choice, an input, an output or a calculation that can significantly vary the results; and (iv) the pros and cons of incorporating capital expenditures into the cost escalation formula and how best to do it*.[27] As requested, our TFP study provides partial factor productivity results for O&M and capital. We also do, as requested, an econometric cost comparison for HQT's total costs as well as its capital and O&M costs and we provide a discussion on the pros and cons of incorporating capital expenditures into the cost escalation formula in Section VIII of our report.

Specific Guidelines

- *The time horizon must be at least 15 years and allow the long-term growth of the industry to be measured and should be long enough to smooth out variations that could distort the measurement of long-term productivity growth in the power transmission industry or an alternative industry*.[28] Our TFP model measures TFP growth from 1994 to 2019, a period of twenty-five years and we provide TFP growth results for each year as well as for different periods.

- *The sample of firms used in the TFP study should be sufficient and diverse and should be adequate to measure the growth in overall productivity of the power transmission industry*.[29] We use a large and diverse sample of 74 U.S. transmission companies in our TFP and econometric cost benchmarking exercise, with the ability to select, if so desired, a different set of companies. In Section V, we discuss in detail our guiding principles behind our sample selection process.

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27 D-2020-28 ¶ 96.

28 D-2020-28 ¶ 106. It continues by stating that the experts should provide the rationale for the chosen horizon to adequately measure growth in long-term O&M and capital productivity. All the years of the chosen horizon should be used in order to calculate the results. However, experts may choose a time horizon shorter than 15 years for the purpose of their X-Factor recommendations. Moreover, experts must produce sensitivity analyzes with regard to the X-Factor by subtracting from the chosen horizon the years that significantly influence its value.

29 D-2020-28 ¶ 113. It continues by stating that all the companies in the sample should be used to calculate the results, while maintaining the option for the purposes of the X-Factor recommendation to choose a subset of carriers and to produce sensitivity analyzes with regard to the X-Factor by subtracting from the sample carriers or companies that significantly influence its value.

- *The experts should use the costs and indexing formulas consistent with the costs and the indexing formula taken into account in the Transmission Provider's MRI*.[30] In Section VI, we discuss the transmission costs that are included in our TFP study and in Section VIII, we discuss the current MRI indexing formula and its implications for an X-factor.

- *The experts can propose "adjustment factors", such as Input-Price Differential, Productivity Differential, Productivity Gap and Adjustments for exclusion of capital expenditures*.[31] In Section III, we provide a discussion of the relevance of the productivity and input-price differential in the derivation of the X-factor and when it is required and in Section VIII, we provide X-factor results when these productivity and input price differentials are necessary.

30 D-2020-28 ¶ 121.

31 D-2020-28 ¶ 127.

III. Economic Principles of Price and Revenue Caps and the X-factor

A. Primer on performance-based regulation

Incentive regulation, also known as "performance-based regulation" ("PBR"), is a mechanism for directly regulating the prices or revenues of public utilities, rather than profits, with the goal to improve the incentives for achieving efficiencies and cost savings. It is a replacement framework for cost-of-service regulation, which provides inferior incentives for achieving efficiencies and cost savings compared to PBR.

PBR commonly relies on benchmarking the allowable price (or revenue) increases for a given utility to the performance of a comparable group of utilities, such as the productivity of a comparable group of utilities. A typical PBR plan rewards a utility that is highly productive relative to the comparison group through higher profits, thus providing stronger incentives to achieve cost efficiencies than under-cost-of service regulation. In contrast, a typical PBR plan penalizes a utility that is less productive relative to the comparison group through lower profits, thus providing stronger incentives to improve performance than under cost-of-service regulation.

The central idea of PBR is to rely on incentives to increase efficiency while reducing regulatory costs to produce just and reasonable rates. In particular, PBR can help to improve two types of efficiencies:[32]

Productive efficiency: Taking customer demand as given, meeting that demand at least cost as possible and operating as close as possible to the frontier of the "production possibility set"; and

Allocative efficiency: Considering that customer demand for outputs and services can change based on their price, providing the highest value range of outputs and services, given the least-cost mix of current inputs and future cost structure and technology.

Depending on the type of PBR plan, the main reason why PBR increases productive efficiencies is it breaks the link between a company's actual costs and the prices it can charge customers. In general, productive efficiencies tend to be lower under cost-of-service regulation due to weaker incentives to reduce costs and increase efficiency. Several elements of PBR tend to bring about increased incentives to lower costs and improve performance. First, cost-of-service regulation is a "cost-plus" form of regulation whereby a firm's prices are linked to its underlying costs. An increase in prudently allowed

[32] To the extent that it provides more flexibility to introduce new services and/or more attractive rate plans, PBR can also increase dynamic efficiencies.

costs results in higher prices. This results in lower incentives to minimize costs.[33] PBR can reduce the link between realized costs and allowed rates. If a utility can find ways to meet demand while reducing costs, thereby increasing efficiency, it will keep some or all of the cost savings as additional profit. Thus, firms operating under a PBR plan have the incentive to do so. In contrast, a utility under cost-of-service regulation is required to lower revenues if it lowered its costs. In fact, if the efficiency improvement relates to capital, its profits may go down, as the firm may have less capital (rate base) to earn a rate-of-return. Second, PBR helps reduce the "Averch-Johnson effect" of utilities potentially "over-investing" in capital to increase the regulated rate base and thus the allowed profits under cost-of-service regulation.[34]

The potential for superior efficiency incentives and regulatory cost savings depends in part on the duration of a PBR plan. Typically, PBR plans can last anywhere from as little as two years to as long as ten years, often accompanied by a number of different PBR "tools" and "mechanisms". For example, regulators can cap the *prices* at which utilities sell their services and permit the firm to maximize its profits, contingent on meeting the price cap. The price cap can be a strict cap without any additional constraints, or alternatively adjusted with an "earnings sharing" mechanism, in which the utility returns some share of outsized earnings with customers—through lower prices, refunds, *etc*.—when earnings are above some threshold level. Regulators can choose to cap *revenues* instead of prices, as the Régie has done. There are several implementation alternatives for each of these approaches. For example, less formal PBR frameworks may only target some aspects of the utility's costs—*e.g.*, certain O&M expenses or certain capital expenses—while regulating other costs through more traditional means.

In addition to a PBR plan's duration, a key aspect that help determine the strength of the incentive effects include whether the plan incorporates an earnings share mechanism. In general, the longer the duration of the PBR plan, the greater the magnitude of the incentive effect as the firm has greater incentives to implement longer-term efficiency plans and to keep economic surpluses generated for longer periods. A PBR plan without earnings sharing provides greater incentive effects than plans with earnings sharing, which is effectively a tax on the incremental profits subject to sharing.

There are other potential advantages of PBR. For both the regulator and utility, PBR can help to reduce the high regulatory and administrative costs and burdens of annual or periodic rate cases. In addition, the utility may enjoy being able to exceed the allowed return on equity under PBR if they are able to operate more efficiently than expected. Finally, customers are likely to benefit from lower rates *than would otherwise have been the case*, as well as increased rate stability and predictability over that expected under cost-of-service regulation.

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[33] Cost-of-service regulation can provide incentives for reducing costs and increasing productive efficiency when rate case proceedings are infrequent—*i.e.*, through regulatory lag. A firm has an incentive to reduce costs between rate cases because it retains the benefits until the next rate cases. The longer the time between rate cases, the greater the incentive effects.

[34] Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-1069.

A potential drawback of PBR approach is that it is possible that the utility endeavors to lower costs at the expense of service quality. Thus, PBR may lead to decreased service quality. Regulators can address this through additional price or revenue adjustments to reflect service quality such as establishing service quality factors.

B. Price cap regulation and derivation of the X-factor

A primary goal of economic regulation is to regulate in a manner such that economic outcomes mimic the outcomes that one would observe under competition. In competitive markets, economic profits tend to zero in the long run. This is the starting point for price cap regulation. The long run zero profit condition under competition implies that average output price equals the cost the firm pays for the inputs needed to produce a unit of that good or service, accounting for the firms' productivity—that is, the efficiency of turning inputs into outputs.

Starting from that basic assumption, the cap used in price cap regulation is calculated to reflect what we would expect to observe in competitive markets in the long run: prices are set to equal input prices minus productivity "I-X", where I represents inflation and X represents industry-wide productivity. The "I – X" formula means that average prices for capped goods/services are adjusted for inflation (I), less the expected productivity growth over the relevant term, typically representative of an industry average (X). In essence, the allowed price changes mimic changes in average unit costs. In competitive markets, both I and X are external and outside the control of the firm. Thus, the price cap formula for the regulated firm—"I" and "X"—should likewise be external and exogenous to the regulated firm.

We present the mathematical derivation of the price cap index and the X-factor formulation following Bernstein, Hernandez, Rodriguez and Ros. (2006).[35] We start with the assumption discussed above, that economic profits are zero, so revenues equal costs. For a generalized firm with *n* outputs and *m* inputs, with p_i and q_i denoting the price and quantities of the *i*th output, and *wj* and *vj* the price and quantity of the *j*th input, we can write:

$$0 = R - C = \sum_{i=1}^{n} p_i q_i - \sum_{j=1}^{m} w_j v_j \qquad (2)$$

Totally differentiating the expression above yields the following:

[35] Jeffrey I. Bernstein, Juan Hernandez, Jose Maria Rodriguez, and Agustin J. Ros, "X-Factor updating and total factor productivity growth: the case of Peruvian telecommunications, 1996–2003," *Journal of Regulatory Economics* (2006) 30:316–342. This study builds upon the work of Jeffrey I. Bernstein and David M. Sappington, "Setting the X-Factor in Price Cap Regulation Plans," *Journal of Regulatory Economics* (1999) 16:5-26.

$$0 = \sum_{i=1}^{n} p_i q_i \frac{dq_i}{q_i} + \sum_{i=1}^{n} p_i q_i \frac{dp_i}{p_i} - \sum_{j=1}^{m} w_j v_j \frac{dv_j}{v_j} - \sum_{j=1}^{m} w_j v_j \frac{dw_j}{w_j} \qquad (3)$$

Next, we make the following definitions, with a dot over a variable *x* representing *dx/x* (a small percentage change):

$r_i = p_i q_i / R$ is the revenues share of the *i*th output

$s_j = w_j v_j / C$ is the cost share of the *j*th input

$$\dot{P} = \sum_{i=1}^{n} r_i \dot{p}_i \qquad (4)$$

$$\dot{W} = \sum_{j=1}^{m} s_j \dot{w}_j \qquad (5)$$

$$\dot{Q} = \sum_{i=1}^{n} r_i \dot{q}_i \qquad (6)$$

$$\dot{V} = \sum_{j=1}^{m} s_j \dot{v}_j \qquad (7)$$

Substituting into equation (3) above and rearranging yields:

$$\dot{P} = \dot{W} - (\dot{Q} - \dot{V}) \qquad (8)$$

We note that $\dot{T} = \dot{Q} - \dot{V}$ is the regulated firm's total factor productivity (TFP) growth rate, that is, the growth of the outputs less the growth of its inputs. This yields:

$$\dot{P} = \dot{W} - \dot{T} \qquad (9)$$

Equation (9) states that if a regulated firm's prices are set initially to ensure zero extranormal profit, and if the firm's prices are subsequently required to change at a rate equal to the difference between its input price growth rate and its productivity growth rate, then the regulated firm will continue to earn zero extranormal profit.

If price cap regulation were to proceed, however, by measuring actual changes in the regulated firm's input prices and productivity, and then by adjusting the firm's output prices accordingly, price cap regulation would function much like rate-of-return regulation. Therefore, it is common practice to set $\dot{T}$ in equation (9) based upon *industry-wide* TFP, rather than the TPF of the firm. It is also common practice to use a measure of input price inflation that is projected to prevail during the forthcoming price cap period and to base it on variables that are regularly updated. Accordingly, if the plan includes an inflation index designed to capture the expected changes in $\dot{W}$, then the productivity factor in that plan (X) would be $\dot{T}$, *industry-wide* TFP.[36]

Alternatively, when a plan uses an *output* inflation measure, such as economy-wide GDP-PI, the X-factor needs to account for differences between economy-wide and industry-wide TFP and input price changes. To see how, we observe that the relationship in equation (9) above is true for both the regulated firm in question, as well as the outside economy—as long as economic profits are still zero—and we can also write:

$$\dot{P}^E = \dot{W}^E - \dot{T}^E \tag{10}$$

With the superscript *E* referring to the outside economy. Taking the difference between the firm-specific and economy-wide expressions and rearranging, we see:

$$\dot{P} = \dot{P}^E - \left[\left(\dot{W}^E - \dot{W}\right) + (\dot{T} - \dot{T}^E)\right] \tag{11}$$

Labeling the terms in the square brackets as *X*, this yields:

$$\dot{P} = \dot{P}^E - X \tag{12}$$

This expression provides the basic formulation of the price cap regulation when the inflation factor is an economy-wide measure of inflation. It implies that regulated prices should be allowed to rise, "on average, at a rate equal to the rate of the output price inflation ($\dot{P}^E$) less an offset (X)."[37] This offset is the sum of "the difference in input price growth rates between the rest of the economy and the regulated firm ($\dot{W}^E - \dot{W}$)" and "the difference in total factor productivity growth rates between the regulated firm and the rest of the economy ($\dot{T} - \dot{T}^E$)."[38] The output price inflation is usually simplified to "*I*," yielding the familiar "*I – X*."

To summarize, when the inflation factor (I) in a price-cap plan is one that measures the input price inflation, then the X-factor is the *industry-wide* TFP. When an economy-wide output price inflation—such as GDP-PI—is the inflation factor (I) in a price cap plan, the X-factor is the industry-wide TFP differential—between the industry and the economy—plus the industry-wide input price differential.

C. Implications for revenue cap regulation

The incentive-based regime adopted by the Régie is to regulate the *revenues* of HQT, not *prices*, so we must make the link between the price cap formula derived in the section immediately preceding and an

36 Exclusive of a possible stretch factor.

37 *Ibid.* p. 329.

38 *Ibid.* p.328.

equivalent revenue cap. The revenue cap formula is the same as for price cap, with the exception that in addition to the X-factor, the formula contains an additional output growth factor, which is the expected growth rate of outputs. Logically, if the regulator limits revenues instead of prices, the revenue cap should include an output growth factor. If this growth factor were not included, the revenue formula could unfairly penalize—or reward—the firm.[39]

We derive this based on the derivation above, noting that the definitions imply that the revenue growth rate is simply the sum of the output price growth and the output quantity growth:

$$\dot{R} = \dot{P} + \dot{Q} \tag{13}$$

Substituting the expression derived above for the price cap regulation yields the revenue cap formula:

$$\dot{R} = \dot{P}^E - X + \dot{Q} \tag{14}$$

Revenues are permitted to grow at the rate of inflation ($\dot{P}^E$) minus the X-Factor plus the output quantity growth rate.

D. The consumer stretch factor

1. Background and theory

The consumer stretch factor—also known as the consumer productivity dividend—is a feature in some price and revenue cap plans adopted by regulators in electricity, gas and telecommunications. In its first price cap proceeding for electricity and gas distribution companies in 2012, the Alberta Utilities Commission described the purpose of a stretch factor:

> The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.[40]

In a 2017 decision, the Massachusetts Department of Public Utilities ("Mass DPU") also described the stretch factor as intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to incentive regulation.[41]

[39] Specifically, demand growth results in revenue growth even when prices remain constant. Without adjusting for output growth, a revenue cap formula would require the firm to lower its revenues—by lowering prices or lowering output—something contrary to outcomes in competitive markets.

[40] Alberta Utilities Commission Decision 2012-237, p. 100.

[41] D.P.U. 17-05, Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, November 30, 2017 ("Massachusetts DPU 17-05"), p. 394.

In an early PBR plan, the Ontario Energy Board stated the following about the stretch factor:

> It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the utility.[42]

In terms of how to estimate the stretch factor, the Alberta Utilities Commission stated:

> As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a —definitive analytical source like the TFP study represents.[43]

This was a sentiment echoed by the Mass DPU. In its 2017 decision, it summarized the position of NSTAR electric indicating that the determination of a consumer dividend is largely subjective and that there is a lack of quantitative, empirical basis for establishing its magnitude.[44]

While the Ontario Energy Board has adopted a quantitative approach to setting the stretch factor, as discussed further below, it has also emphasized the importance of judgement to assist in setting the stretch factor:

> The Board notes that all of the participants in the consultation agreed that the setting of stretch factors is a matter that calls for the exercise of judgement. As such, there are no hard and fast principles to guide the Board's determination of an appropriate value. The Board also notes that each of the participants urged the Board to take a conservative approach with respect to the stretch factor values in light of the fact that the Board's experience with benchmarking is in its early stages.[45]

The quantitative approach for the stretch factor that the Ontario Energy Board uses has evolved somewhat over time. In a 2013 report, as part of its fourth generation incentive regulation mechanism, the Board employed an econometric benchmarking approach to judge cost performance of distribution companies and laid out a range of relative cost performance on which to base the stretch factor.[46] As per this approach, companies are in one of five groups with associated stretch factors. The existence of

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42 Ontario Energy Board, EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," September 17, 2008. p.19.

43 Alberta Utilities Commission Decision 2012-237, p. 104.

44 Massachusetts DPU 17-05, p. 395.

45 Ontario Energy Board, EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," September 17, 2008. p.20.

46 Ontario Energy Board, EB-2010-0379, Report of the Board, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors," December 4, 2013 (corrected report).

a large number of distribution companies in Ontario seems to have motivated the Ontario Energy Board to develop, refine and rely on benchmarking methodologies, including those measuring relative cost performances, as a substitute for more traditional, formal and costly cost of service proceedings for the many distribution companies.

The Régie has instructed the experts in this proceeding to conduct a total cost benchmarking or an econometric cost comparison analysis in order to assist it in selecting a stretch factor. In Section VII, we present our econometric cost comparison analysis. Nevertheless, we caution against mechanical use of econometric cost comparison analysis for setting the stretch factor, as it cannot be a complete substitute for what we believe is ultimately an exercise based on regulatory judgement as well as regulatory precedence. The central idea behind the cost benchmarking and comparison approach to the stretch factor is that a firm's current level of costs *vis-à-vis* a comparison group is a relevant factor in determining the *magnitude* of a stretch factor for its PBR plan. Moreover, the belief is that a statistical cost comparison analysis is a good and robust approach to determine whether a firm is operating at an efficient level. We have several observations in this area.

First, the regulatory economic theory underpinning the stretch factor in a PBR formula is that given a significant change in the regulatory environment—in this case moving from cost-of-service regulation to PBR—the firm will have improved incentives to operate more efficiently *than it has had in the past*—on either the cost side, the demand side or both. It seems to us that if it were possible to measure, one would compare the *firm's* expected efficiency incentives post adoption of PBR plan to the efficiency incentives prior to the change to PBR. Comparisons to the efficiency of other firms appear to entail an assumption—likely tacit and untested—that moving from cost-of-service to PBR provides greater incentives to higher-cost firms. To the extent that this assumption is invalid, such comparisons are not relevant for predicting how or by what amount the firm will improve performance under the new regulatory regime. In other words, with respect to the selection of an appropriate stretch factor, the firm is competing with its *own* past performance, not the past performance of other firms. A firm that is very efficient and a top performer *vis-à-vis* its peers prior to the adoption of PBR could still realize cost and demand efficiencies from the change to PBR. Under the cost benchmarking and comparison approach, however, a top performer would have a stretch factor of zero.[47]

Second, cost benchmarking and comparison analysis attempts to estimate the costs of the target firm relative to the broader comparison group, and to base the stretch factor on whether costs for a firm are significantly lower, significantly higher or are not statistically distinguishable from the average. To the best of our knowledge, however, there is no explicit economic theory guiding the actual stretch factor that should apply for an average firm, a superior firm or an inferior firm. The values used by the Ontario

[47] As we discuss below, it seems that a key assumption of the cost benchmarking and comparison approach is the belief that the statistical model predicts the production possibility frontier, so that a top performer is on the frontier and thus it could make no further improvements. The production possibility frontier refers to all the combinations of output that a firm can produce if it uses all its resources and inputs efficiently. *See*, Karl E. Case and Ray C. Fair, *Principles of Economics*, Sixth Edition, (Upper Saddle River, N.J. : Prentice Hall), 2002, p. 30.

Energy Board seem to be based more on regulatory judgement and precedence than any formal theoretical linking of the cost benchmarking and comparison results and the stretch factor.

Third, the assumption underlying the cost benchmarking and comparison approach to the stretch factor seems to be that the statistical model can estimate the production possibilities frontier, so that a top performer is expected to make no further improvements and gets a stretch factor of zero. There are two concerns with this assumption. First, most regulated firms—and even some firms in markets that are more competitive—are unable to operate on the production possibility frontier.[48] The second is that cost benchmarking and comparison analysis relies on econometric estimates of cost models, the results of which can be sensitive to assumptions, specifications and estimators used, as the Ontario experience shows. In other words, even if some firms were operating on the production possibility frontier, it is unlikely that econometric analysis can explicitly account for all the factors that make one firm be far removed from the frontier and another firm be closer to the frontier.[49] Some amount of misspecification is likely to occur in any econometric modelling, and can be a factor in explaining a firm's performance *vis-à-vis* other firms' performance.

Regulatory judgement, as well as regulatory precedence, can play an important role in selection of the stretch factor. In that light, several factors can help inform the regulator of the stretch factor:

- When initially moving from rate-of-return regulation to PBR, the change in regulatory structure can lead to efficiency gains by the regulated firm. The stretch factor provides customers with a "first cut" of the share of the increased productivity growth due to the initial incentive effects of PBR. Thus, a stretch factor should be more common in "first generation" PBR plans than in subsequent generation plans.

- The regulatory regime of the company that will be under the PBR plan is relevant. HQT has been under cost-of-service regulation annually since the mid-2000s up through 2019 when it began its first "partial" PBR plan that applies only to O&M costs. The long series of annual rate cases implies a higher stretch factor, *all else equal*. At the same time, since HQT is already operating to some extent under the efficiency enhancing incentives of PBR, at least for O&M costs, there will likely be less "low hanging fruit" in subsequent plans, thus arguing for a lower stretch factor than would otherwise be the case.

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48 X-inefficiency is a reason why some firms do not operate on the production possibility frontier and refers to firms not engaging in cost-minimization behavior, something that results from cost-of-service regulation. *See*, W. Kip Viscusi, Joseph E. Harrington Jr. and David E. M. Sappington, *The Economics of Regulation*, Fifth Edition, (MIT Press), 2018, pp. 78-79 for a discussion of X-inefficiency. See also, Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-1069 for a discussion on the efficiency effects of rate-of-return regulation.

49 There are many intangible factors that can explain why one firm performs differently from another, such as the quality of workers and management, the quality and strength of the procurement process—*i.e.*, negotiation and bargaining with suppliers—and the amount of X-inefficiency in the company. To the extent that data limitations preclude such relevant factors from being included in an econometric cost model, departures from "average" efficiency may well represent the effect of these other factors, rather than failure to minimize cost.

- The sample of companies used for the TFP study is also relevant. If the sample consists of companies that are operating under a PBR plan, then the measured productivity growth already contains some of the effects of the stretch factor. In contrast, a TFP study sample that includes only companies under rate-of-return regulation would not capture this effect. Our sample of U.S. transmission companies are under cost-of-service regulation by the FERC. Many of those companies are under "formula rates" meaning that the companies' rates are frequently aligned with underlying costs and there is less ability to take advantage of regulatory lag. At the same time, the FERC also provides incentives to transmission companies, most in the form of premiums on return on equity for meeting certain public policy objectives.

- Under a revenue cap plan, if an output growth is not included in the revenue cap formula, then any output growth becomes an implicit stretch factor so that the final stretch factor becomes the explicit one adopted by the regulator plus the expected output growth.

- The establishment of a capital tracker in a PBR plan generally lowers the incentive effects of the plan because some capital remains under cost of service, as does a PBR plan that focuses only on O&M. This would argue for a lower stretch factor because fewer of the firm's inputs are exposed to the PBR incentive properties.

2. Regulatory decisions on stretch factors

Because regulatory precedence can be instructive in the selection of a stretch factor, we review some recent decisions applicable to electricity transmission and distribution companies in North America. We discuss the decisions by the Ontario Energy Board, the Alberta Utilities Commission, the British Columbia Utilities Commission and the Massachusetts Department of Public Utilities.

i. OEB Third Generation Incentive Regulation

In its 2008 report for the Third Generation IR mechanism, the Ontario Energy Board adopted, in part, an empirical approach to determine the stretch factor based upon the relative cost performance of Ontario electricity distributors.[50] The methodology, put forward by Pacific Economics Groups ("PEG"), followed two approaches by which the Ontario distribution companies were placed in three cohorts based on their relative cost efficiency. The first step involved an econometric benchmarking assessment of the companies in the Board's jurisdiction, which compared the actual O&M costs of each company to that predicted by an econometric model. The Board followed a similar approach in the Fourth Generation IR, except the costs considered included capital costs as well. As per the econometric benchmarking, a distributor was deemed "statistically superior" if the actual costs were lower and statistically different from that predicted by the model. A distributor was labelled "statistically inferior" if the actual costs

[50] Ontario Energy Board, "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," July 14, 2008.

were higher and statistically different from those predicted. All other companies were considered "average cost performers".

The second approach analyzed the Ontario distributors' O&M costs per unit of distribution output. The normalized costs were then compared to the average unit costs of a peer group and ranked based on the percentage differences between the actual O&M unit cost and that of the peer group. Those companies that came out as superior in both approaches were placed in Group I. Companies labelled inferior in both approaches were placed in Group III. All other distributors were placed in Group II. As per this approach, companies were not bound to their groups for the entirety of the PBR duration and could move between groups based on their annual O&M cost performance. The Board sought recommendations from various experts on the magnitude of stretch factors to be applicable for each group. In a supplemental report,[51] the Board laid out the sizes of the stretch factors for each group, presented below in Table 3.

TABLE 3: OEB 3RD GEN IR STRETCH FACTORS

Group	Benchmarking Evaluation	Stretch Factor
I	Statistically superior and in top quartile on O&M unit cost comparison	0.20%
II	In middle two quartiles on O&M unit cost comparison	0.40%
III	Statistically inferior and in bottom quartile on O&M unit cost comparison	0.60%

Source: EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors"

ii. OEB Fourth Generation Incentive Regulation

In a 2013 report as part of its fourth generation incentive regulation mechanism, the Board employed an econometric benchmarking approach to judge coast performance of the Ontario distribution companies and laid out a range of relative cost performance on which to base the stretch factor.[52] As per this approach, the Board places the companies in one of five groups, as presented in Table 4.

[51] Ontario Energy Board, EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," September 17, 2008

[52] Ontario Energy Board, EB-2010-0379, Report of the Board, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors," December 4, 2013 (corrected report).

TABLE 4: OEB 4TH GEN IR STRETCH FACTORS

Group	Cost Performance Range (Actual vs. Predicted)	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within ±10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

Source: EB-2010-0379, Report of the Board, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors."

iii. Hydro One Transmission Benchmarking

In 2018, Hydro One Sault Ste. Marie filed an application with the Ontario Energy Board to escalate transmission rates through an IRM. Hydro One proposed a revenue cap formulation and through its consultants Power System Engineering, Inc. ("PSE"), conducted a TFP study and an econometric benchmarking study that determined the S-factor. PEG also submitted a TFP study and an econometric benchmarking study.

Both, PSE and PEG, employed an econometric approach to determine the stretch factor, similar to that used in the Fourth Generation IR by OEB, except that this proceeding was specific to transmission companies. PSE's analysis concluded that Hydro One's actual costs were 31.8% below the predicted benchmark costs and used the ranges postulated by the OEB to recommend a 0.0% stretch factor. PEG's analysis, on the other hand, concluded that Hydro One was an average cost performer and recommended that a 0.30% stretch factor be applied. In its order, the Board agreed with PEG's recommendation and proposed a 0.30% stretch factor be applied to the revenue cap formula.[53]

iv. Alberta Utilities Commission

In 2010, the Alberta Utilities Commission (AUC) initiated a PBR plan applicable to electric and natural gas distribution companies in the commission's jurisdiction.[54] The plan moved the companies from cost-of-service regulation to an I-X PBR mechanism that contained earnings sharing and a capital K-Factor. The AUC adopted a stretch factor of 0.2 percent and explained its decision by stating:

> Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. Accordingly, the Commission considers that a stretch factor for Alberta companies should be on the lower end of the 0.2 to 0.6 per cent ranges

53 Ontario Energy Board Decision EB-2018-0218.

54 Alberta Utilities Commission Decision 2012-237.

> recommended by PEG and the UCA's experts. The Commission observes that the CCA expressed its preference for a stretch amount on the lower side of the 0.19 - 0.5 percent range recommended by its experts, PEG. The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable. This stretch factor should apply to the companies' plans for the duration of the PBR term.[55]

The AUC commented on the incentive effects of the stretch factor, as well as the X-factor, and stated:

> Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[56]

In 2016, the AUC adopted a second-generation PBR plan for the electric and natural gas distribution companies.[57] While the AUC recommended maintaining a stretch factor for the second generation—in part because removal of the capital trackers from the first generation PBR plan was expected to increases efficiency incentives—the exact stretch factor adopted is uncertain. As the AUC stated:

> The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable range of values, between -0.79 and +0.75. The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, *inclusive of a stretch factor*, will be 0.3 per cent.[58] [emphasis added]

v. FortisBC Inc. (FBC) and FortisBC Energy Inc. (FEI)

FortisBC Inc. ("FBC") and FortisBC Energy Inc. ("FEI") both filed applications for approval of multi-year PBR plans for years 2014 through 2018 – FBC for its electricity distribution/transmission business and FEI for its natural gas distribution business. Prior to this application, FBC had undergone a mix of PBR and cost-of-service rate setting mechanisms. While the British Columbia Utilities Commission ("BCUC") directed both, FBC and FEI, to conduct a benchmarking study for the next phase of PBR, the absence of

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55 Alberta Utilities Commission Decision 2012-237, p. 104.

56 Alberta Utilities Commission Decision 2012-237, p. 104.

57 Alberta Utilities Commission Decision 20414-D01-2016.

58 Alberta Utilities Commission Decision 20414-D01-2016, p. 45.

an indicator of the companies relative cost efficiency made the BCUC look at stretch factor considerations in other jurisdictions. The commission considered Fortis' own proposed stretch factor of 0.5%, but deemed this contrary to FEI's assertion that they had realized significant efficiencies under previous PBR regimes. As expert witnesses in the case, PEG recommended a stretch factor of 0.2% due to average cost performance based on the available evidence. The commission also considered the range of stretch factors agreed to in Ontario's Third Generation IR and ultimately proposed stretch factors of 0.2% for FEI and 0.1% for FBC.[59]

vi. Massachusetts Department of Public Utilities

The DPU, in D.P.U. 17-05, adopted a performance based ratemaking mechanism for NSTAR Electric Company and Western Massachusetts Electric Company ("NSTAR").[60] In that decision, the DPU adopted a consumer stretch factor of 0.25% (25 basis points) when inflation exceeds two percent.[61] The DPU described the consumer stretch factor as intending to reflect expected future gains in productivity due to the move from cost-of-service regulation to incentive regulation. In its decision, it summarized the position of NSTAR indicating that the determination of a consumer dividend is largely subjective and that there is a lack of quantitative, empirical basis for establishing its magnitude.[62]

vii. Summary

Table 5 provides a summary of the stretch factor decisions summarized above. Both Ontario and British Colombia use total cost benchmarking and regulatory judgement for the stretch factor, while the regulators in Alberta and Massachusetts rely on judgement.[63] The table shows a stretch factor range from 0.10% to 0.30% for the electricity transmission and distribution companies.

59 British Columbia Utilities Commission Decision, G-139-14, p. 83.

60 Massachusetts DPU 17-05.

61 Massachusetts DPU 17-05, pp 394-395.

62 Massachusetts DPU 17-05, p. 395.

63 As discussed above, while total cost benchmarking starts with an econometric model, the determination of how the results of the model translate into specific stretch factors still requires regulatory judgement.

TABLE 5: SUMMARY OF RECENT STRECTH FACTOR DECISIONS

Jurisdiction	Stretch Factor	Methodology
Ontario (Hydro One Sault Ste. Marie, electricity transmission, 2019-2026)[1]	0.30%	Total cost benchmarking and judgement
Alberta (electricity and natural gas distribution, first generation plan, 2012-2017)[2]	0.20%	Judgement
British Colombia (Fortis BC Inc. (FBC) electricity distribution/transmission, Fortis BC Energy Inc. (FEI) natural gas, 2014-2018)[3]	FBC: 0.10% FEI: 0.20%	Total cost benchmarking and judgement
Massachusetts (NSTAR, electricity distribution 2018-2023)[4]	0.25% when inflation exceeds two percent	Judgement

Sources:

[1]Ontario Energy Board Decision EB-2018-0218

[2]Alberta Utilities Commission Decision 2012-237

[3]British Columbia Utilities Commission Decision, G-139-14, p. 83

[4]Massachusetts DPU 17-05 pp 394-395

E. Additional components of price and revenue caps

i. Inflation factor

As discussed in Section III, the inflation factor is a key component of a PBR plan and directly affects the X-factor. When the inflation factor measures input price inflation, the X-factor is the TFP of the industry. When the inflation factor measures economy-wide output price inflation, however, the applicable X-factor is different. Specifically, it is the sum of the difference in total factor productivity growth rates between the regulated firm and the rest of the economy ($\dot{T} - \dot{T}^E$) plus the difference, if any, in the input price growth rates between the rest of the economy and the regulated firm ($\dot{W}^E - \dot{W}$).

ii. Additional factors

In addition to the inflation factor, other important components of a PBR plan can include an exogenous factor, a service quality factor and earnings sharing mechanism. Exogenous factors are to account for costs that are outside the control of the firm, such as changes in tax law, natural disasters and other force majeure events. Some PBR plans also include a service quality factor to account for possible incentives in a PBR plan to cut costs by lowering investments, which can negatively affect service quality or reliability in electricity. Sometimes, instead of a service quality factor, the plan contains a K-factor—*i.e.*, capital trackers—that maintains a cost-of-service framework for some investments that are important for service quality or reliability purposes.[64] Of course, the more costs that are outside the PBR plan, the less powerful the incentive effects of the plan. Finally, earnings sharing mechanisms provide a sharing of earnings above a certain amount between shareholders and customers.

64 These tend to be more typical in electricity PBR plans.

IV. Total Factor Productivity Methodology

A. Methodology

Productivity is the ratio of the output quantity that a company produces to the input quantity that it uses to produce its output. It is a measure of how good a firm is in turning inputs into outputs.

$$Productivity = \frac{Outputs}{Inputs} \tag{15}$$

Productivity *growth* provides a measure of performance over time, defined as:

$$Growth\ in\ Productivity_t = Output\ growth_t - Input\ growth_t \tag{16}$$

Often, multiple metrics make up the outputs produced by a company, and the same applies for inputs as well. In the context of electric utilities, outputs typically are the total number of customers that a utility serves, the total MWh delivered or the peak MW demand. For the transmission sector, an additional output measure that is used is the kilometers of transmission lines. Deflated revenues is another output measure that is used in productivity studies. On the input side, a firm utilizes many different types of inputs and as mentioned earlier, it is common in productivity studies to categorize them into three broad categories: labor, MR&S and capital.

Total-factor Productivity is a productivity measure that comprises all of a firm's inputs, while a productivity measure that uses multiple, but not necessarily all inputs, is a *Multi-factor Productivity*. As is common in productivity studies, we use an indexing approach to combine multiple output and input quantities into a single output and input index. The growth in the total/multi factor productivity index is the difference in the growth of the output and input indices, respectively.

B. Output

Unlike distribution utilities, where the end user is easily identifiable, and the revenue collected from a given customer class is available, the identification of outputs is not as straightforward in the case of electric transmission. We instead use metrics that provide an approximate measure of the services that transmission companies provide. Given the relative dearth of transmission TFP studies, we have identified, based on our survey of the few studies in other regulatory proceedings, the following quantities as potential outputs for this study:

1. Peak demand
2. Total energy output

3. Total length of transmission lines

Items 1 and 2 are common electricity output measures used in cost-of-service studies. The classification part of cost-of-service studies assigns electricity costs based on the underlying cost drivers, with three major ones being: customer, energy (MWh) and demand (MW). The major cost driver for electricity transmission is peak demand (item 1 above). As peak demand increases, the transmission company may need to increase its capacity to provide service and maintain the appropriate level of reliability and service quality. We thus use peak demand as a measure of output in our TFP study.

Energy (MWh) is an important cost driver for electricity demand but in cost-of-service studies, energy is more of a cost driver for electricity generation, than for electricity transmission. Nevertheless, energy is a physical output that transmission companies provide, in addition to demand. The FERC's output accounts for transmission companies include energy, and energy is a typical rate design component in transmission tariffs, in addition to peak demand. For these reasons, there is justification for considering the use of energy as an output measure in a TFP study.

Finally, some recent transmission TFP studies use length of transmission lines as a measure of transmission output. At first, it seems odd to include transmission length as an output in a TFP study, as transmission companies do not record kilometers of transmission lines as an output category and it is not used as such in the ordinary course of business or in the FERC accounts as an output measure. Nevertheless, there is economic logic behind the use of transmission length as an output measure. Electricity is a network industry, that connects sets of nodes to each other—*e.g.*, generation units, transmission and distribution substations and ultimately customers. Electricity companies connect these nodes through transmission and distribution lines. The length of these lines is a measure of the size of the network and, to a lesser extent, the "quality" of the network as more kilometer lines for a given number of nodes represents greater reliability and more redundancies.

TFP studies typically combine the different output measures into one overall index by weighting the outputs by their associated revenues. One issue to overcome in a transmission TFP study that is not present in a distribution TFP study is that the transmission outputs do not generally have revenues associated with them because our transmission companies are vertically integrated companies and provide transmission services to their affiliated distribution and generation companies. While transmission companies do sell to third parties, the sales are only a portion of total transmission output.

Instead of weighting transmission output by revenue, it is typical in transmission TFP studies to weigh the outputs based upon the impact the output has on the total costs of the transmission company. We obtain these estimates when we conduct our econometric cost comparison analysis in Section VII.

C. O&M

Labor and MR&S make up a utility's operations and maintenance (O&M) expenses. Labor expenses are readily available from the FERC Form 1 data and we calculate MR&S expenses from the same data. We obtain quantity indices for these two inputs by deflating their respective expenses by an appropriate input price index—a labor input price index and an MR&S input price index. We provide the data used and the details of this approach in Section VI.

D. Capital

Measuring the capital quantity and the capital price is a challenging part of a TFP study. With respect to capital quantity, a challenge in measuring the quantity of capital is that at any point in time there are varying vintages of capital that a company uses, some purchased recently and others that have been in use for much longer periods. It is, therefore, important to measure and compare the capital stock in such a way as to account for the capital services it produces and the corresponding annual value over time. Measuring the reproduction cost of transmission plant expressed in constant dollars permits such a comparison. One common method of measuring the reproduction cost of transmission plant expressed in constant dollars is the perpetual inventory method, which accounts for the presence of different vintages of capital stock at any given point in time.[65] We use this approach in our TFP study.

Another challenge in measuring capital quantity is that unlike labor, where a firm "rents" and "consumes" labor service in the same period, a capital asset delivers a flow of capital "services" throughout the life of the asset. In order to measure capital quantity and the services that a unit of capital provides, one needs to make an assumption about how the flows of capital services change throughout the life of the asset—*i.e.*, how does the asset depreciate? Specifically, does the asset produce a relatively constant flow of capital services throughout its life—a methodology known as O*ne-Hoss Shay* depreciation. Alternatively, does the asset provide a flow of capital services that diminishes over time as the asset ages, and at what rate does that diminution occur—with one such methodology being the G*eometric Decay (Geometric Depreciation)*. The selection of O*ne-Hoss Shay* or G*eometric Decay* can have a material impact on the results of TFP studies and we discuss each approach in detail below.

There is also a challenge with respect to the capital price. Unlike labor where its "price" is the result of labor market competition and labor demand and supply dynamics and is usually readily observable, the "price" of capital is not readily observable for assets in many industries—especially for the types of

[65] L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

assets involved in the electricity transmission business.[66] Unlike commercial real estate, for example, where both the buildings and space within buildings is bought, sold, and rented, there is no readily available secondary, rental market for transmission assets that we can observe. Measuring the "price" of capital in a TFP study thus requires that we *impute* a "rental price" of capital and that it measures the "opportunity cost" to the firm of holding a unit of capital.[67]

Therefore, it is important to measure and compare the capital stock and services and the opportunity cost of capital in such a way as to account for the capital services it produces and its monetary value over time. This measurement is based on three integral components: annual capital cost (annual capital expenses), capital quantity (services), and capital price ("rental" rate for the capital services). These components relate to each other as follows:

$$Capital\ Cost_t = Capital\ Quantity\ Index_t \times Capital\ Price\ Index_t \tag{17}$$

Measuring the capital quantity in a TFP study requires two steps. The first is to calculate the capital quantity (or capital stock) in the *benchmark year*.[68] The second is the calculation of capital quantity for every subsequent year.

The benchmark year refers to the first year for which capital information is available. For the U.S. sample of transmission companies, the first year of readily available data is 1988. For HQT, the first year with available data is 2001. We calculate the capital stock in the benchmark year by deflating the benchmark year plant in service by a weighted average capital price index. For the U.S. sample of utilities, we use the Handy-Whitman index[69] to deflate the capital expenses. For HQT, we used a composite capital price index.[70] The following is the benchmark year capital stock formula that we use in our study:

$$Benchmark\ Capital\ stock = \frac{Gross(or\ Net)\ Plant\ in\ service_{Benchmark\ year}}{\sum_{i=1}^{s}\left(i \times \left(\frac{P_{Benchmark-s+i}}{\sum_{i=1}^{s} i}\right)\right)} \tag{18}$$

Where *P* is the capital price index for the respective utility sample and *s* is the transmission asset life. The denominator in the formula above weights the price indices going back over the asset's service life.

66 The annual capital price is similar to an annual rent charged for space in a building.

67 The use of a firm's capital assets for a year comes at the "opportunity cost" of not employing the capital assets—or the value of the capital—in the next best alternative. The rental price of capital is that "opportunity cost".

68 Continuing the building analogy, if rental buildings are bought, sold, and rented on a square-foot basis, the benchmark capital stock is analogous to the number of square feet in a building in the year in which reliable data became available.

69 The Handy-Whitman Index provides cost trends different types of utility construction published by Whitman, Requardt and Associates. At the time of procurement, the HW index for January 2020 was unavailable. In order to calculate the index for 2019, we use the CAGR from 2014 to 2019 to impute the value for January 2020, and then calculate the resultant HW index for 2019

70 A capital price index is available for the 1983-2019 period. For years prior to 1983, we impute the values of the capital price index by using the annual growth rate of the Handy-Whitman index for the North Atlantic region, adjusted for Purchasing Power Parity, and applying it to the 1983 HQ price index going backwards.

The numerator calls for the use of either the gross plant in service or the net plant in service. The selection of gross or net plant in service depends upon the selection of the methodology one adopts with respect to the “capital services” that a unit of capital produces and importantly the assumption one makes about how capital services change over the life of an asset. As mentioned above, the two most common capital service methodologies are the O*ne-Hoss Shay* methodology and the G*eometric Decay methodology*. Use of the *One-Hoss Shay* is more consistent with the use of gross plant in service, while use of the *Geometric Decay* is more consistent with the use of net plant in service. While the economic literature contains additional capital service methodologies, the O*ne-Hoss Shay* and the *Geometric Decay* methodologies are the methodologies used most often in regulatory TFP studies, are well established in the economics literature and relatively straightforward to calculate when data are available.[71] We discuss each in detail in the next section.

1. One-Hoss shay

Under O*ne-Hoss Shay*, the key assumption is that over the life of the asset, the services that a unit of capital provides do not generally decline.[72] This means that an asset would generally yield a constant level of capital services throughout its useful life and then collapse in a heap. A light bulb and a chair are common examples. Charles R. Hulten, a well-known expert on capital, stated:

> “Of these patterns, the one hoss shay pattern commands the most intuitive appeal. Casual experience with commonly used assets suggests that most assets have pretty much the same level of efficiency regardless of their age— a one year old chair does the same job as a 20 year old chair, and so on.”[73]

One-Hoss Shay assumes that capital maintains its value over the entirety of its useful life until it is retired. The formula for the capital quantity index under *One-Hoss Shay* is:

$$Captial\ Qty\ Index_t = Capital\ Qty\ Index_{t-1} + \frac{Gross\ Additions_t}{P_t} - \frac{Gross\ Retirements_t}{P_{t-s}} \qquad (19)$$

Specifically, the capital quantity index is created by adding deflated gross additions and subtracting deflated gross retirements from the previous year’s quantity index, where retirement assets are deflated by the index from the year when the assets came into service. Under the *One-Hoss Shay* view

71 *See*, W. Erwin Diewert, Measuring Capital, National Bureau of Economic Research Working Paper 9526, February 2003 for a discussion of additional assumptions about the form of depreciation in the measurement of capital.

72 A one-hoss shay is a light, covered carriage drawn by a horse and is immortalized in a poem by Oliver Wendell Holmes Sr. “The Deacon’s Masterpiece: or the Wonderful “One-Hoss-Shay. A Logical Story.”

73 *See*, Charles R. Hulten, “The Measurement of Capital,” p. 124, *Fifty Years of Economic Measurement*, E.R. Berndt and J.E. Triplett (eds.), Studies in Income and Wealth, (The National Bureau of Economic Research, Chicago: The University of Chicago Press), Volume 54, 1991.

of the world, the formula does not account for depreciation as a one-year old unit of capital provides the same services as a ten-year old unit of capital.

With respect to the "price" of capital—*i.e.*, the opportunity cost/rental price of owning a unit of capital—*One-Hoss Shay* implies a certain rental price formula. With *One-Hoss Shay*, the asset provides the same amount of services each year over the life of the asset. Therefore, the annual payments are constant, apart from the effect of inflation in the purchase price of new assets. In order to justify the purchase of the new asset, the discounted sum of the annual payments—adjusted for asset inflation—would equal the purchase price.[74] Specifically, the "rental" price of capital is:

$$P_t = \left(\frac{1-k-uz}{1-u}\right) \times \frac{(r-i)}{(1+r)} \times \left[1-\left(\frac{1+i}{1+r}\right)^s\right]^{-1} \times HW_{t-1} \tag{20}$$

Where: k = investment tax credit rate,[75] u = corporate profits tax rate,[76] z = present value of the depreciation deduction on new investment, r = cost of capital,[77] i = expected inflation rate over the lifetime of assets,[78] s = asset lifetime,[79] HW_{t-1} = Handy-Whitman index in the prior year.

The first term in the above formula accounts for both, the tax benefit derived from owning depreciable capital assets and the income tax owed as a result. The tax benefit issue captures the idea that being able to deduct tax depreciation lowers the price of an asset—*e.g.*, if you buy something for $100, it actually costs less because you get some of the $100 back in lower taxes. The second term factors in the cost of capital return over time and is a measure of the foregone return, offset by appreciation—change in HW.[80] For the cost of capital, we assume the average of the cost of debt[81] and the authorized return on equity (ROE).[82] We calculate the present value of the depreciation deduction on new investment as:

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74 Equation (20) is derived from the basic principle that the purchase price of an asset is equal to the discounted cash flows from that asset.

75 There has been no general investment tax credit for small business in the US over this sample period of this study.

76 Internal Revenue Service, Statistics of Income Historical Table 24.

77 For the cost of capital, we assume the average of the cost of debt and the authorized return on equity (ROE).

78 Calculated using the yield on 30-year treasury bonds from US Department of the Treasury and CPI-U figures from the US Bureau of Labor Statistics.

79 We assume an asset service life of 46 years, the average asset life that HQT uses in their capital calculations.

80 W. Erwin Diewert, "Measuring Capital," National Bureau of Economic Research Working Paper 9526, February 2003, formula 44, p. 35.

81 The cost of debt for each company is calculated from FERC Form 1 as the ratio of interest on long-term debt to total long term debt: Total long term debt: FERC Form 1, page 112, line 24, Interest on long term debt: FERC Form 1, page 117, account 427, line 62c.

82 Rates of authorized return on equity are obtained from a rate case tracker compiled by Regulatory Research Associates (RRA) from SNL. *See* "Rate Cases – Pending and Past." The FERC regulates rates for transmission companies but we use ROE rates for distribution companies due to the lack of a publicly available centralized repository that tracks rate cases for transmission services. We also believe that trends in distribution rates are correlated with trends in transmission rates and therefore, serve as a good proxy for the cost of capital for transmission. For companies that do not have ROE information for a given year(s), we extend the most recently available ROE until the next available rate case. If a company has an authorized ROE of zero, we treat it as a "missing" entry and carry over the most recent available ROE.

$$z = \frac{2}{T \times (T+1)} \times \sum_{i=1}^{T} (T+1-i) \times \left(\frac{1}{1+R}\right)^{i} \tag{21}$$

Where: R = rate of return for discounting depreciation deductions, T = tax lifetime of asset. We use a value of 0.10 for R and a value of 23 years for T, which gives a value of 0.511 as per the above formula.[83]

2. Geometric decay

Under *Geometric Decay*, the assumption is that over the life of the asset, capital services decline.[84] That is, the capital services that a unit of capital provides in year 1, is greater than the capital services the unit of capital provides in subsequent years, with the capital services in the latter years being significantly lower. While there are different assumptions one can make about the rate of decline, the *Geometric Decay* methodology assumes that capital depreciates at a constant rate over its useful life.

Under the *Geometric Decay* methodology, capital services—*i.e.*, capital quantity—at a given point in time is a function of the *undepreciated* capital that remains and any additions made. Specifically, the capital quantity index under *Geometric Decay* is:

$$Capital\ Qty\ Index_t = Capital\ Qty\ Index_{t-1} \times (1-d) + \frac{Gross\ Additions_t}{P_t} \tag{22}$$

Where d is the assumed depreciation rate held constant over time—calculated as the reciprocal of the assumed asset service life and adjusted for the double-declining balance rate—and P_t is an appropriate price index which is a proxy for capital construction costs.[85]

The "price" of capital under *Geometric Decay* is given by:

83 The formula for the depreciation benefit is based on the sum of year depreciation and is an accelerated depreciation method. We performed sensitivities for the calculation of the present value of depreciation deduction, based on the depreciation schedules published by the IRS for capital assets, US IRS Publication 946, "How to Depreciate Property," Appendix A, Table A-1. The US IRS provides depreciation tables for property on a 3-year to 20-year basis. We used 15-year and 20-year recovery periods as most appropriate for transmission and company-specific cost of capital to determine company specific depreciation deduction estimates. We did not find our TFP results particularly sensitive to this latter approach.

84 *See*, W. Erwin Diewert, "Measuring Capital," National Bureau of Economic Research Working Paper 9526, February 2003, Section 10.

85 We obtain the depreciation rate by adjusting the reciprocal of the transmission asset service life for the declining balance rate for transmission capital assets.

$$Depreciation\ Rate = \left(\frac{1}{Asset\ service\ life}\right) \times Declining\ balance\ rate$$

We use an asset service life of 46 years, as used by HQT in their capital asset determination. The double-declining balance rate gives an accelerated depreciation rate, obtained from US BEA – Table 3 BEA Rates of Depreciation, Service Lives, Declining-Balance Rates, and Hulten-Wykoff Categories.

$$Capital\ Price\ Index_t = \left(\frac{1-k-uz}{1-u}\right) \times \left[d_t \times HW_t + HW_{t-1} \times \left[r_t - \left(\frac{HW_t - HW_{t-1}}{HW_{t-1}}\right)\right]\right] \quad (23)$$

Where the first term is identical to the first term in *One-Hoss Shay* and corresponds to the taxes owed plus the tax depreciation benefits. The component in the bracket deals with depreciation (d_t) and return (r_t) and corresponds to how much it costs to hold that asset in a given year, rather than using the money somewhere else.[86]

3. Approach used in TFP study

One-Hoss Shay and *Geometric Decay* have support in the economics literature as well as in regulatory decisions.[87] On the latter, in 2012 the Alberta Utilities Commission reviewed competing TFP studies for electricity and natural gas distribution companies with one study using *One-Hoss Shay* and others using *Geometric Decay* and adopted a TFP study using *One-Hoss Shay*.[88] In 2018, the Massachusetts Department of Public Utilities also adopted a TFP study for electric distribution that used *One-Hoss Shay*, stating: "[w]hile the gradual depreciation of capital assets is necessary for accounting and cost recovery purposes, a capital's assets contributions to a company's productivity remains relatively constant until it is retired."[89] On the other hand, the Ontario Energy Board's recent decisions involving Hydro One Transmission adopted *Geometric Decay*.[90] In telecommunications, the Federal Communication Commission's early price cap plans involved TFP studies that used *Geometric Decay*.[91]

In our TFP study, we employ *One-Hoss Shay* but provide TFP results using *Geometric Decay* as part of our sensitivity analysis. We use *One-Hoss Shay* for several reasons. Similar to the sentiments expressed by Charles R. Hulten above, we believe that *One-Hoss Shay* has the more intuitive appeal for electricity transmission. The services provided by a unit of transmission capital corresponds to certain "functionalities" underlying the asset. For example, the functionality provided by towers and poles is to support, sustain and carry the overhead conductors and devices—*i.e.*, the transmission lines. Either the towers and poles provide this functionality or they do not, there really is no in-between. The

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86 In terms of the use of HW, the basic idea is that the depreciation of an asset is based on its value in the current year (hence HW_t), while the cost of using that asset, as opposed to selling it at the beginning of the year, is based on last year's asset value (hence HW_{t-1}).

87 On the issue of the economic literature, *see*, W. Erwin Diewert, "Measuring Capital," National Bureau of Economic Research Working Paper 9526, February 2003, Section 10.

88 One of the authors of this study, Dr. Ros, appeared in that proceeding on behalf of the Alberta Utilities Commission see AUC Proceeding No. 566.

89 Mass D.P.U. 17-05 p. 390.

90 We understand that the two TFP studies in that proceeding used *Geometric Decay*.

91 Federal Communications Commission, CC Docket Nos. 94-1 and 96-262 *In the Matter of Price Cap Performance Review for Local Exchange Carriers and Access Charge Reform*, adopted May 7, 1997.

functionality provided by towers and poles, therefore, are more consistent with *One-Hoss Shay*.[92] Similarly, for transmission lines the functionality is to provide capacity (MW) and to transport electricity (MWh) from point A to point B on a transmission network. A new transmission line with capacity of 200 MW tends to have close to the same level of capacity and transport the same amount of electricity at the end of its life.[93]

Moreover, in the case of electricity transmission TFP, one output measure that is commonly used is total kilometer of transmission lines. *One-Hoss Shay* is intuitively appealing when it comes to this measure of output. Specifically, the underlying capital assets that "produce" kilometers of transmission lines consist of the towers, poles and conductors. Importantly, those capital assets produce the same kilometers of transmission lines in year one of their deployment as in year twenty, thirty or forty. There is little to no loss in capital efficiency with respect to those transmission assets (inputs) producing kilometers of transmission lines (output).

Geometric Decay assumes a greater loss of capital efficiency in the early years compared to the latter years, which is counterintuitive. In equation (22) above, d is the assumed depreciation rate and is held constant over time. What this implies is that the early year losses in capital efficiency are larger than the losses in efficiency in the latter years. For example, a one-dollar capital asset with a depreciation rate of 10 percent will lose $0.10 of capital efficiency in year 1, and $0.09 in year 2. Relatedly, *Geometric Decay* implies that the amount of capital services—*e.g.*, functionalities—that the asset provides at the end of its life is very low compared to the capital services that the brand-new asset provides. In our tower example and using a 46-year life, *Geometric Decay* implies that the towers' ability to support, sustain and carry the conductors at the end of its life is (1/46) of its ability to support, sustain and carry the conductors when initially deployed. We do not believe this implication of *Geometric Decay* is intuitively consistent with the functionalities that transmission assets provide.

E. Previous transmission TFP and X-factor studies

There have been very few transmission TFP studies conducted that are publicly available. Below we lay out what we could find dealing with TFP and X-factor calculations for the transmission industry in North America and Australia.[94] In 2018, Hydro One Sault Ste. Marie ("HOSSM") filed an application with the Ontario Energy Board to escalate transmission rates through an IRM. Hydro One proposed a revenue cap formulation by conducting a TFP study that determined the X-factor and an econometric

92 The example involving towers and poles is directly comparable to the chair example in *One-Hoss Shay*.

93 While it is the case that the towers, poles and conductors require periodic maintenance, the ultimate objective of the maintenance is to keep the assets from "failing" while maintaining a constant level of capital services—*i.e.*, functionalities. In any event, O&M expenses—whether or not having the ultimate objective of maintaining a constant level of capital services—are accounted for separately in a TFP study.

94 In Section II, we summarized the first MRI approved by the Régie for HQT, applicable for four years starting in 2019 and including an X-factor of 0.57% using the Kahn-methodology and applicable to non-capital expenses.

benchmarking study that determined the S-factor. This proceeding featured two independent studies conducted by two external consultants. Hydro One retained PSE, an energy-consulting firm in Madison, Wisconsin, to conduct the productivity study on their behalf. The OEB retained PEG to review both, the TFP study and the econometric benchmarking.

PSE proposed a revenue cap formula that featured an inflation index, an X-factor and a stretch factor. Revenue cap formulas usually include an output factor, which accounts for the growth of outputs but PSE excluded this from the formulation because Hydro One's projections did not forecast any growth in outputs for the relevant duration of the IRM. Both firms used a Törnqvist-Theil index to calculate productivity, though there were differences in the assumptions used regarding the exclusion of certain expenses, the capital price specifications, and more notably, the period considered for the study. Both consultants produced a negative long-run TFP trend, though the magnitudes varied due to the differences outlined above. PSE presented a -1.71% TFP growth over the 2004-2016 sample period while PEG calculated a -0.34% TFP growth over the 1996-2016 sample period. Both made a final X-factor recommendation of 0% due to the Board's reluctance to include negative X-factors in the revenue cap formula in the Fourth Generation Incentive Regulation Proceeding.[95]

For the stretch factor, PSE used results from the benchmarking study to show that Hydro One's actual costs were considerably lower than those predicted by their statistical model, which warranted a 0% stretch factor. PEG, on the other hand, showed that the company's costs were lower than predicted by the model but not to the extent calculated by PSE. Based on the average cost performance, PEG recommended a 0.30% stretch factor. In Decision and Order EB-2018-0218, the OEB approved a 0% X-factor and 0.30% stretch factor.

The Australian Energy Regulator ("AER") publishes an annual benchmarking report for five major transmission network service providers ("TNSP") in Australia. Economic Insights, an Australian economic consulting firm, conducts the annual study on behalf of the AER.[96] The output measures used in the TFP calculation are: (1) energy throughput, (2) ratcheted maximum demand, (3) number of end-users, (4) circuit length, and (5) energy not supplied (this enters as a negative term in the output TFP calculation). The input measures used in the TFP calculation are opex and several measures of capital where the capital services are in *physical units*, not *monetary units*, these consist of: (1) overhead lines (proxied by overhead MVAkms), (2) underground cables (proxied by underground MVAkms), and (3) transformers and other capital (proxied by transformer MVA). They use Törnqvist-Theil to combine inputs and outputs to calculate the growth of a multi-factor productivity index. The results of the most recent annual update showed a TFP growth of -1.10% over the 2006-2018 period, -2.19% over the 2006-2012 period and -0.02% over the 2012-2018.[97]

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95 EB-2010-0379.

96 Annual Benchmarking Report – Distribution and Transmission 2019

97 *See*, Economic Insights, "Economic Benchmark Results for the Australian Regulator's TSNP Annual Benchmarking Report," Denis Lawrence, Tim Coelli, and John Kain, 5 September 2019, Table 2.1.

V. TFP Model and Sample Selection

A. TFP model

We have built a model in Microsoft Excel that calculates TFP growth for U.S. electricity transmission companies. We use utilities in the U.S. because these companies are required to report financial data to a central regulatory agency, the FERC, and the publicly available data source contains all the metrics relevant to the calculation of TFP growth. Our TFP model contains all the data that we use in our study including other non-FERC, publicly available data that we need to calculate TFP and that are not contained within the FERC database, which we describe in detail in subsequent sections.

Table 6 describes some of the key components of the model. The "Model Inputs" provide a user with the flexibility to test different scenarios and gauge the sensitivity of the TFP results to the different assumptions about the capital methodology, the asset life, the outputs used and the cost share weights and the inclusion or exclusion of common costs. We select a set of assumptions for our TFP recommendation that produces our "base case" results and we provide sensitivity analysis around this base case.

TABLE 6: KEY COMPONENTS OF THE TFP MODEL

Model Sheet	Description
Model Inputs	Contains a range of user inputs and sensitivities that drive TFP results
TFP Growth	Calculates the combined multi-factor productivity based on input and output indices
Output	Calculates the growth of the combined output TFP index
Input	Calculates the growth of the combined input TFP index
O&M Non-Labor	Calculates the quantity and price index for materials, rents, and services (MR&S)
O&M Labor	Calculates the quantity and price index for labor
Capital Quantity	Calculates the quantity index based on inputs selected for capital specification
Initial Capital Stock	Calculates the capital stock in the benchmark year based on inputs selected for capital specification
Capital Price	Calculates the capital price index based on inputs selected for capital specification

Source: Authors' TFP Model.

B. Sample selection criteria and construction of TFP data base

As discussed in Section III, the X-factor in a PBR plan represents the *industry* TFP, not the TFP of the individual firm whose tariffs the PBR plan regulates. Setting an X-factor based on the industry TFP ensures that the X-factor is exogenous, is outside the control of the firm, and that the link between the company's own costs and allowed prices is broken—resulting in improved incentives for efficiency. Setting the X-factor based upon the company's own TFP does not match the incentive effects of setting the X-factor based upon the industry TFP.

There is no single repository with consistent and transparent financial and operation data for Canadian electric utilities available on an annual basis.[98] Instead, we use data for electric utilities in the United States. In the U.S., the FERC regulates interstate electric transmission and natural gas and oil pipelines. As such, electric utilities are required to submit regulatory financial accounts to the FERC on an annual basis by filling out Form 1. This repository is publicly available and published by the FERC, roughly around the second quarter of every year, for the prior financial year.[99] The FERC releases Form 1 data in a format not readily usable. Additionally, a significant amount of work goes into processing the data into a clean, usable format. Some third-party vendors process the raw FERC Form 1 data and make it available for use via a subscription service. Our primary data source for this study uses the processed FERC Form 1 data released by SNL Financial, a financial analytics company, which is a part of Standard & Poor's (S&P) Global Market Intelligence. Canadian regulators have used the FERC data on U.S. companies in past proceedings to calculate total factor productivity in both, electric distribution and transmission.[100]

For our study, we use 74 U.S. electricity transmission companies. Our general approach for selecting a sample of transmission companies is to select as many companies as possible, governed by data constraints. Productivity growth can exhibit significant volatility at the individual firm level for a number

[98] Stats Canada calculates MFP for the utilities sector in Canada, but it is not specific to electricity transmission and does not present information by company. From 2001 to 2018, MFP went from 110.547 to 97.929, a decline of about 0.7% per year. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610020801.

[99] Form 1 for electric utilities are available going back to 1994 on the FERC website: https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-1-electric-utility-annual

[100] The Ontario Energy Board recently used U.S. transmission companies in TFP and total cost benchmarking studies, *see* Ontario Energy Board Decision EB-2018-0218. The Alberta Public Utilities Commission used U.S. distribution companies in TFP studies in 2012 and 2016 for use in setting an X-factor, *see* Alberta Utilities Commission Decision 2012-237 and 2014-D01-2016.

of reasons and the selection of a large sample of companies can help reduce that volatility. Attempting to select a sample of companies that better "matches" HQT would result in a much lower number of companies and lead to potentially more volatility than a larger sample. HQT is a very large company, larger than any in the FERC database, and restricting the sample to companies closest to HQT would leave relatively few companies in the sample. Our TFP growth rate is a weighted average growth rate of the individual company TFP growth rates, where we use company size as a weight, thereby putting more weight on the larger company in our sample than the smaller ones.[101]

FERC Form 1 data is available for investor-owned utilities ("IOUs") including diversified utilities—*e.g.*, T&D only companies as well as TD&G companies—as these are required to file this form to the FERC every year. At present, there are 142 such companies in the U.S.[102] We downloaded processed FERC Form 1 data from SNL for the 142 IOUs in the US that provide transmission services. We did not include in our sample any US utilities that do not provide transmission services—*e.g.*, companies that only provide generation or distribution services.

The input metrics (labor costs, materials and services costs and capital costs) and output metrics (length of transmission lines, system peak demand and total energy output) to the model come from FERC Form 1 data obtained from the SNL Financial platform. Table 7 below provides a summary of the metrics used in the study and the corresponding sources.

101 Moreover, our TFP study is a study of TFP *growth rates*, and not the absolute level of TFP. TFP *growth* is not necessarily systematically related to the overall size of a firm.

102 While government-owned companies—such as municipals—would ideally form a relevant comparison for HQT given its government-ownership status, they are not required to report financial data to the FERC.

TABLE 7: TFP STUDY METRICS AND SOURCES

Category	Components	Source
Input Costs	Labor Materials & Services (M&S) Capital	FERC Form 1 (SNL Financial & Raw FERC Form 1 files)
Output Quantity Metrics	Length of Transmission Lines Peak Demand Total Energy*	FERC Form 1 (SNL Financial & Raw FERC Form 1 files)
Price Index	Labor Price Index Wage levels Capital Price Index M&S Price Index Depreciation Rate Cost of Debt Return on Equity	Employment Cost Index - US BLS Occupational Employment Statistics – US BLS Whitman, Requardt and Associates, LLP US Bureau of Economic Analysis (BEA) US BEA FERC Form 1 (SNL Financial) Regulatory Research Associates (RRA)
Business Conditioning Variables (for benchmarking study)	% of Transmission Plant Average Substation Capacity No. of Transmission substations Average Voltage of Transmission lines % of Underground Lines % of Transmission Plant Overhead	FERC Form 1 (Raw FERC Form 1 files)
Economy-wide TFP estimates*	Canadian Business Sector TFP Growth Canadian Economy Input Price Growth	Multifactor Productivity Data – Statistics Canada GDP-PI – Statistics Canada

*Note: This series becomes a component of the X-factor to the extent that the price cap formula (RPI – X) utilizes an economy-wide measure of Inflation.

To carry out this study, we required transmission capital cost data from 1988 to 2019 and data for all other variables (summarized in Table 7) from 1994 to 2019. We reviewed the FERC Form 1 data available for the 142 IOUs in the US that provide transmission services and checked for any unreported or anomalous data. We removed some utilities from the sample due to those data constraints. In a few instances, we made changes to the underlying data when we concluded that the data were obviously a typo, in order to preserve the company in the sample. We also removed some utilities due to data issues regarding mergers or acquisitions.[103] In the Appendix, we provide details for each of the 142 utilities, which ones we did not use and why as well as any changes we made to the data in order to preserve the maximum number of companies in our sample. Table 8 below provides the final list of companies used

[103] For example, in 2010, Ameren's three Illinois operating companies merged to become Ameren Illinois Company. Ameren Illinois Company started filing FERC Form 1 after 2010, but there is no data available before 2010.

in our TFP and econometric cost comparison analysis, including their peak demand and geographical location.

TABLE 8: LIST OF COMPANIES USED IN TFP AND BENCHMARKING STUDY

Company Name	State	2019 System Peak (MW)	Company Name	State	2019 System Peak (MW)
Florida Power & Light Company	FL	24,241	Portland General Electric Company	OR	3,765
Southern California Edison Company	CA	21,929	Potomac Edison Company	OH	3,609
Commonwealth Edison Company	IL	20,949	Evergy Metro, Inc.	MO	3,441
Pacific Gas and Electric Company	CA	18,731	Dayton Power and Light Company	OH	3,246
Duke Energy Carolinas, LLC	NC	17,594	Idaho Power Company	ID	3,242
Georgia Power Company	GA	16,572	Northern Indiana Public Service Company	IN	3,149
Duke Energy Progress, LLC	NC	13,434	Entergy Mississippi, LLC	MS	2,994
Alabama Power Company	AL	11,542	Indianapolis Power & Light Company	IN	2,876
PacifiCorp	OR	10,334	New York State Electric & Gas Corporation	NY	2,847
Duke Energy Florida, LLC	FL	9,973	Tucson Electric Power Company	AZ	2,726
Public Service Electric and Gas Company	NJ	9,753	Duquesne Light Company	PA	2,662
PECO Energy Co.	PA	8,428	Louisville Gas and Electric Company	KY	2,609
PPL Electric Utilities Corporation	PA	7,729	Atlantic City Electric Company	DE	2,598
Northern States Power Company - MN	MN	7,469	Cleco Power LLC	LA	2,492
Arizona Public Service Company	AZ	7,030	Gulf Power Company	FL	2,472
Union Electric Company	MO	6,961	Mississippi Power Company	MS	2,381
Oklahoma Gas and Electric Company	OK	6,817	Evergy Kansas South, Inc.	KS	2,297
Baltimore Gas and Electric Company	MD	6,706	Monongahela Power Company	OH	2,121
Public Service Company of Colorado	CO	6,619	El Paso Electric Company	TX	1,985
Niagara Mohawk Power Corporation	NY	6,518	Public Service Company of New Mexico	NM	1,937
Nevada Power Company	NV	5,611	Sierra Pacific Power Company	NV	1,808
Potomac Electric Power Company	DC	5,431	Avista Corporation	WA	1,656
Consolidated Edison Company of New York, Inc.	NY	5,130	Central Maine Power Company	ME	1,616
Connecticut Light and Power Company	CT	4,775	Public Service Company of New Hampshire	NH	1,609
Southwestern Electric Power Company	LA	4,727	ALLETE (Minnesota Power)	MN	1,573
Dominion Energy South Carolina, Inc.	SC	4,714	Rochester Gas and Electric Corporation	NY	1,507
Entergy Arkansas, LLC	AR	4,513	Northern States Power Company - WI	WI	1,305
Puget Sound Energy, Inc.	WA	4,498	United Illuminating Company	CT	1,216
NSTAR Electric Company	MA	4,449	Entergy New Orleans, LLC	LA	1,155
Kentucky Utilities Company	KY	4,352	Empire District Electric Company	MO	1,111
Southwestern Public Service Company	TX	4,261	Central Hudson Gas & Electric Corporation	NY	1,109
Cleveland Electric Illuminating Company	OH	4,188	Orange and Rockland Utilities, Inc.	NY	1,040
San Diego Gas & Electric Company	CA	4,175	Ohio Valley Electric Corporation	OH	1,021
Public Service Company of Oklahoma	OK	4,104	Otter Tail Corporation	MN	924
Tampa Electric Company	FL	4,075	Green Mountain Power Corporation	VT	612
Delmarva Power & Light Company	DE	4,041	MDU Resources Group Inc.	ND	564
West Penn Power Company	OH	4,012	Black Hills Power, Inc.	SD	420

Source: SNL Financial FERC Form 1.

A. Output index

As discussed in Section IV, we consider three metrics from the FERC Form 1 data as transmission outputs for the purpose of the TFP study.

- Length of Transmission Lines:[104] Utilities list every transmission line they own in the annual FERC Form 1 reports along with the length and other characteristics such as voltage, construction costs, and type of supporting structure. This quantity is in miles of transmission line.

- System Peak Demand:[105] Companies report the total peak demand on their transmission system, if any. This metric, however, is only available from 2004, which would restrict the sample period for this study. We use an alternative definition of peak demand in the FERC data, which is available starting in 1994. This quantity is in megawatts (MW) of peak demand observed during a given year.

- Total Energy Output:[106] Similar to the TFP analysis by the AER, we also consider total annual energy output as an output measure for transmission utilities. This quantity is in megawatt-hours (MWh) observed by a utility over the course of a year.

For each output measure, we calculate an index and combine the output quantities into a single measure of output growth. We do this by calculating an output index using a chain-weighted Törnqvist-Theil indexing methodology.[107] Specifically, we calculate the annual growth rate of the output index by using the following formula:

$$ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) = \sum\nolimits_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Output\ Qty\ Index_{j,t}}{Output\ Qty\ Index_{j,t-1}}\right) \qquad (24)$$

Where:
$share_{j,t}$ = cost elasticity share of the output component for *j* in year *t*

$Output\ Qty\ Index_{j,t}$ = Quantity index for output component *j* in year *t*

The growth is the *weighted average* of the growth rates of the individual output metrics. Since we do not have revenues to weigh the individual output measures, we use the results from our econometric cost comparison analysis to determine the weights for each metric—*i.e.*, we calculate the cost elasticity

[104] FERC Form 1, Page 424, Length in Miles, line no. 44c.

[105] FERC Form 1, Page 401b, Monthly Peak Megawatts, column d.

[106] FERC Form 1, Page 401b, Total Monthly Energy, column b.

[107] *See* Michael Denny, Melvyn Fuss and Leonard Waverman, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," p. 188, in *Productivity Measurement in Regulated Industries*, edited by Thomas G. Cowing and Rodney E. Stevenson, Academic Press, 1981.

for each output. We describe our econometric cost comparison analysis and results in Section VII. Based upon our econometric analysis we weigh peak demand at 60% and miles of transmission lines at 40%. For our base case model, we do not use total energy as an output, but do consider it in our sensitivity analysis.

We calculate the growth rate for each company and each year in the sample. We calculate the average output growth for a given year as an average of the growth rate of all companies for that given year, weighted by each company's output.[108] Table 9 below presents the annual growth rate for the individual output metrics over different sample periods.[109] Over the longest period, peak demand grew the fastest at an annual rate of 1.10%, followed by miles of transmission lines at 0.57%. Total energy demand growth was relatively flat during the period. Peak demand growth slowed considerably so that by the more recent periods there was significantly faster growth in transmission lines. Total energy experienced negative growth during the more recent periods.

TABLE 9: ANNUAL GROWTH OF TRANSMISSION OUTPUT

Year	Transmission Lines (miles)	System Peak Demand (MW)	Total Energy (MWh)
1995 - 2019	0.57%	1.10%	0.03%
2000 - 2019	0.90%	0.65%	-0.70%
2005 - 2019	1.00%	0.51%	-0.61%
2010 - 2019	1.38%	0.31%	-0.29%

Source: Authors' TFP Model. Results are weighted average growth rates of all companies weighted by peak demand and transmission line length.

B. Input index

1. Labor

The labor quantity index provides a measure of the labor services that utilities "consume" for transmission services every year. Until 2002, companies were required to report the total number of full-time and part-time employees on the payroll in their FERC Form 1 submissions. This number, however, was an aggregate headcount and did not distinguish between the different activities that the

108 Specifically, we weigh by the combined output measure consisting of peak demand and miles of transmission lines.

109 In Table 11, we provide the annual growth rate for the combined outputs weighted by the cost elasticity shares we obtained from our econometric cost comparison analysis.

utility was responsible for. In the absence of such a labor headcount measure, we use labor costs and a labor price index to determine a quantity index.

Every utility reports the total cost of labor in the FERC Form 1. Since our TFP sample includes vertically integrated utilities, we only consider labor costs that are specific to transmission services. The FERC also differentiates between operations[110] and maintenance[111] (O&M) wage and non-wage expense. The total transmission O&M labor expense is the sum of these two wage measures. We define the quantity index for labor as the ratio of the total wages paid and a labor price index—*i.e.*, we calculated deflated wages. For the labor price index, we use data from the Occupational Employment Statistics ("OES"), which measures the average wage for all occupations. The OES is an annual report published by the Bureau of Labor Statistics at the state level for a range of industries in the U.S. We use the mean 2019 wage level for the *Electric Generation, Distribution and Transmission Industry*. To obtain the wage level for other years, we adjust the 2019 wage by the Employment Cost Index ("ECI")[112] from respective years, calculated as:

$$Wage_t = \left(\frac{Wage_{2019} \times ECI_t}{ECI_{2019}}\right) \tag{25}$$

For a given year, we calculate the labor price index as the ratio of the mean wage level for the year to that for a "base" year:

$$Labor\ Price\ Index_t = \frac{Wage_t}{Wage_{base\ year}} \tag{26}$$

In this study, we treat 2001 as the base year, the first year for which financial data for HQT are available. The final TFP results are not sensitive to the selection of the base year but it does play a role in the econometric cost comparison analysis. The selection of 2001 as the base year allows us to remain consistent across our analysis for the U.S. sample and HQT.[113] We then define the labor quantity index as the ratio of the total transmission O&M labor expense to the labor price index.

$$Labor\ Quantity\ Index_t = \frac{Total\ Transmission\ Payroll_t}{Labor\ Price\ Index_t} \tag{27}$$

110 FERC Form 1, page 354, line 4b.

111 FERC Form 1, page 354, line 14b.

112 The Employment Cost Index (ECI) is published by the US Bureau of Labor Statistics (BLS). Specifically, we use the ECI that corresponds to private industry workers in the utilities industry. These indices are available for 2001-2019. For values prior to 2001, we referenced Table 9 in the Employment Cost Index, Historical Listing – Volume 5.

113 The price index for each input is dependent on the base year and we use it in the econometric cost comparison analysis to determine the dependent variable. As HQT is included in the sample of companies and the first year of data available for HQT is 2001, we select 2001 as the base year.

2. Materials, rents and services

Utilities in the U.S. do not report MR&S—non-wage O&M expenses. As is standard in TFP studies, we classify O&M expenses net of labor expenses as MRS—that is, we subtract labor expenses from total transmission O&M to arrive at MRS expenses.[114] Specifically, we define MR&S expense as:

$$MR\&S\ Expenses_t = Total\ Transmission\ O\&M_t\ - Total\ Transmission\ Payroll_t$$

Similar to labor quantity, we obtain the MR&S quantity index by deflating MR&S expenses by a price index. For the U.S. sample, we use the Gross Domestic Product Price Index (GDP-PI)[115], adjusted for the GDP-PI from the base year, to determine MR&S quantity.

$$MR\&S\ Price\ index_t = \left(\frac{GDP - PI_t}{GDP - PI_{base\ year}}\right) \tag{28}$$

We then calculate MR&S quantity as:

$$MR\&S\ Quantity\ index_t = \left(\frac{MR\&S\ Expenses_t}{MR\&S\ Price\ Index_t}\right) \tag{29}$$

3. Capital

As elaborated in detail in Section IV, we use *One-Hoss Shay* for capital quantity and price. We use gross investment in 1988 as the benchmark year for the initial capital stock calculation.[116] We calculate the capital stock in subsequent years by adding constant dollar plant additions and subtracting constant dollar plant retirements. We use the following data to arrive at the capital quantity index for any given year: Gross transmission plant in service;[117] Net transmission plant in service;[118] Transmission plant additions;[119] Transmission plant retirements;[120] Depreciation rate;[121] A price index as a proxy for utility construction costs.[122]

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114 FERC Form 1, page 321, line 112.

115 The GDP-PI is published by the United States Bureau of Economic Analysis (BEA). Table 1.1.4, Gross Domestic Product.

116 *See* Section IV for the formula we use for the benchmark year as well as for subsequent year additions and retirements.

117 FERC Form 1, page 207, account 259.1, line 58g.

118 Used for *Geometric Decay* sensitivity analysis. Net transmission plant is obtained after subtracting the accumulated depreciation from the gross transmission plant in service. Accumulated depreciation: FERC Form 1, page 219, line 25b.

119 FERC Form 1, page 206, account 259.1, line 58c.

120 FERC Form 1, page 207, account 259.1, line 58d.

121 Used for *Geometric Decay* sensitivity analysis.

122 We use the Handy-Whitman Index, which provides cost trends for different types of utility construction published by Whitman, Requardt and Associates. This index assumes a base year of 1973 (index = 100). We reset the base year for the Handy-Whitman index to 2001 to remain consistent with the approach adopted for labor and MR&S. For 2004 onwards, the

4. Combined input index

Once we calculate the quantity indices for each input component—labor, MR&S, and capital—we combine them using a chain-weighted Törnqvist-Theil indexing methodology to provide the growth of a single input index. The growth rate of the combined input index is:

$$ln\left(\frac{Input_t}{Input_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Input\ Qty\ Index_{j,t}}{Input\ Qty\ Index_{j,t-1}}\right) \quad (30)$$

Where:
$share_{j,t}$ = cost share of input component *j* in year *t*
$Input\ Qty\ Index_{j,t}$ = Quantity index for component *j* in year *t*

The cost share for each component is the respective components' expenses as a percentage of the total input expenses. For example, we calculate the cost share for labor in a given year as:

$$Labor\ Cost\ Share_t = \frac{Labor\ O\&M\ Expenses_t}{Labor\ O\&M\ Expenses_t + MR\&S\ Expenses_t + Capital\ Expenses_t} \quad (31)$$

We calculate the input growth rate for a given year as a weighted average of the growth rate of the combined input index for all companies for that given year, weighted by a combined measure of the output quantity metrics.

Similarly, the annual growth rate for the combined *input price index* is:

$$ln\left(\frac{Input\ Price_t}{Input\ Price_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Input\ Price\ Index_{j,t}}{Input\ Price\ Index_{j,t-1}}\right) \quad (32)$$

Where $Input\ Price\ Index_{j,t}$ refers to the input price index for component *j* in year *t.* The combined input price index is a metric that we use in our econometric cost comparison analysis as well as in calculation of the X-factor in a revenue cap plan where the I in I-X is the economy-wide output price inflation.

Table 10 below presents a summary of the annual growth rates for the three input quantities, input prices and the shares of the inputs. The fastest growing input quantity during the period was MR&S, averaging 5.58%, followed by capital at 0.93% and labor at 0.69%. In terms of input prices, capital experienced the fastest growth during the period at 4.07% followed by labor price at 2.85% and MR&S

firm produces two observations for every year, one in January and another in July. On examining the spreadsheets provided by Whitman, Requardt and Associates, we found that the resultant index for a year is given by:

$$HW_t = \left(\frac{HW_{Jan,t} + 2 \times HW_{July,t} + HW_{Jan,t+1}}{4}\right)$$

At the time of procurement, the HW index for January 2020 was unavailable. In order to calculate the index for 2019, we use the CAGR from 2014 to 2019 to impute the value for January 2020, and then calculate the resultant HW index for 2019.

price (GDP-PI) at 1.87%. Capital prices fell significantly in the more recent periods accompanied, however, by significant increases in the capital quantity growth. The capital share of total costs was close to 75 percent throughout the period, followed by MR&S at approximately 20 percent and then labor at 5 percent.

TABLE 10: GROWTH OF TRANSMISSION INPUT QUANTITIES AND PRICE INDICES

	Labor			Materials, Rents & Services (MR&S)			Capital		
Year	Growth of Quantity	Growth of Price	Cost Share	Growth of Quantity	Growth of Price	Cost Share	Growth of Quantity	Growth of Price	Cost Share
1995 - 2019	0.69%	2.85%	5.37%	5.58%	1.87%	20.43%	0.93%	4.07%	74.20%
2000 - 2019	0.88%	2.84%	5.16%	4.92%	1.93%	21.57%	1.39%	3.67%	73.27%
2005 - 2019	1.42%	2.70%	4.89%	4.49%	1.88%	22.24%	1.68%	4.15%	72.87%
2010 - 2019	0.55%	2.56%	4.66%	4.73%	1.68%	22.09%	2.17%	1.35%	73.25%

Source: Authors' TFP Model. Results are weighted average growth rates of all companies weighted by peak demand and transmission length.

C. TFP results base case

In this section, we present the results of our TFP study for the base case scenario. Our base case scenario includes the following main assumptions:

1. Use of *One-Hoss Shay* for capital quantity and price, with asset life assumption of 46 years.
2. Use of two output metrics—miles of transmission lines and peak demand with output weights of 40% and 60%, respectively.
3. Does not include a share of A&G expenses nor a share of the general plant in transmission capital expenses.[123]

TFP growth is the difference between the output and input growth indices. Based on equations (24) and (30), TFP growth is:

$$Growth\ of\ MFP\ Index = Growth\ of\ Output\ Index - Growth\ of\ Input\ Index \tag{33}$$

$$ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = ln\left(\frac{Output_t}{Output_{t-1}}\right) - ln\left(\frac{Input_t}{Input_{t-1}}\right) \tag{34}$$

Table 11 below presents our TFP growth rate for the U.S. sample of transmission utilities based on the assumptions outlined above. For the entire period—1994 to 2019—TFP growth was -1.04% and we find that TFP growth slowed considerably in recent periods—*i.e.*, became more negative. We observe that output growth remained relatively constant throughout the period, slowing down only modestly in the

[123] Some TFP studies include a share of A&G and General Plant in electricity distribution and transmission studies, while other studies do not. We discuss the merits of including or not including these costs further below.

more recent periods. Input growth, on the other hand, increased considerably throughout the period and is an important reason for the overall TFP growth slowdown during the period.

In terms of partial factor productivity, we find capital PFP growth was -0.05% during the entire period, but slowing down significantly throughout the period. We find O&M PP growth was -3.38% during the period and remained stable throughout the entire period.

Our studies' finding of negative transmission TFP growth is aligned and consistent with previous transmission TFP growth studies that also found negative TFP growth for transmission services. In Section IV, we reviewed the results of the few transmission TFP studies using the same FERC Form 1 data source but using a different set of transmission companies, different capital methodology, and a shorter period. As mentioned in that Section, in 2018, Hydro One Sault Ste. Marie filed an application with the Ontario Energy Board to escalate transmission rates through an IRM. Two consultants produced TFP studies and both resulted in negative TFP growth. Specifically, PSE calculated a TFP trend of -1.71% over the period 2005 to 2016 while PEG calculated a TFP trend of -0.34% over the period 1996 to 2016.[124]

[124] In Section IV, we also highlighted a recent transmission TFP growth study of the five major transmission network service providers in Australia which also consistently found negative TFP growth over different periods.

TABLE 11: ANNUAL GROWTH OF TFP INDEX – US SAMPLE

Year [A]	Growth of Output Index [B]	Growth of Input Index [C]	Growth of TFP Index [D]	Growth of PFP (O&M) [E]	Growth of PFP (Capital) [F]
1995	3.09%	0.51%	2.57%	-0.40%	3.00%
1996	0.97%	0.23%	0.74%	0.09%	1.32%
1997	-0.93%	1.23%	-2.16%	-5.91%	-0.82%
1998	1.89%	1.74%	0.14%	-4.26%	2.58%
1999	2.15%	-0.46%	2.61%	-8.45%	5.52%
2000	0.36%	-0.36%	0.72%	0.37%	0.77%
2001	0.21%	2.53%	-2.32%	-6.73%	-0.08%
2002	2.30%	0.01%	2.29%	5.23%	1.62%
2003	1.15%	1.44%	-0.29%	-1.90%	-0.01%
2004	0.37%	5.26%	-4.89%	-16.10%	-0.51%
2005	3.80%	4.99%	-1.19%	-8.20%	4.07%
2006	2.32%	1.25%	1.07%	0.37%	1.04%
2007	0.49%	0.56%	-0.07%	-1.08%	-0.40%
2008	-1.51%	2.59%	-4.10%	-9.54%	-2.37%
2009	-1.88%	-0.47%	-1.41%	3.37%	-2.54%
2010	2.78%	2.69%	0.08%	-2.80%	0.95%
2011	0.58%	0.01%	0.57%	-1.88%	0.68%
2012	0.09%	2.19%	-2.10%	-2.29%	-1.83%
2013	-0.58%	3.86%	-4.44%	-6.22%	-3.67%
2014	0.22%	4.15%	-3.93%	-4.65%	-3.33%
2015	1.49%	2.93%	-1.44%	-1.28%	-1.75%
2016	-0.20%	2.71%	-2.91%	-3.19%	-2.50%
2017	1.52%	1.61%	-0.09%	0.67%	0.14%
2018	1.42%	2.15%	-0.73%	-1.44%	-0.12%
2019	0.05%	4.78%	-4.73%	-8.23%	-2.90%
1995 - 2019	***0.89%***	***1.93%***	***-1.04%***	***-3.38%***	***-0.05%***
2000 - 2019	***0.75%***	***2.24%***	***-1.50%***	***-3.28%***	***-0.64%***
2002 - 2019	***0.80%***	***2.37%***	***-1.57%***	***-3.29%***	***-0.75%***
2005 - 2019	***0.71%***	***2.40%***	***-1.69%***	***-3.09%***	***-0.97%***
2010 - 2019	***0.74%***	***2.71%***	***-1.97%***	***-3.13%***	***-1.43%***

Source and Notes: Authors' TFP Model. Results are weighted average growth rates of all companies weighted by peak demand and transmission length.

[D] = [B] – [C]. [E] and [F] represent the growth of the partial productivity index based on O&M and capital, respectively.

D. Sensitivity analyses

In addition to the base case, we test the sensitivity of TFP growth for the U.S. sample under several alternative assumptions. First, we use the *Geometric Decay* capital specification for the measurement of the capital stock and capital price index and calculate it as we described in Section IV. Second, we provide sensitivity around the asset life used in our capital price formula, which is 46 in our base case. Third, we test a 50/50 share for peak demand and miles of transmission lines as well as one that includes total energy as an additional output item and we weigh peak demand at 60%, miles of transmission lines at 30% and total energy at 10%. Finally, we include a share of A&G and General Plant.[125] Table 12 below summarizes the results and shows the impact of altering an assumption *while holding all other elements of the base case constant*.

TABLE 12: ANNUAL GROWTH OF TFP FOR US SAMPLE - SENSITIVITIES

Year	Base Case TFP	Geometric Decay Capital	Capital Asset Life 44 Yrs	Capital Asset Life 48 Yrs	Output Share (50%/50%)	Output Share (60%/30%/10%)	A&G and General Plant
1995 - 2019	-1.04%	-1.82%	-1.24%	-0.85%	-1.11%	-1.06%	-0.32%
2000 - 2019	-1.50%	-2.50%	-1.70%	-1.33%	-1.49%	-1.62%	-0.74%
2005 - 2019	-1.69%	-2.91%	-1.93%	-1.51%	-1.67%	-1.81%	-0.97%
2010 - 2019	-1.97%	-3.22%	-2.32%	-1.69%	-1.91%	-2.07%	-1.26%

Source: Authors' TFP Model

The use of *Geometric Decay* results in significantly slower TFP growth during all periods considered. Over the period, our base case TFP growth—using *One-Hoss Shay*—was -1.04% compared to -1.82% when using *Geometric Decay*. These results are neither expected nor unexpected, as there is no theoretical reason why *Geometric Decay* results in faster or slower TFP growth compared to *One-Hoss Shay*, *holding all other factors constant*—the issue is an empirical one.

With respect to asset lives, a reduction in the asset life reduces TFP growth, while an increase in asset life increases TFP growth.[126] Specifically, a reduction in asset life to 44 years—instead of 46 years in our base case—results in TFP growth of -1.24% while an increase in the asset life to 48 years results in TFP growth of -0.85%.

With respect to the weighting of the output measure, moving from a 60% peak weight and 40% miles of transmission weight to a 50/50 share has little impact of TFP growth. It slows TFP growth slightly over

[125] We calculate the share of A&G as the ratio of total transmission O&M expenses to total electric O&M expenses multiplied by total A&G. For General Plant we determine the share as the ratio of transmission Plant to total electric Plant multiplied by total General Plant. Other transmission TFP studies cited in this report exclude certain A&G costs (pension and benefits) as well as O&M electric expenses such as fuel purchases when determining the share of A&G to allocate to transmission.

[126] With longer asset lives, new capital investment (and the associated growth in capital quantity) is lower.

the period and increases slightly during the more recent period. The incorporation of total energy as an additional output measure consistently lowers TFP growth, not surprisingly since total energy was the slowest growing of the three output measures.

Finally, the incorporation of A&G and general Plant results in faster TFP growth during the entire period. We also find, however, that when we add A&G and general Plant to different TFP assumptions the effect can be to lower TFP growth.[127] In regulatory costing theory, A&G and general Plant are examples of common costs, which by definition are avoidable only if the firm ceases operation. Economic costing theory by itself does not provide an optimal and generally accepted methodology to allocate common costs to different operating divisions, such as the generation, transmission, distribution and retailing divisions in a vertically integrated electricity firm. The share of A&G and general Plant that we allocated to the transmission services for this sensitivity is one approach, but it does not hold any more weight than other potential approaches.[128]

In general, we do not believe that the inclusion of common costs should significantly affect the results of an electricity transmission TFP study. Inclusion of any share of A&G and general Plant is ultimately subjective and we have found that the methodology used can result in large swings in TFP growth rate. Ultimately, the objective of a transmission TFP study is to measure the TFP growth driven by the highly capital-intensive electricity transmission sector that consist of towers and poles, conductors, substations, *etc*. A&G and general Plant are the types of costs that most businesses incur—*e.g.*, office buildings, legal fees, human resource, *etc.*,—and it does not seem reasonable to us that their inclusion in a transmission TFP study should be a main driver of the results. TFP decisions in Massachusetts and Alberta also exclude common costs from TFP studies.[129]

[127] For example, TFP growth in our model with *Geometric Decay* is -1.82%. Further including A&G and general Plant lowers TFP growth to -1.95%.

[128] We examined the impact of alternative approaches such as unilaterally selecting different shares of A&G and general Plant costs to recover from transmission and found the resulting TFP growth rates to be very sensitive and somewhat volatile to the share selected. In addition, when we exclude pension and benefits from A&G costs and exclude electric O&M expenses such as fuel purchases, as has been done in other TFP studies cited in this report, it lowers TFP growth to -0.71% compared to -0.32%.

[129] *See*, AUC Decision 2012-237 and Mass DPU Decision 17-05, p. 389.

VII. Econometric Cost Comparison

A. HQT data

To perform the econometric cost comparison, HQT provided us with financial and operational data comparable to the data for the U.S. transmission companies published in FERC Form 1. We highlight below differences between HQT and U.S. costs. In addition, HQT underwent a material structural change and made several accounting changes during the period as we described in Section II. We discuss the implications of these changes for purposes of econometric cost comparison.

The first significant difference between the HQT and U.S. datasets is the period. The first year of the HQT sample is 2001, the year in which HQ structurally divested its assets among the three entities—Hydro-Québec TransÉnergie, Hydro-Québec Production and Hydro-Québec Distribution. Therefore, our econometric cost comparison analysis begins in 2001.

With respect to output, we use the same output metrics for HQT that we used in our U.S. TFP study—length of transmission lines (in kilometers), system peak demand, and total energy output. HQT provided us the data for each output measure for each year from 2001 to 2019. We use these variables as independent variables in our econometric cost comparison. HQT also provided us with the data for the other independent variables that we use in our econometric cost comparison study: percent of transmission plant in electric plant, average substation capacity, substation count per km of transmission line, average voltage of transmission lines, and percent of transmission lines that are underground.

With respect to HQT O&M costs, unlike FERC Form 1, HQT tracks the employee headcount for transmission services in terms of full-time equivalent (“FTE”) of employees. We use this variable as a direct measure of the labor quantity for HQT. For the labor price, we calculate it as the ratio of the total payroll expenses to the FTE for a given year. We exclude pension and benefits from the definition of total payroll and we exclude capitalized labor from the definition of labor because these expenses are included in the company’s capital expenses. Regarding non-labor O&M, we calculate MR&S expenses as total O&M expenses net of labor. Here, too, we exclude capitalized costs from the MR&S definition because these expenses are included in the company’s capital expenses. For the MR&S price index, we use the Canadian GDP-PI[130] for final domestic demand, using 2001 as the base year.

With respect to capital, HQT provided financial data for property, plant and equipment (“PP&E”), which we use for the capital quantity measurement. The general approach follows the approach we used for the U.S. sample. We calculate an initial capital stock using 2001 as the benchmark year—the earliest

[130] Statistics Canada. Table 36-10-0130-01 Gross domestic product price indexes, annual.

year for which data are available—the capital stock for subsequent years employs *One-Hoss Shay* and utilizes average asset life of 46 years.

Regarding the price of capital, HQT does not use the Handy-Whitman index for work related to capital asset measurement. Instead, we use a capital price index for transmission lines, substations, buildings, and telecommunications/IT assets and calculate a composite price index through a weighted average approach of the four asset categories. This index, however, is only available from 1983 to 2019. The initial capital stock calculation requires information for the price index prior to 1983. We impute the values of the price index for prior years by using the growth rate of the Handy-Whitman index for the North Atlantic region, adjusted for purchasing power parity ("PPP"),[131] and extrapolate the price index going backwards before 1983. We use this composite price index in place of the Handy-Whitman index for all capital related measurements for HQT. Cost of capital assumptions are also different from that used for the US sample. HQT utilizes a 70% debt and 30% equity. For the cost of debt and equity we use the Régie authorized annual rates for cost of debt and return on equity, provided directly by HQT. HQT are not subject to income taxes and therefore, we do not account for taxes, tax credits, and depreciation deductions. In order to calculate the long-term inflation rate, we use the average annual yield for the 30-year zero-coupon bonds from the Bank of Canada[132] and the Canadian consumer price index ("CPI").[133]

Finally, during the period HQT underwent a material structural change and several accounting changes as discussed in Section II. The material structural change involved the 2008 HQT acquisition of telecommunications assets. Prior to 2008, HQT purchased internal telecommunications services from an HQ supplier and the respective expenses were part of HQT's shared services expenses. The acquisition had two effects on HQT accounts in 2008. First, because of the structural change, O&M expenses decreased materially in 2008, while rate base and capital expenses increased. Second, because HQT was the internal supplier to other HQ entities, it received revenues for these services, which help offset O&M expenses. In addition to this structural change, there were several material accounting changes. In 2009, the Régie put an end to the regulatory practice of retiring depreciated assets through deferral and variance accounts ("DVA"). In 2010, HQT switched from a compound interest depreciation method for property, plant and equipment ("PP&E") to a linear depreciation approach in 2010. In 2012, HQT changed to IFRS accounting standards, and then in 2015 it changed to US GAAP standards. In 2017, HQT filed a request relating to changes in accounting policies involving the provision of retirement benefits.

The structural change and the accounting changes affect HQT total costs, the dependent variable in our econometric cost comparison analysis. Ideally, one would have a series of pro-forma financial data during the period that minimizes the impact of changes in accounting regime and organizational structural. Using pro-forma data ensures that any large changes in MR&S, labor or capital are real

[131] Organization for Economic Co-operation and Development (OECD), Purchasing Power Parities.

[132] Bank of Canada, Yield Curves for Zero-Coupon Bonds.

[133] Statistics Canada. Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted – All Items.

changes and are not the result of accounting changes or changes in organization form. For purposes of the econometric *total* cost comparison, however, using pro-forma financial data is not essential. For example, the HQT purchase of telecom assets results in one-time increases in capital cost and one-time reductions in share expenses so that the net impact on total costs may not be material. In addition, it is not obvious what impact the accounting changes have on HQT total costs. The structural change and accounting changes are more important with respect to an econometric cost comparison of the *capital* or *O&M* expenses. In this case, a sharp increase or decrease in capital or O&M costs that is due to an accounting or structural change could have a material impact of the cost comparison results.[134]

This is also true for using the HQT data to estimate HQT's TFP, as the structural change and the accounting changes could have a significant impact on the growth rates of the different inputs and thus TFP results. Obtaining official, pro-forma financial information would be a challenging exercise for HQT and for purposes of the econometric cost comparison analysis, not likely to be worth the effort. Nevertheless, we performed an unofficial pro-forma adjustment to the HQT financial data for the telecommunication assets and used it as a sensitivity for our econometric cost comparison analysis using the pro-forma adjustment.[135] We did not perform pro-forma adjustments for any of the accounting changes.

B. Econometric analysis

We develop an econometric model that explains the total costs of a utility—the dependent variable—as a function of a set of independent variables that we believe affect a utility's total costs. We use the results from this analysis for two purposes. First, we use the output variables in our TFP study as independent variables in our econometric model. The estimated coefficients on the output variables are the cost elasticities that we use to derive the weights that we use to aggregate the different output measures into one output index in our TFP study. Second, as requested by the Régie, we use the estimated econometric model to compare HQT's cost performance *vis-à-vis* the industry. Specifically, once we estimate our econometric model, we use the model's estimated parameters to predict HQT costs and to compare the predicted costs to HQT actual costs. We calculate a percentage difference and summarize how HQT fares over the period.

[134] From an econometric perspective, one can assume that there are some errors in variables ("EIV") pertaining to the total, capital and O&M cost variables for HQT and for the U.S. sample. Nevertheless, EIV should not present a significant econometric problem because we use total, capital and O&M costs as dependent variables and the disturbance term of a regression model incorporates the errors in measuring the dependent variable. See, Peter Kennedy, *A Guide to Econometrics*, MIT Press Third Edition, 1992, p. 136.

[135] Specifically, we assume the acquisition occurred at the beginning of the period instead of 2008 and adjust shared expenses, PP&E, and accumulated depreciation prior to 2008. We use the one-time changes in 2008 in shared expenses, PP&E and accumulated expenses as the basis for making changes to the years prior to 2008. Using the pro-forma financial data for the econometric cost comparison analysis below did not change any of our conclusions. That is, our cost comparison conclusions below are robust to the use of the pro-forma data.

Econometrics is the use of statistical methods for estimating economic relationships, in our case the relationship between a company's total costs and its output and operating characteristics. Econometric analysis involves a dependent variable that is the variable that is being "explained" in the model—in our case total costs—and a set of independent variables, the variables that are the "explanatory" variables. The dependent variable is a variable that we estimate a relationship for, whose value depends on a set of external variables. The independent variables help define the relationship and form the basis on which we model the dependent variable.

For our econometric cost comparison analysis, the dependent variable is total costs—*i.e.*, labor, MR&S and capital expenses—and the independent variables are a set of variables that we have data on and that we believe has a material impact on total costs. Table 13 presents the variables we use for our econometric cost benchmarking analysis.

TABLE 13: VARIABLES FOR ECONOMETRIC BENCHMARKING

Category	Description	*Unit*
Dependent Variable	Total Real Input Costs	
Output Quantity Metrics	Length of Tranmission Lines Ratcheted Peak Demand Total Energy Output	*km* *MW* *MWh*
Control Variables	% of Transmission Plant in Electric Plant Average Substation Capacity Substation count per line km of transmission line Average Voltage of transmission lines % of transmission lines that are underground	*%* *MVA* *units/km* *kV* *%*

Notes:
1) The dependent variable is the total real cost, defined as the ratio of the total nominal input costs and the combined input price index.
2) The output metrics and the control variables, together, are called the "independent variables" in a regression model.

For our analysis, the dependent variable is the total cost of inputs—specifically, the total *real* cost of inputs. To arrive at total real costs, we divide labor, MR&S and capital costs by our input price index. We then regress total real costs on the three output quantity metrics as well as certain control variables, which together make up the set of independent variables.

We use the same output metrics as we used in our TFP study with the exception that for peak demand we use ratcheted peak demand.[136] Ratcheted peak demand for a given year is the maximum value of peak demand observed since the beginning of the study period up to that year. For example, the ratcheted peak demand for 1995 is the maximum of the peak demand for 1994 and 1995. Similarly, the ratcheted peak demand for 2014 is the maximum peak demand observed over the 1994-2014 period. We believe ratcheted peak demand is a more correct output variable for an econometric model of transmission costs than peak demand because an increase in peak demand in a given year may not necessarily result in capacity additions and additional costs. If the existing capacity is sufficient, an increase in peak demand may not require additional investments. On the other hand, it is more likely that an increase in ratcheted peak demand will require capacity additions and result in additional costs.

Control variables are other variables that we believe are determinants of total costs. We include them in the regression models in order to accurately isolate the effect of the output quantities on total costs in order to specify the model as best as possible, given data constraints. In our model, we include five control variables. The first is the percentage of transmission electric plant, which is the ratio of the gross transmission plant[137] in service to the total electric plant in service.[138] The four remaining control variables[139] are in FERC Form 1 but SNL does not process them. For these variables, we processed the raw FERC Form 1 files released by the FERC in a statistical software. Average substation capacity[140] is a simple average of the capacities of all the substations owned by a transmission company. Substation count per kilometer of transmission line is the ratio of the total substation count[141] to the total length of transmission lines. Average voltage of transmission lines,[142] like substation capacity, is the simple average of the voltage of all transmission lines owned by a company. While a more accurate way to measure this is the weighted average voltage, weighted by the length of respective transmission lines, this would be a tedious exercise given the format of the raw FERC data. More importantly, the simple average is likely highly correlated with the weighted average of transmission line voltage, and therefore it serves as a reasonable proxy to include in the regression model. Underground transmission lines[143] are more expensive to maintain than those built on land and is therefore included as a percentage of the total transmission line length in order to normalize for the varying sizes of companies included in the sample.

136 For transmission length, for the U.S. sample we convert miles of transmission lines to kilometers in the econometric benchmarking analysis. This conversion would have no effect on the TFP growth calculations but it is important to use the same standard in the econometric cost comparison analysis, where absolute measures are used.

137 FERC Form 1, page 207, line 58, column g, account 359.1

138 FERC Form 1, page 207, line 104, column g.

139 Raw FERC Form 1 data is available on the [FERC website.]

140 FERC Form 1, page 426, column f.

141 FERC Form 1, page 426.

142 FERC Form 1, page 422, column c.

143 We calculate this metric using the information on transmission lines in FERC Form 1, page 422, column e.

Our primary dataset for this analysis consists of repeated observations of the variables in Table 13 for a group of companies over time. Such a dataset that tracks the same set of entities over time is a panel dataset.[144] Accounting for the panel nature of the dataset is important because there may be certain unobservable cost characteristics that are specific to companies that drive their transmission activities and costs. Failure to account for these features of the dataset and treating each observation as an independent observation can lead to an "omitted variable bias" problem. Relatedly, unlike the TFP analysis, panel data estimation does not require an observation for a given company for every single year. Panel data estimators can account for the effect of the independent variables over the period for which data is available. For the sake of consistency, however, we consider the same set of companies from the TFP study for the benchmarking analysis.

We consider two common estimators to deal with panel dataset—the fixed effects ("FE") estimator and random effects ("RE") estimator. FE assumes that the unobservable company-specific variables are related to one or more of the model's independent variables and failure to control for them could bias the parameter estimates. Therefore, it removes the unobserved effect from the error term prior to model estimation using a data transformation process.[145] During this process, other independent variables that are constant over time are also removed meaning that the FE estimation cannot estimate the impact of variables that remain constant over time. The benefit, however, of FE is that it controls for company-specific factors that are not observable but that remain constant over time. One key example is the geographic territory, climate and the difficulty or ease of providing transmission services. RE is a reasonable alternative to FE when a researcher is able to explicitly control for all potential independent variables and has a good reason to think that any unobservable variable is not correlated with any of the model's independent variables. An advantage of the RE estimator is that it allows for the estimation of variables that remain constant over time.

The decision to use the fixed effects or the random effects estimator depends on the underlying characteristics of the data and the model specification. A statistical test, performed after estimating the FE and RE models, known as the "Hausman test", helps assess whether the FE or RE estimator is more appropriate for a given panel dataset and model specification. In our specifications, the Hausman test generally led to the conclusion that the FE model was preferred and so we base our econometric cost comparison analysis on the FE results.[146] The use of the ratcheted peak demand variable, however, complicates the interpretation of results from the fixed effects regression. This is because the ratcheted peak demand for most companies can show little variation over time or can be constant—if a company

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144 For a discussion on panel data, *see* Jeffrey M. Wooldridge, *Econometric Analysis of Cross Section and Panel Data,* 1st Edition, (MIT Press), October 1, 2001. *See also* William H. Greene, *Econometric Analysis,* 5th Edition, (Prentice Hall) September 1, 2002.

145 Specifically, for each variable and each company, the FE estimator subtracts the mean value from each observation and applies ordinary least squares to these transformed data. The FE estimator thus removes and controls for all unobservable company effects that remain constant over time, ensuring the remaining coefficients are not biased.

146 Nevertheless, as a sensitivity we performed the cost comparison analysis using the RE model and results and reached similar conclusions. That is, our cost comparison conclusions below are robust to the use of the RE estimator.

experienced the highest peak demand earlier in the sample period, the ratcheted demand can potentially stay constant over time. Therefore, for purposes of determining the TFP weights for the output metrics, we adopt the random effects estimator because under RE the effect of the ratcheted peak demand can be measured even if it stays constant over time.[147]

The regression specification we employ uses a logarithmic functional form. In this model, we express the dependent variable and the three output metrics in natural logarithms, which is common practice in econometric literature. The final regression specification is as follows:

$$\begin{aligned}\ln Real\ Cost = {} & \beta_o + \beta_1 \ln(TxLine) + \beta_2 \ln(RatchetedPeak) + \beta_3(TotalEnergy) \\ & + \beta_4(\textit{\% Tx Plant}) + \beta_5(Subs\ per\ line\ km) + \beta_6(Avg.\ Tx\ Line\ Voltage) + \beta_7(\%\ Tx\ line\ underground) \\ & + \beta_8(Time\ Trend) + \varepsilon_{it}\end{aligned} \tag{35}$$

The time trend is a variable that indicates the cumulative impact of those factors that change over time and impact total costs. It is equal to one for the year 1994 and increases by one for every subsequent year. The use of a time trend accounts for other external factors that change with time, such as technological progress, that may have an effect on total costs. We also tested specifications that included quadratic forms (squared terms) of the output metrics, as well as interactions but these did not yield conclusive results. The use of natural logarithms allows us to interpret the coefficients of the output metrics as *elasticities*—the percentage change in total costs from a 1% increase/decrease in an output metric. In order to arrive at the TFP weights, we take the relative proportion of the coefficients for each output metric. In other words:

$$Weight_i = \frac{Elasticity_i}{\sum_{i=1}^{3} Elasticity_i} \tag{36}$$

Where i represents each output metric.

C. Total cost comparison analysis

Table 14 presents the coefficient estimates for the final regression models. We use model (3) for our cost comparison analysis and model (2) for the output weights in our TFP model. Model (2) implies: a 1% increase in transmission line length, increases total real costs by 0.30%; a 1% increase in ratcheted peak demand, increases total real costs by 0.39%; a 1% increase in total energy output, increases total real costs by 0.05%, but is statistically insignificant. This implies TFP weights of approximately 40% for transmission line length and 60% for peak demand.

[147] Use of the FE model for determining the weights would result in giving less weight to peak demand—which has grown the fastest over the period—and more weight to miles of transmission lines, compared to our base case, thus resulting in somewhat slower TFP growth. As discussed in the sensitivity section of our TFP results, however, the output weight does not have a large impact on the TFP results.

TABLE 14: REGRESSION RESULTS REAL TOTAL COSTS

VARIABLES	Unit	(1) Fixed Effects - US Sample	(2) Random Effects - US Sample	(3) Fixed Effects - US Sample + HQT	(4) Random Effects - US Sample + HQT
Length of Transmission Line	*km*	0.255**	0.297***	0.255**	0.303***
		(0.0318)	(0.000969)	(0.0319)	(0.000875)
Ratcheted Peak Demand	*MW*	0.161	0.387***	0.162	0.413***
		(0.490)	(0.00215)	(0.487)	(0.00147)
Total Energy Output	*MWh*	0.0528	0.0515	0.0522	0.0530
		(0.532)	(0.540)	(0.535)	(0.527)
% of Transmission Plant in Electric Plant	*%*	0.929**	0.989**	0.931**	1.013**
		(0.0311)	(0.0145)	(0.0302)	(0.0121)
Substation count per line km	*count/km*	1.459	2.055	1.463	2.115
		(0.342)	(0.109)	(0.341)	(0.101)
Average Voltage of Transmission Lines	*kV*	0.000189	0.000224	0.000191	0.000286
		(0.735)	(0.679)	(0.732)	(0.604)
% of Transmission lines underground	*%*	3.309	3.280**	3.311	3.206**
		(0.211)	(0.0156)	(0.211)	(0.0219)
Avg. Substation Capacity	*MVa*	2.50e-05	3.76e-05	2.59e-05	3.74e-05
		(0.835)	(0.754)	(0.829)	(0.754)
Time Trend		0.0140***	0.0106***	0.0139***	0.0101***
		(0.00129)	(0.000736)	(0.00126)	(0.00135)
Constant		13.23***	11.08***	13.25***	10.80***
		(2.29e-08)	(0)	(2.23e-08)	(0)
Observations		1,864	1,864	1,883	1,883
R-squared		0.441		0.441	
Number of Companies		74	74	75	75
R sq. within		0.441	0.436	0.441	0.435
R sq. between		0.793	0.824	0.804	0.836
R sq. overall		0.747	0.790	0.758	0.803
Adjusted R sq.		0.438		0.438	
F Statistic		9.913***		9.960***	
Chi^2 Statistic			211		205.3

Note: Robust p-value in parentheses. *** p<0.01, ** p<0.05, * p<0.1

Our econometric cost comparison analysis utilizes the results from the estimated total cost model to predict costs for each company. This is also known as an "in-sample" estimate of costs—costs are predicted for the dependent variable using the same set of data that we used to estimate the model. Specifically, we predict total costs for HQT using model (3) from Table 14 above.[148] We then compare the predicted costs to the actual costs as per the following formula, to provide a measure of cost performance.

[148] As mentioned, while we use the fixed-effects estimator for the results below (model (3)), our conclusions are generally robust to the use of the random-effects estimator.

$$\% \, Difference \ in \ costs = ln\left(\frac{Actual \ Costs}{Predicted \ Costs}\right) \tag{37}$$

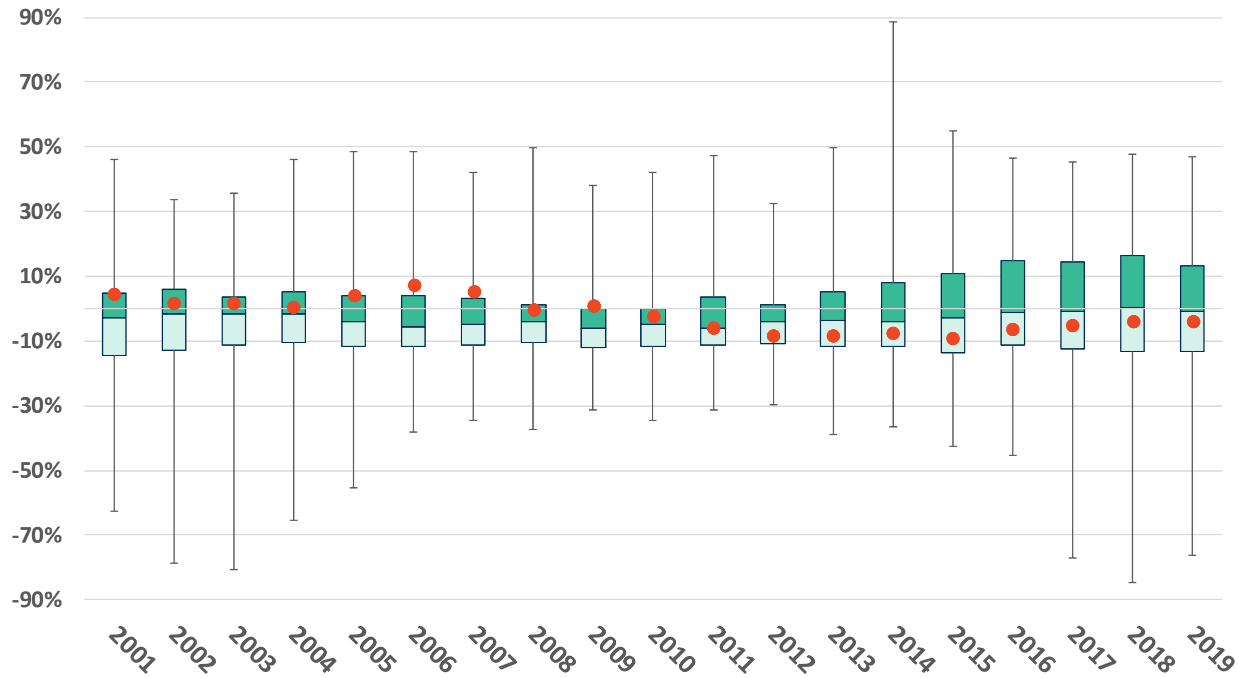
In Table 15, we present the results from our total cost benchmarking analysis for HQT, with a negative value indicating lower costs than those predicted by the model and a positive value indicating higher costs than those predicted by the model. Over the entire period, HQT's percent difference in costs was -1.7%, compared to the mean value of -2.3% for the entire sample of U.S. companies. HQT's cost efficiency improved in more recent periods, -2.8% between 2005 and 2019—compared to -1.9% mean value for the U.S. sample—and -6.0% between 2010 and 2019—compared to -1.0% mean value for the U.S. sample. In Table 15, we also provide information on the best and worst performers in the sample for each year, as well as HQT's percentile ranking in the last column. For example, in 2019 HQT's 57 percentile means that 43 percent of companies had superior cost performance.

TABLE 15: TOTAL COST BENCHMARKING RESULT FOR HQT

	HQT	Full Sample of Utilities			
Year	% Difference (Fixed Effects)	Mean % Difference (Fixed Effects)	Min % Difference (Fixed Effects)	Max % Difference (Fixed Effects)	HQT Percentile (Fixed Effects)
2001	4.4%	-4.3%	-62.7%	46.3%	26%
2002	2.0%	-4.5%	-78.7%	33.7%	32%
2003	1.9%	-4.8%	-80.8%	35.6%	31%
2004	0.8%	-2.8%	-65.3%	45.9%	38%
2005	4.2%	-2.9%	-55.3%	48.7%	24%
2006	7.5%	-3.6%	-38.3%	48.5%	19%
2007	5.6%	-3.9%	-34.5%	42.3%	17%
2008	-0.2%	-3.5%	-37.5%	49.9%	33%
2009	0.8%	-4.2%	-31.4%	38.1%	24%
2010	-2.4%	-4.1%	-34.7%	42.1%	35%
2011	-5.9%	-3.7%	-31.3%	47.2%	51%
2012	-8.3%	-3.8%	-29.5%	32.3%	68%
2013	-8.1%	-2.2%	-38.8%	49.7%	62%
2014	-7.4%	0.6%	-36.4%	88.8%	64%
2015	-9.1%	0.5%	-42.7%	55.0%	69%
2016	-6.1%	1.1%	-45.5%	46.6%	59%
2017	-4.9%	0.5%	-77.1%	45.5%	59%
2018	-3.7%	1.7%	-84.7%	47.9%	62%
2019	-3.7%	-0.2%	-76.1%	47.0%	57%
2001 - 2019	***-1.7%***	***-2.3%***	***-51.6%***	***46.9%***	***41%***
2005 - 2019	***-2.8%***	***-1.9%***	***-46.3%***	***48.6%***	***47%***
2010 - 2019	***-6.0%***	***-1.0%***	***-49.7%***	***50.2%***	***52%***

We provide an alternative representation and summary of HQT's performance relative to the rest of the sample of U.S. companies. The box plot in Figure 1 below provides a graphical distribution of the percentage difference in costs for each year. HQT's cost performance for each year is within a tight range of -/+ 10% and is close to the median for most years.

FIGURE 1: PERCENTAGE DIFFERENCE BETWEEN ACTUAL AND PREDICTED TOTAL COSTS



Note: The box-plot represents the 25th to 75th percentile of the distribution. The error bars on either side indicate the minimum and maximum of the distribution.

D. Capital cost comparison analysis

As requested by the Régie, we repeat our econometric cost comparison analysis above but instead of using total costs we focus only on capital costs. Specifically, in Table 16 below, we present the results of our econometric analysis where our dependent variable is capital costs, rather than total costs. We do not use these results for the cost weighting of our TFP study.

TABLE 16: REGRESSION RESULTS FOR CAPITAL COST ECONOMETRIC MODEL

VARIABLES	Unit	(1) Fixed Effects - US Sample	(2) Random Effects - US Sample	(3) Fixed Effects - US Sample + HQT	(4) Random Effects - US Sample + HQT
Length of Transmission Line	*km*	0.112	0.210**	0.112	0.211**
		(0.179)	(0.0201)	(0.177)	(0.0219)
Ratcheted Peak Demand	*MW*	0.0604	0.382***	0.0582	0.398***
		(0.724)	(9.62e-05)	(0.734)	(0.000149)
Total Energy Output	*MWh*	0.0887*	0.0849	0.0894*	0.0878*
		(0.0966)	(0.103)	(0.0948)	(0.0952)
% of Transmission Plant in Electric Plant	*%*	1.725***	1.769***	1.718***	1.783***
		(6.20e-07)	(6.56e-09)	(6.34e-07)	(4.76e-09)
Substation count per line km	*count/km*	4.005***	4.706***	4.000***	4.754***
		(0.000436)	(5.43e-05)	(0.000442)	(5.52e-05)
Average Voltage of Transmission Lines	*kV*	0.000315	0.000402	0.000314	0.000451
		(0.432)	(0.333)	(0.434)	(0.289)
% of Transmission lines underground	*%*	3.818**	2.694***	3.819**	2.693***
		(0.0135)	(0.00126)	(0.0135)	(0.00226)
Avg. Substation Capacity	*MVa*	0.000205***	0.000225***	0.000204***	0.000223***
		(0.00832)	(0.00200)	(0.00886)	(0.00202)
Time Trend		0.00136	-0.00321	0.00148	-0.00339
		(0.666)	(0.158)	(0.638)	(0.140)
Constant		14.06***	10.73***	14.09***	10.56***
		(0)	(0)	(0)	(0)
Observations		1,861	1,861	1,880	1,880
R-squared		0.356		0.356	
Number of Companies		74	74	75	75
R sq. within		0.356	0.333	0.356	0.332
R sq. between		0.433	0.817	0.455	0.830
R sq. overall		0.436	0.799	0.453	0.812
Adjusted R sq.		0.353		0.353	
F Statistic		12.71***		12.72***	
Chi^2 Statistic			197.7		182.7

Note: Robust p-value in parentheses. *** p<0.01, ** p<0.05, * p<0.1

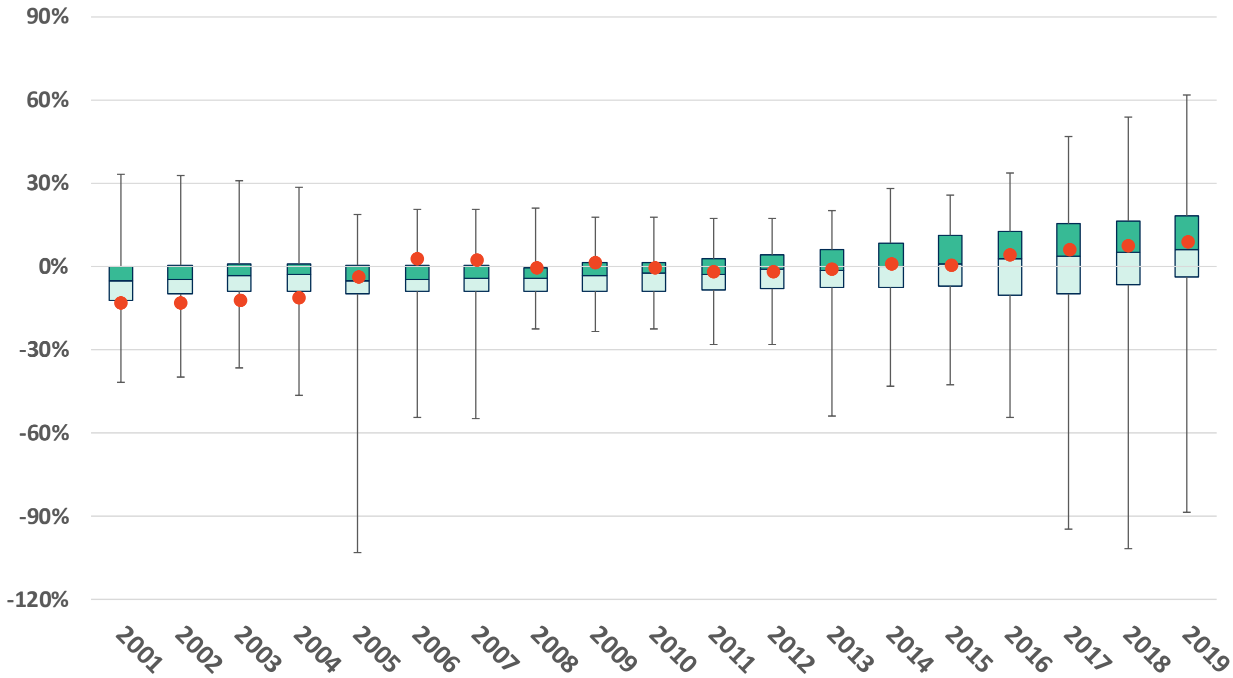
In Table 17, we present the results from the capital cost benchmarking analysis for HQT. Over the entire period, HQT's actual costs averaged -1.1% lower than its predicted costs, compared to the mean value of -2.2% for the entire sample of U.S. companies. HQT's cost efficiency seems to show slightly less improvement throughout the period compared to the entire sample of companies but remains within a tight range implying that the actual costs are very similar to those predicted by the model.

TABLE 17: CAPITAL COST BENCHMARKING RESULTS FOR HQT

	HQT	Full Sample of Utilities			
Year	% Difference (Fixed Effects)	Mean % Difference (Fixed Effects)	Min % Difference (Fixed Effects)	Max % Difference (Fixed Effects)	HQT Percentile (Fixed Effects)
2001	-12.9%	-5.6%	-41.5%	33.1%	79%
2002	-12.9%	-4.7%	-39.7%	32.6%	85%
2003	-12.1%	-3.7%	-36.7%	30.8%	86%
2004	-10.9%	-4.0%	-46.4%	28.4%	85%
2005	-3.4%	-6.7%	-102.8%	18.6%	42%
2006	2.8%	-5.0%	-54.4%	20.4%	16%
2007	2.5%	-4.8%	-54.8%	20.6%	17%
2008	-0.4%	-4.2%	-22.3%	21.0%	25%
2009	1.8%	-3.7%	-23.4%	17.9%	23%
2010	-0.1%	-3.4%	-22.7%	17.5%	33%
2011	-1.6%	-3.4%	-28.0%	17.3%	43%
2012	-1.8%	-2.2%	-28.0%	17.4%	56%
2013	-0.7%	-2.1%	-53.8%	20.0%	49%
2014	1.2%	-0.8%	-43.0%	28.1%	45%
2015	0.7%	0.9%	-42.8%	25.8%	52%
2016	4.4%	1.4%	-54.5%	33.7%	45%
2017	6.3%	2.2%	-94.4%	46.9%	45%
2018	7.5%	3.2%	-101.6%	53.6%	44%
2019	9.1%	5.5%	-88.6%	61.9%	44%
2001 - 2019	***-1.1%***	***-2.2%***	***-51.6%***	***28.7%***	***43%***
2005 - 2019	***1.9%***	***-1.5%***	***-54.3%***	***28.1%***	***30%***
2010 - 2019	***2.5%***	***0.1%***	***-55.8%***	***32.2%***	***37%***

The box plot in Figure 2 below provides a graphical distribution of the percentage difference in capital costs for each year.

FIGURE 2: PERCENTAGE DIFFERENCE BETWEEN ACTUAL AND PREDICTED CAPITAL COSTS



Note: The box-plot represents the 25th to 75th percentile of the distribution. The error bars on either side indicate the minimum and maximum of the distribution.

E. O&M cost comparison analysis

We also perform the cost benchmarking analysis for O&M expenses. The approach follows that used for the total costs and capital costs, except that the dependent variable in the econometric model is the total real O&M expense.[149] Table 18 presents the regression results for the O&M econometric model while Table 19 summarizes the results for the O&M benchmarking analysis.

[149] The real expense for a given utility is defined as the nominal O&M costs for that utility deflated by the composite price index for labor and MRS, which make up the O&M expenses.

TABLE 18: REGRESSION RESULTS FOR O&M COST ECONOMETRIC MODEL

VARIABLES	Unit	(1) Fixed Effects - US Sample	(2) Random Effects - US Sample	(3) Fixed Effects - US Sample + HQT	(4) Random Effects - US Sample + HQT
Length of Transmission Line	*km*	0.216	0.238*	0.215	0.246*
		(0.212)	(0.0582)	(0.216)	(0.0513)
Ratcheted Peak Demand	*MW*	0.223	0.385*	0.233	0.420**
		(0.550)	(0.0589)	(0.533)	(0.0390)
Total Energy Output	*MWh*	0.0559	0.0587	0.0514	0.0577
		(0.742)	(0.735)	(0.760)	(0.737)
% of Transmission Plant in Electric Plant	*%*	-0.978	-0.887	-0.951	-0.825
		(0.329)	(0.345)	(0.341)	(0.378)
Substation count per line km	*count/km*	-5.287*	-3.569	-5.257*	-3.436
		(0.0743)	(0.202)	(0.0768)	(0.222)
Average Voltage of Transmission Lines	*kV*	3.10e-05	0.000144	4.37e-05	0.000239
		(0.975)	(0.877)	(0.965)	(0.799)
% of Transmission lines underground	*%*	0.664	3.426*	0.674	3.338*
		(0.892)	(0.0892)	(0.891)	(0.0967)
Avg. Substation Capacity	*MVa*	-0.000203	-0.000195	-0.000196	-0.000191
		(0.472)	(0.484)	(0.491)	(0.494)
Time Trend		0.0459***	0.0430***	0.0453***	0.0419***
		(8.64e-07)	(0)	(1.03e-06)	(8.93e-11)
Constant		12.01***	10.37***	12.03***	10.04***
		(0.000136)	(1.14e-08)	(0.000137)	(2.02e-08)
Observations		1,864	1,864	1,883	1,883
R-squared		0.414		0.410	
Number of Companies		74	74	75	75
R sq. within		0.414	0.411	0.410	0.407
R sq. between		0.305	0.492	0.360	0.535
R sq. overall		0.334	0.464	0.363	0.493
Adjusted R sq.		0.411		0.408	
F Statistic		15.43***		15.29***	
Chi^2 Statistic			253.9		266.3

Note: Robust p-value in parentheses. *** p<0.01, ** p<0.05, * p<0.1

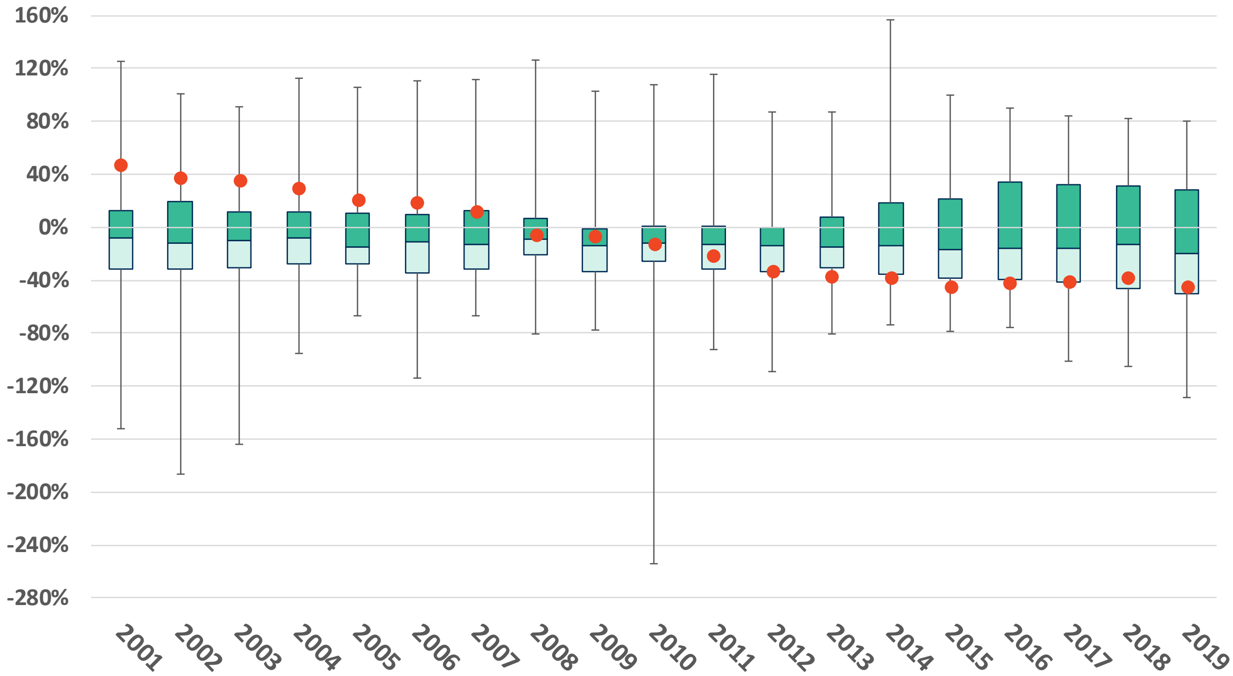
Over the entire period, HQT's O&M costs were 8.5% lower than those predicted by the econometric model. This is almost equal to the average for the entire sample of U.S. companies at -8.2% and lies within the -/+ 10% range. HQT has exhibited improved O&M cost performance. For the most recent ten-year period, HQT's cost were 35.2% lower than the predicted costs compared to an average of -8.8% for the entire sample. Relatedly, only 32% percent of the companies fared better than HQT over the same period compared to 61% of companies with better cost performance over the entire twenty-year period.

TABLE 19: O&M COST BENCHMARKING RESULTS FOR HQT

	HQT	Full Sample of Utilities			
Year	% Difference (Fixed Effects)	Mean % Difference (Fixed Effects)	Min % Difference (Fixed Effects)	Max % Difference (Fixed Effects)	HQT Percentile (Fixed Effects)
2001	47.1%	-7.4%	-152.3%	125.7%	13%
2002	37.4%	-11.1%	-186.8%	100.4%	13%
2003	35.8%	-12.8%	-164.1%	90.5%	10%
2004	29.3%	-4.9%	-94.9%	112.1%	15%
2005	21.3%	-2.6%	-66.6%	105.5%	20%
2006	18.5%	-7.0%	-113.9%	110.8%	18%
2007	12.5%	-6.4%	-67.0%	111.3%	24%
2008	-5.8%	-4.3%	-80.4%	126.1%	43%
2009	-6.4%	-11.4%	-78.2%	102.5%	36%
2010	-12.6%	-12.2%	-253.9%	107.7%	52%
2011	-21.0%	-10.2%	-92.4%	115.5%	65%
2012	-33.3%	-11.9%	-108.8%	87.2%	77%
2013	-36.7%	-8.0%	-81.0%	86.7%	85%
2014	-37.6%	-3.8%	-73.6%	157.0%	80%
2015	-44.5%	-5.7%	-79.0%	99.8%	88%
2016	-41.8%	-4.9%	-75.8%	89.8%	78%
2017	-40.7%	-7.4%	-100.9%	83.8%	76%
2018	-38.3%	-8.0%	-104.8%	82.4%	68%
2019	-45.0%	-16.1%	-128.7%	80.0%	73%
2001 - 2019	***-8.5%***	***-8.2%***	***-110.7%***	***103.9%***	***39%***
2005 - 2019	***-20.8%***	***-8.0%***	***-100.3%***	***103.1%***	***59%***
2010 - 2019	***-35.2%***	***-8.8%***	***-109.9%***	***99.0%***	***68%***

The box plot in Figure 3 below provides a graphical distribution of the percentage difference in costs for each year and shows the improvement made over time.

FIGURE 3: PERCENTAGE DIFFERENCE BETWEEN ACTUAL AND PREDICTED O&M COSTS



Note: The box-plot represents the 25th to 75th percentile of the distribution. The error bars on either side indicate the minimum and maximum of the distribution.

VIII. MRI Recommendations

A. Long-run industry TFP growth

TFP growth is the key component of the X-factor in a MRI plan. In Section VI, we presented our TFP growth results for the U.S. sample of transmission utilities under different periods between 1994 and 2019, and under different assumptions.

For purposes of the X-factor, our base case TFP growth rate is over the entire period 1994 to 2019. Our base case results for TFP growth rate for the U.S. sample of transmission utilities for the period 1994 to 2019 is -1.04%—see results in Table 11 above. In terms of partial factor productivity, capital PFP and O&M PFP growth were -0.05% and -3.38%, respectively between 1994 and 2019.

B. Inclusion of capital in the MRI

As discussed in Section II, the current MRI applies only to certain O&M expenses and does not apply to HQT's capital expenses. The Régie requested that experts provide a "pros and cons" of including capital in the MRI. The manner in which a firm moves from cost-of-service regulation to PBR regulation depends upon the ultimate goals and objectives of the regulatory authority. It also depends on the trade-offs between increased incentives to operate efficiently and protections to both shareholders and consumers from the uncertainties involved in a move to PBR.

In Table 20, we summarize the "pros" and "cons" of including or not including capital in the MRI. As can be seen, the tradeoff is one between more incentives to operate efficiently versus the potential impact on reliability, redundancy and overall service quality.

TABLE 20: PROS AND CONS OF INCLUDING CAPITAL IN THE MRI

Include capital in the MRI	"Pros"	"Cons"
Yes	Results in *improved* efficiency incentives as there are no costs that are under a cost-of-service methodology; cost minimization incentive applies to both O&M and Capital and ensures that O&M-Capital substitution will be optimal and reflect the marginal product of O&M and capital.	Risk that the MRI formula will be insufficient to fund certain large capital expenditures that are essential to reliability, redundancy and overall service quality.
No	Company has opportunity to recover all prudently incurred, used and useful investments under the cost-of-service regime and thus not potentially negatively impacting reliability, redundancy and overall service quality.	Results in *less* efficiency incentives as a large component of the company's costs continue to be under a cost of service methodology; cost minimization incentive applies only to O&M and not Capital increasing the likelihood of inefficient O&M-Capital substitution.

Source: Authors' Construct.

C. X-factor

As discussed in Section III, the selection of the inflation measure (I) in a price and revenue cap formula has direct implications regarding the X-factor. The inflation factor can measure *input prices* that reflect the input inflation growth that a firm is likely to experience. The Inflation factor in the current MRI appears to serve this purpose. Alternatively, the inflation factor can measure economy-wide *output* prices—*e.g.*, GDP-PI. Below we discuss the difference under the two scenarios and the implied X-factors.

1. Inflation factor: input prices

When the inflation factor in the I-X formula measures *input price* inflation and reflects the growth in input prices that a firm is likely to experience during the life of the plan, the appropriate X-factor is the TFP growth of the industry. The inflation factor in the current MRI represents the growth in the wages and labor expenses that HQT likely faces in its geographic territory—as measured by the average growth rate of the weekly earnings of Quebec employees—as well as the growth in input prices HQT pays for non-labor purchases—as measured by CPI-Québec. While the current MRI plan does not include capital expenses—and the updated MRI plan may eventually include capital—there is regulatory precedence for using the CPI index as a proxy for changes in non-labor input prices, including capital.[150]

[150] Alberta Utilities Commission Decision 2012-237, p. 44, using the CPI for Alberta as the non-labor inflation factor in the first generation PBR plan.

Therefore, if the inflation factor in the current MRI plan continues in use, based upon our results in this study we recommend an X-factor of -1.04% for a revenue cap that applies to both O&M and capital expenses and an X-factor of -3.38% for a revenue cap that applies to O&M only.

2. Inflation factor: output prices

The other possibility is when the inflation factor in the I-X formula measures *output price* inflation, such as the economy-wide measure GDP-PI. In this case, as elaborated in Section III, the appropriate X-factor is not just the TFP growth of the industry. Rather, it is the difference in total factor productivity growth rates between the regulated firm and the rest of the economy ($\dot{T} - \dot{T}^E$) plus the difference, if any, in the input price growth rates between the rest of the economy and the regulated firm ($\dot{W}^E - \dot{W}$).

In Table 21 below, we present the X-factor when the economy-wide output price measure of inflation is the Canadian GDP-PI. We observe that Canadian TFP growth has surpassed the industry TFP in every period. We also observe that for all periods, with the exception of the most recent period, Canadian input prices have grown at slower rates than the industry. In the table below, we calculate an X-factor of -2.82% for the entire period.

TABLE 21: X-FACTOR BASED ON CANADIAN ECONOMY WIDE INFLATION

Year [A]	Transmission TFP [B]	Canadian TFP [C]	Transmission Input Price [D]	Canadian Input Price [E]	X-Factor [F]
1995 - 2019	-1.04%	0.22%	3.55%	1.99%	-2.82%
2000 - 2019	-1.50%	0.10%	3.23%	1.98%	-2.85%
2005 - 2019	-1.69%	-0.03%	3.54%	1.79%	-3.42%
2010 - 2019	-1.97%	0.68%	1.47%	2.36%	-1.76%

Sources and Notes:
[B]: Authors' TFP Model
[C]: Statistics Canada. Table 36-10-0208-01 Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by industry
[D]: Author's TFP Model
[E]: The Canadian input price growth is defined as the sum of the growths of the Canadian TFP and the GDP-PI.
[F] = ([B] – [C]) + ([E] – [D]).

3. Summary

Table 22 below summarizes our X-factor recommendations, based upon what measure of inflation is in the PBR plan. Under the current input-price inflation measure, we recommend an X-factor of -1.04%. If the PBR plan adopts an economy-wide output price inflation, such as GDP-PI, we recommend an X-factor of -2.82%.

TABLE 22: X-FACTOR RECOMMENDATIONS BY TYPE OF INFLATION IN THE MRI PLAN

Year	*Input Price* Inflation	Economy-wide *Output Price* Inflation
1995-2019	-1.04%	-2.82%

Source: Authors' TFP Model.

Table 23**Error! Reference source not found.** below summarizes our recommendations on the X-factor when the inflation measure is an input price inflation and depending on whether the MRI applies to total costs or continues to apply to O&M only. If the plan will apply to total costs, we recommend an X-factor of -1.04%. If the plan will apply to O&M only, we recommend an X-factor of -3.38%.

TABLE 23: X-FACTOR RECOMMENDATIONS BY TYPE OF COSTS IN THE MRI PLAN

Year	*MRI Plan applies to Total Costs*	*MRI Plan applies to O&M Only*
1995-2019	-1.04%	-3.38%

Sources and Notes: Authors' TFP Model.
1) X-factor of -1.04% is based on the industry-wide TFP growth.
2) X-factor of -3.38% is based on the industry-wide O&M PFP growth.

D. Stretch factor

The selection of a stretch factor ultimately depends upon regulatory judgement, even when an analytical approach like the econometric cost comparison is used because converting results to specific stretch factors lacks a theoretically and empirically robust methodology and ultimately requires judgement. The Régie has requested the experts in this proceeding to conduct a total cost benchmarking or an econometric cost comparison analysis in order to assist it in selecting a stretch factor. We conducted an econometric cost comparison analysis and described our methodology, model and results in Section VII. That analysis shows that HQT's costs tended to be fairly close to the costs predicted by the econometric model.

As we stated in Section III, however, we caution against mechanical use of econometric cost comparison analysis for setting the stretch factor, as it cannot be a complete substitute for what we believe is ultimately an exercise based on judgement as well as regulatory precedence. As mentioned, a robust methodology connecting the results of the cost comparison and the stretch factor is lacking and the analysis relies on econometric estimates of cost models the results of which can be very sensitive to assumptions, specifications and estimators used. Part of that judgement and regulatory prudence involves examining and giving weight to past regulatory decisions on the stretch factor adopted by regulators for a transmission or electricity distribution PBR plan. In Section III, we summarized recent North American stretch factor decisions in electricity transmission and distribution PBR plans and found them to range from 0.10 to 0.30 percent.

Based upon our analysis, we believe that 0.10 to 0.30 percent is a reasonable range for the S-factor for an MRI plan that resets the X-factor in year four of the plan or in a plan and that could apply to both HQT's operating expenses as well as its capital expenses.

Appendix I – FERC Company Data

Company Name	Included in sample	Notes
AEP Texas Central Company	No	AEP Texas Central Company and AEP Texas North Company merged into AEP Texas in 2016. After 2016, data is no longer reported separately for these two companies. Data for AEP Texas (the merged company) is reported after 2016, but it is missing system peak data for 2017-2019.
AEP Texas North Company	No	See notes for AEP Texas Central Company.
Alabama Power Company	Yes	Dataset complete.
Alaska Electric Light and Power Company	No	FERC Form 1 unavailable from 1988 to 1993.
ALLETE (Minnesota Power)	Yes	Dataset complete.
Ameren Illinois Company	No	In 2010, Ameren's three Illinois operating companies merged to become Ameren Illinois Company. Ameren Illinois Company started filing FERC Form 1 after 2010, but there is no data available before 2010.
Appalachian Power Company	No	The company reported negative O&M costs in 2009. Also, total energy data is not available in 2001.
Arizona Public Service Company	Yes	Dataset complete.
Atlantic City Electric Company	Yes	Dataset complete.
Avista Corporation	Yes	Dataset complete.
Baltimore Gas and Electric Company	Yes	Transmission line length for 1996 not available. Imputed value based on the average transmission line length between 1995 and 1997.
Black Hills Colorado Electric, Inc.	No	Data not available before 2008.
Black Hills Power, Inc.	Yes	Dataset complete.
Central Hudson Gas & Electric Corporation	Yes	Dataset complete.
Central Maine Power Company	Yes	Dataset complete.
Cheyenne Light, Fuel and Power Company	No	Data not available before 2003.
Cleco Power LLC	Yes	Dataset complete.

Cleveland Electric Illuminating Company	Yes	In 2014 and 2016, the company's reporting of the length of transmission lines was inconsistent with other years. We deduced the numbers for the two years using data from other years and data on transmission lines added in a given year.
Commonwealth Edison Company	Yes	Large jump in O&M costs in 2004. However, we retained this company since there is no clear reason to adjust the O&M.
Connecticut Light and Power Company	Yes	Dataset complete.
Consolidated Edison Company of New York, Inc.	Yes	Large jump in labor costs in 2002. However, we retained this company since there is no clear reason to adjust the Labor. Transmission line length in 1994 unavailable. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
Consolidated Water Power Company	No	FERC Form 1 unavailable from 1988 to 1993.
Consumers Energy Company	No	Reported negative O&M costs in 2002. In addition, transmission line length data is missing from 2001-2015.
Dayton Power and Light Company	Yes	Had noisy transmission length data for 1994. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
Delmarva Power & Light Company	Yes	Dataset complete.
Dominion Energy South Carolina, Inc.	Yes	Dataset complete.
DTE Electric Company	No	Had extremely spikey MRS data 2006 onwards and reported zero transmission lines from 2010 onwards.
Duke Energy Carolinas, LLC	Yes	Dataset complete.
Duke Energy Florida, LLC	Yes	Dataset complete.
Duke Energy Indiana, LLC	No	Reduction in O&M expenses in 2001 caused a negative MRS, which resulted in a significant dip in MRS growth for 2002.
Duke Energy Kentucky, Inc.	No	Had negative O&M costs for 2018.
Duke Energy Ohio, Inc.	No	Reduction in O&M expenses in 2001 resulted in a negative MRS figure.
Duke Energy Progress, LLC	Yes	Dataset complete.
Duquesne Light Company	Yes	Transmission line length for 1998 not available. Imputed value based on the average transmission line length between 1997 and 1999.

El Paso Electric Company	Yes	Dataset complete.
Emera Maine	No	FERC Form 1 unavailable from 1988 to 1993.
Empire District Electric Company	Yes	Dataset complete.
Entergy Arkansas, LLC	Yes	Dataset complete.
Entergy Louisiana, LLC	No	FERC Form 1 unavailable before 2006.
Entergy Mississippi, LLC	Yes	Dataset complete.
Entergy New Orleans, LLC	Yes	Dataset complete.
Entergy Texas, Inc.	No	FERC Form 1 unavailable before 2008.
Evergy Kansas South, Inc.	Yes	Dataset complete.
Evergy Metro, Inc.	Yes	Transmission line length data not available for 1994. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
Evergy Missouri West, Inc.	No	FERC Form 1 unavailable from 1988 to 1993, as well as other data unavailable sporadically for other years.
Fitchburg Gas and Electric Light Company	No	FERC Form 1 unavailable from 1988 to 1993.
Florida Power & Light Company	Yes	Transmission line length data not available for 1994. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
Florida Public Utilities Company	No	FERC Form 1 only available from 2002 to 2017.
Georgia Power Company	Yes	Dataset complete.
Golden State Water Company	No	FERC Form 1 unavailable before 2003.
Green Mountain Power Corporation	Yes	Transmission line length data not available for 1998 and 1999. We imputed these values using the 1997 figure and the transmission lines added during 1998 and 1999.
Gulf Power Company	Yes	Dataset complete.
Hawaii Electric Light Company, Inc.	No	FERC Form 1 unavailable before 2005.
Hawaiian Electric Company, Inc.	No	System peak data only available between 1994-2008. Other key metrics are missing sporadically as well.
Idaho Power Company	Yes	Dataset complete.
Indiana Michigan Power Company	No	Reports negative O&M costs from 1994 to 2009.
Indianapolis Power & Light Company	Yes	Dataset complete.
Jersey Central Power & Light Company	No	Reports zero in labor costs but has non-zero O&M costs from 1999 to 2002.

Kentucky Power Company	No	Reported negative O&M costs in 1998, 1999, 2002, 2003, 2004, 2009.
Kentucky Utilities Company	Yes	Dataset complete.
Kingsport Power Company	No	FERC Form 1 unavailable from 1988 to 1993.
Liberty Utilities (Granite State Electric) Corp.	No	FERC Form 1 unavailable from 1988 to 1993.
Lockhart Power Company	No	FERC Form 1 unavailable from 1988 to 1993.
Louisville Gas and Electric Company	Yes	Dataset complete.
Massachusetts Electric Company	No	System peak data unavailable from 1999 to 2008.
Maui Electric Company, Limited	No	FERC Form 1 unavailable from 1988 to 1993, as well as other data unavailable sporadically for other years.
MDU Resources Group Inc.	Yes	Dataset complete.
Metropolitan Edison Company	No	Reports negative O&M costs in 2018.
MidAmerican Energy Company	No	FERC Form 1 unavailable before 1995.
Mississippi Power Company	Yes	Dataset complete.
Monongahela Power Company	Yes	Dataset complete.
Mt. Carmel Public Utility Company	No	FERC Form 1 unavailable from 1988 to 1993.
Narragansett Electric Company	No	System peak data missing from 1999 to 2009.
Nevada Power Company	Yes	Dataset complete.
New York State Electric & Gas Corporation	Yes	Transmission line length data not available for 1998. We imputed the 1998 value based on the average between 1997 and 1999.
Niagara Mohawk Power Corporation	Yes	System peak data not available for 2003. We imputed the 2003 value based on the average between 2002 and 2004. Transmission line length data not available for 1996. We imputed the 1996 value based on the average between 1995 and 1997. O&M wages in 2018 were substantially lower than in other years. Used the average of 2017 and 2019 to smoothen out.
North Central Power Co., Inc.	No	FERC Form 1 unavailable before 2006, and other key metrics for years after 2006 are missing.
Northern Indiana Public Service Company	Yes	Used the average of 1998 and 2000 for transmission operation wages to smoothen out the significant increase in 1999.
Northern States Power Company - MN	Yes	Dataset complete.

Northern States Power Company - WI	Yes	Dataset complete.
NorthWestern Corporation	No	System peak data only available from 1994 to 2005.
Northwestern Wisconsin Electric Company	No	FERC Form 1 unavailable from 1988 to 1993, as well as other data unavailable sporadically for other years.
NSTAR Electric Company	Yes	Dataset complete.
Ohio Edison Company	No	Transmission line data unreliable.
Ohio Power Company	No	Has extremely noisy MRS data throughout the study period.
Oklahoma Gas and Electric Company	Yes	Dataset complete.
Orange and Rockland Utilities, Inc.	Yes	Dataset complete.
Otter Tail Corporation	Yes	Dataset complete.
Otter Tail Power Company	No	FERC Form 1 unavailable before 2009.
Pacific Gas and Electric Company	Yes	Transmission line length data not available for 1994. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
PacifiCorp	Yes	Dataset complete.
PECO Energy Co.	Yes	Transmission line length data not available for 1994. We imputed the 1994 value using the 1995 figure and the transmission lines added during 1995.
Pennsylvania Electric Company	No	Reports zero in labor costs but has non-zero O&M costs from 1999 to 2002.
Pennsylvania Power Company	No	Transmission line data unreliable.
Portland General Electric Company	Yes	Dataset complete.
Potomac Edison Company	Yes	Dataset complete.
Potomac Electric Power Company	Yes	Dataset complete.
PPL Electric Utilities Corporation	Yes	Dataset complete.
Public Service Company of Colorado	Yes	Dataset complete.
Public Service Company of New Hampshire	Yes	Dataset complete.
Public Service Company of New Mexico	Yes	Dataset complete.
Public Service Company of Oklahoma	Yes	Dataset complete.
Public Service Electric and Gas Company	Yes	Transmission line length data not available for 2004. We imputed the 2004 value based on the average between 2003 and 2005.
Puget Sound Energy, Inc.	Yes	Dataset complete.

Rochester Gas and Electric Corporation	Yes	Dataset complete.
Rockland Electric Company	No	FERC Form 1 unavailable from 1988 to 1993.
San Diego Gas & Electric Company	Yes	Dataset complete.
Sierra Pacific Power Company	Yes	Dataset complete.
Southern California Edison Company	Yes	O&M expenses spiked in 1998 and we are unable to explain this spike. We retained this company, however, since there is no clear reason to make adjustments to the O&M.
Southern Indiana Gas and Electric Company	No	Labor expense is greater than O&M expense in 2002, which results in negative MRS.
Southwestern Electric Power Company	Yes	Dataset complete.
Southwestern Public Service Company	Yes	Dataset complete.
Superior Water, Light and Power Company	No	FERC Form 1 unavailable from 1988 to 1993.
Tampa Electric Company	Yes	Dataset complete.
Texas-New Mexico Power Company	No	System peak not reported for any years.
Toledo Edison Company	No	Transmission line data unreliable.
Tucson Electric Power Company	Yes	Dataset complete.
UGI Utilities, Inc.	No	FERC Form 1 unavailable before 2004, and other key metrics missing after 2004.
Union Electric Company	Yes	Dataset complete.
United Illuminating Company	Yes	Dataset complete.
Unitil Energy Systems, Inc.	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
UNS Electric, Inc.	No	FERC Form 1 unavailable before 2003.
Upper Peninsula Power Company	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
Virginia Electric and Power Company	No	Reported negative O&M costs in 2018.
West Penn Power Company	Yes	Dataset complete.
Westar Energy (KPL)	No	FERC Form 1 unavailable from 1988 to 1993.
Western Massachusetts Electric Company	No	FERC Form 1 unavailable after 2017.
Wheeling Power Company	No	Transmission plant data unavailable in 1993.
Wisconsin Electric Power Company	No	Transmission line data unavailable after 2000. Has zero labor costs between 2003-2007.

Wisconsin Power and Light Company	No	Transmission line data unavailable after 2000. Has negative O&M costs for two years.
Wisconsin Public Service Corporation	No	Transmission line data unavailable after 2000.
Alcoa Power Generating Inc.	No	FERC Form 1 unavailable from 1988 to 1993 and in 2017.
Indiana-Kentucky Electric Corporation	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
Maine Electric Power Company, Inc.	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
National Grid Generation, LLC	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
New England Electric Transmission Corporation	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
New England Hydro-Trans. Elec. Co., Inc.	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
New England Hydro-Transmission Corporation	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.
New England Power Company	No	System peak data unavailable for most years.
Ohio Valley Electric Corporation	Yes	Used the industry-wide average ROE since RRA does not have a history of ROE for this company.
Southern Electric Generating Company	No	System peak data unavailable for most years.
System Energy Resources, Inc.	No	System peak data unavailable for all years.
Nantucket Electric Co.	No	FERC Form 1 data unavailable for most years.
Sharyland Utilities, LLC	No	FERC Form 1 data unavailable for most years.
Versant Power	No	FERC Form 1 data unavailable for most years.
Vermont Electric Transmission Company, Inc.	No	FERC Form 1 unavailable from 1988 to 1993, as well as data missing for other years.

Appendix II – Bios

Dr. Agustin J. Ros is a Principal of the Brattle Group and has 25 years of consulting and agency experience in regulatory and public utilities economics in network industries, particularly energy and telecommunications. He specializes in TFP and performance-based ratemaking, cost of service, demand studies, competition analysis and disputes, damages, and econometric modelling. He has provided dozens of expert reports before Public Utility Commissions and Federal agencies in the United States, Canada and more than a dozen countries and before the International Chamber of Commerce Arbitration Panel. Dr. Ros is an Adjunct Professor at the International Business School at Brandeis University where he teaches a course on regulatory and antitrust economics. He previously taught a similar course at Northeastern University. Dr. Ros has worked on dozens of TFP studies involving electricity, gas and telecommunications. He worked on the early TFP studies before the Federal Communications Commission and before state PUCs involving the incumbent local telephone companies. His work continued internationally, working on TFP studies in Canada. Dr. Ros worked on behalf of the Alberta Public Utilities Commission to conduct a TFP study for the electricity and natural gas distributors in Alberta and he has led TFP projects throughout Latin America.

Dr. Ros has extensive experience estimating econometric models in consulting projects as well as in his research in peer-reviewed academic and industry journals. His econometric research has been published in the *Energy Journal, Journal of Regulatory Economics*, *Review of Industrial Organization*, *Review of Network Economics*, *Telecommunications Policy*, and *Info*. He has a B.A. in economics from Rutgers University and has an M.S. and Ph.D. in economics from the University of Illinois at Urbana-Champaign.

Dr. Walter Graf is an Associate at The Brattle Group with expertise in electricity market analysis and wholesale market design. Dr. Graf is also an economist and expert statistician and econometrician. His work focuses on addressing economic questions facing regulators, market operators, and market participants in the electricity industry, especially related to the ongoing industry decarbonization and clean energy market evolution. Dr. Graf has worked on several projects related to transforming the electricity markets to quantify the system value of additional carbon-free resources, improving efficiency of renewable resource integration, and designing mechanisms to incentivize clean energy development using market-oriented approaches. Dr. Graf has also been involved in multiple projects designing capacity market mechanisms and assisting market participants prepare for participation in capacity markets and to project potential capacity revenues; analysis of wholesale electricity rate options for a generation and transmission cooperative; long-term load forecasting and resource adequacy planning for electric utilities; a study of market power mitigation options for an electricity market operator; analysis of the effect of distributed generation on customer loads and electric bills; and advising a transmission owner on matters related to a renewable energy procurement.

Dr. Graf holds a Ph.D. and M.S. in Agricultural and Resource Economics from the University of California, Berkeley, and a B.S. in Economics and B.S.E. in Civil and Environmental Engineering from the University of Michigan.

Sai Shetty is an Electricity Modeling Specialist at The Brattle Group with experience in the regulation and economics of the energy sector. With a background in econometrics, his work focuses on the application of econometric principles to understand outcomes in electricity markets. Mr. Shetty has worked with electric utilities on innovative pricing strategies to estimate customer load impacts attributed to pricing pilots and in performance based regulation to help quantify productivity growth in the electric transmission industry. Mr. Shetty has also been involved in projects estimating demand for electric vehicles and residential solar photovoltaics in the US; analysis of the Value of Lost Load (VoLL) to study the cost of electricity outages using statistical approaches based on historic data; and estimating cross-subsidies as a result of Net Energy Metering based on alternative electric rate designs.

Mr. Shetty holds an M.S. in Economics from the University of Wisconsin – Madison and a B.Tech degree in Chemical Engineering from the National Institute of Technology Karnataka, India.

Maria Castaner is a Senior Research Analyst at The Brattle Group with experience in the deep decarbonization of transportation, heating and power sectors; retail rate design and emerging distributed energy technologies. Ms. Castaner has worked on several analyses evaluating the impact of economy-wide decarbonization on existing assets, long-term planning needs, and business models for electric utilities. Ms. Castaner has also been involved in multiple projects designing innovative pricing strategies for electric utilities, analyzing the effect of distributed generation on electric bills, and evaluating the cost-effectiveness of demand response programs.

Ms. Castaner holds a B.S. in Chemical Engineering and Economics from the University of Pennsylvania.