Rapport d'expertise de Concentric Energy Advisors sur les caractéristiques du MRI du Transporteur

– Phase 3 –

PERFORMANCE BASED REGULATION:
PHASE III PLAN PARAMETERS FOR HQT

PREPARED FOR:
HYDRO-QUÉBEC TRANSÉNERGIE

R-4058-2018

BEFORE THE: RÉGIE DE L'ÉNERGIE

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Section 1:
Introduction

The Régie determined in D-2018-001 (or Phase I Decision)[1] the principal characteristics of a first-generation performance-based regulation plan (PBR or MRI)[2] for Hydro Quebec Transmission (HQT or the Carrier). In this January Decision, the Régie outlined a general framework for a revenue cap incentive regulation plan. The first MRI is to be based on a cost-of-service methodology for year 1 (2019), and an indexed-based formula for operating expenses (Opex) for years 2, 3 and 4 (2020-2022). Capital expenditures (Capex) will be treated on a cost of service basis.

In reaching this decision, the Régie determined certain parameters in its Phase I Decision, found that a Phase II would not be necessary, and left other parameters to be determined in Phase III, the subject of this immediate proceeding.

Concentric Energy Advisors (Concentric) has been asked by HQT to provide an assessment and recommendation for certain plan parameters that are to be decided in this Phase III. This report contains Concentric's analysis and recommendations for these parameters and builds on the previous research Concentric has provided before the Régie on these matters.[3]

Concentric presents its findings and conclusion on the recommended X factor for HQT in Section 2. Section 3 discusses Concentric's recommendation for HQT's Off-Ramp. Finally, Section 4 addresses the Régie's directive to propose a parametric formula for Capex. In this section, Concentric presents the approaches to formulaic capital it has identified in other jurisdictions, as well as its recommendation for the purposes outlined in the Régie's directive in D-2018-001.

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1 Régie de l'énergie, D-2018-001, R-3897-2014, January 5, 2018, Phase: 1 Decision.

2 The terms MRI and PBR are used synonymously to describe multi-year performance based rate plans.

3 Performance Based Regulation: Recommendations, Prepared for: Hydro-Québec Distribution & Hydro-Québec Transmission, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, Revised February 10, 2016.
Performance Based Regulation: Productivity Factor for HQD, Prepared for: Hydro-Québec Distribution, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, June 30, 2017. This report was attached to HQD's submission filed with the Régie on June 29th, however, the date on the Concentric report was left at June 30th. This report is referenced as Concentric June 30, 2017 Report.
Performance Based Regulation: Recommended X Factor, Prepared for: Hydro-Québec Distribution, R-4011-2017, before the: Régie de l'énergie, Concentric Energy Advisors, January 5, 2018 (HQD-20, document 2).
Performance Based Regulation: Productivity Factor Research for HQT, Prepared for: Hydro-Québec TransÉnergie, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, April 4, 2018 (C-HQT-HQD-0151).

Section 2:
X Factor

A. Introduction

The Régie determined in its January 5, 2018 Phase I Decision for the Carrier that an indexation formula (I-X) would be used to determine certain portions of HQT's revenues while other elements would be determined based on cost of service. In its Phase I Decision for the Carrier, the Régie determined that the X factor should be set based on its informed judgement. The Régie commented:

> *The Régie is of the opinion that the reasons for its decision D-2017-043 justifying the choice of the judgment-based method for determining the value of the X factor to be included in the Distributor's indexing formula are also valid for the MRI of the Carrier, particularly with regard to the time needed to implement it.*[4]

And:

> *To this end, the Carrier must provide to all stakeholders the updates or additional studies to those provided by the Distributor that are likely to inform the Régie as to the determination of the X factor for the Carrier in Phase III by March 31, 2018.*[5]

B. Approach

In response to the Régie's requirements, Concentric researched studies that would inform the determination of an appropriate X factor for this first-generation MRI. This report entitled "Performance Based Regulation: Productivity Factor Research for HQT" (or Research Report) was filed with the Régie on April 4, 2018.[6] As recognized in the Research Report, there are multiple methodologies to help inform X for distribution utilities, ranging from observing past productivity gains to industry benchmarking studies to complex productivity studies. The challenge in this case is to identify and determine the appropriate analyses and methodologies to be used for informing X for transmission utilities.

Concentric highlighted several reasons for the lack of comparable productivity data on transmission companies in relation to distribution utilities. Among these factors are:

- Traditional approaches to performance-based regulation adopted for distributors have been more selectively adopted for the regulation of transmission companies;
- Transmission, as a share of the customer's final bill, is typically the smallest cost component, in contrast to generation and distribution;
- The capital intensive and project specific nature of transmission creates a less homogeneous operating and cost profile; and
- Challenges in terms of creating appropriate peer groups for cost benchmarking and industry productivity analysis.

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4 D-2018-001, R-3897-2014 Phase I, paragraph 106 (translation).
5 D-2018-001, R-3897-2014 Phase I, paragraph 110 (translation).
6 Performance Based Regulation: Productivity Factor Research for HQT, Prepared for: Hydro-Québec TransÉnergie, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, April 4, 2018 (C-HQT-HQD-0151).

In response to the Régie's request, Concentric researched international examples of performance based regulatory frameworks for transmission companies. Concentric's research targeted programs identified by Elenchus[7] in its report conducted for the Régie, studies identified by PEG in Phase I of this proceeding, and an independent review of the literature and regulatory agencies to identify other pertinent examples. Concentric focused on models of performance-based ratemaking for electric transmission, and the use of productivity or benchmarking studies supporting the development of these programs. Our research indicates that PBR applied to transmission is not uniform. Regulators place an emphasis on cost control but also use reliability and performance to create incentives for transmission companies. For the reasons cited above, and because transmission service providers are less commonly regulated under performance-based regulation, transmission-specific productivity research is far more limited.

This point is underscored by the consultant to the Australian Energy Regulator (AER) on these matters:

> *While economic benchmarking of distribution network service providers (DNSPs) is relatively mature and has a long history, there have been very few economic benchmarking studies undertaken of TNSPs [transmission network service providers]. Economic benchmarking of transmission activities is in its relative infancy compared to distribution.*[8]

The AER expands on this topic in its 2017 transmission network service provider benchmarking report where it states:

> *Transmission networks have undertaken cost benchmarking for a number of years, but whole of business [sic] benchmarking of electricity transmission networks is relatively new. Compared to electricity distribution networks there have not been many whole of business [sic] benchmarking studies of transmission networks. MTFP [multilateral total factor productivity] analysis is in its early stage of development in application to transmission networks. Further, there are only a few electricity transmission networks within Australia which makes efficiency comparisons at the aggregate expenditure level difficult.*[9]

In addition to the international research, Concentric worked with HQT to examine its past record of productivity, as measured by the cost categories covered by the formula adopted by the Régie in its Phase I Decision for HQT. This analysis produced a "Kahn method" X factor. This method refers to the work of economist and regulatory expert Alfred E. Kahn.[10] Dr. Kahn developed a methodology for determining the cost trends of regulated industries and presented his results before various regulatory commissions. His approach, as reflected in his work before the U.S. Federal Energy Regulatory Commission (FERC), was used for purposes of determining an appropriate price cap index for oil pipelines. Dr. Kahn constructed a sample of pipelines from all those reporting to the

[7] Performance Based Regulation - A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions, Elenchus Research Associates, R-3897-2014, January 2015.

[8] Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, Report prepared by Denis Lawrence, Tim Coelli and John Kain for the Australian Energy Regulator, Eden, 17 November 2014, p. 2.

[9] AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 20.

[10] Dr. Kahn served as chairman of the New York Public Service Commission, chairman of the Civil Aeronautics Board, where he oversaw the deregulation of the airline industry, advisor to the President on Inflation under Jimmy Carter, and chairman of the Council on Wage and Price Stability. He authored the well known text: The Economics of Regulation: Principles and Institutions, Wiley and Sons, 1970 (Volume I), and 1971 (Volume II). https://en.wikipedia.org/wiki/Alfred_E._Kahn

FERC and dropped from his sample those reported pipeline costs in any given year which were in the upper and the lower 25% of the cost spectrum, primarily to correct for statistical outliers and for incomplete or questionable data. In other words, he used the middle 50% of reported pipeline costs for computing industry-wide weighted average costs for purposes of calculating the industry cost trend.[11]

Taken more broadly, the Kahn method can be considered as a measure of productivity as revealed by the industry's past experience and actual accounting costs. As illustrated in the next section, the Australian Energy Regulator calculates productivity in this manner as an input to appropriate X factors for its regulated transmission companies. The Vermont Public Service Board relied on this approach exclusively in setting its first-generation X factor for Vermont Gas. The Board found:

> *The operating-cost cap is based on the Company's growth in operating costs per customer between 1999 and 2004, which was 0.39 percent less than the consumer inflation rate, representing "productivity gains" that the Plan shares between customers and the Company.*[12]

That initial Vermont Gas plan was replaced by a "Successor Plan", covering an additional five years (2012-2016), and the X factor remained set at 0.39%.[13]

In this proceeding, PEG also utilized such an approach with historic cost data for HQD in developing its recommendation for HQD's X factor.[14]

Taken together, this regulatory research and HQT's track record of productivity provide a reasonable basis for a recommended X factor for this first-generation MRI for the Carrier.

C. Regulatory Research

Concentric's research identified six international programs where transmission productivity had been assessed, and/or rates for transmission companies were established according to formulaic or performance-based rate mechanisms. These programs included:

- Europe - Transmission Operators E3 Grid Benchmarking Study
- U.K. - Ofgem RIIO Framework
- Australia – Regulation of Electricity Transmission Network Service Providers
- New Zealand - Regulation of Transpower
- Norway – Regulation of Statnett
- U.S. – FERC Formula Rates

[11] See: Docket No. RM93-11-001, Order No. 561-A, Revisions to Oil Pipeline Regulations Pursuant to Energy Policy Act of 1992, July 28, 1994.

[12] Docket No. 7109, Petition of Vermont Gas Systems, Inc. for approval of an alternative-regulation plan, Order dated September 21, 2006, p. 5.

[13] Docket No. 7803, Petition of Vermont Gas Systems, Inc., for approval of a Successor Alternative Regulation Plan, Order dated August 21, 2012, p. 6.

[14] Lowry and Makos, MRI Design for Hydro-Québec Distribution, January 5, 2018, Errata January 11, p. 25.

While this research provides useful perspective on the regulation of transmission companies, we ultimately find that the broad array of productivity studies (and specifically total factor productivity (TFP) studies) utilized in distribution programs to set revenue path trajectories are lacking for transmission companies. And where performance-based programs are implemented, in the place of TFP studies, benchmarking and peer cost analysis are more prevalent and utilized to set custom revenue paths. The following summaries capture the most relevant aspects of this research for purposes of establishing HQT's X factor, and supplements Concentric's Research Report.

Europe

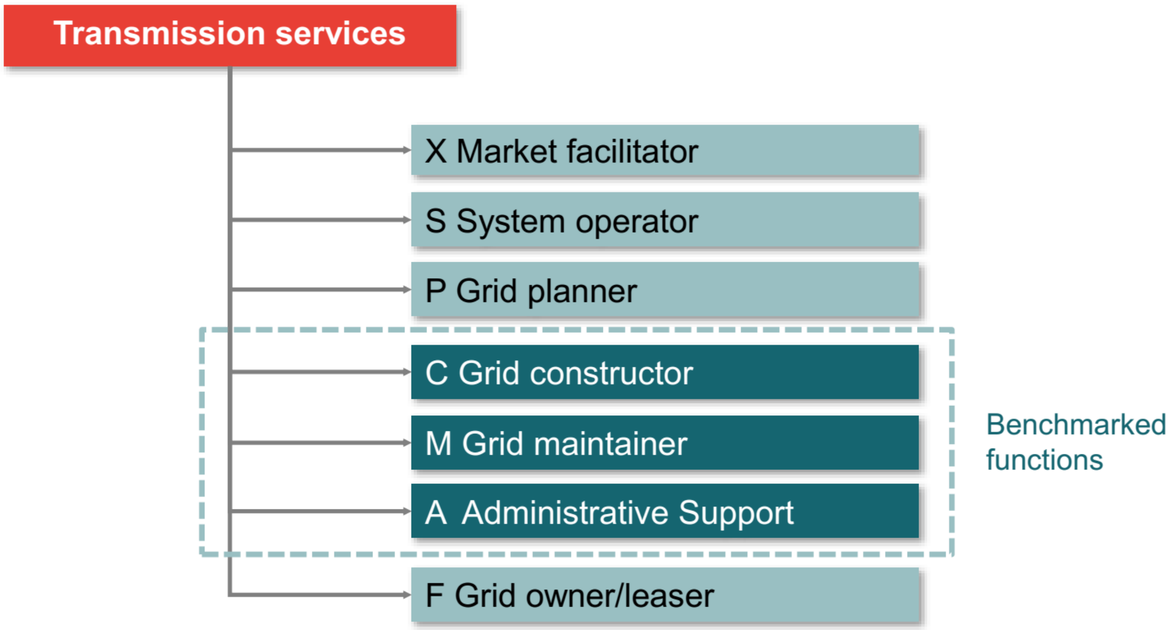
European electricity transmission system operators are regulated by national and European directives. Revenue allowances for these companies are set by national regulatory authorities (NRAs). One task typically undertaken by these NRAs is to assess whether the regulated revenues are based on efficient costs. Such analysis is often based on cost benchmarking among network companies. Given the limited number of national transmission system operators (TSOs), which limits the ability of NRAs to undertake benchmarking that is national in scope, a number of European NRAs have decided to collaborate in order to develop an international sample of comparator companies.[15]

The E3Grid study of 21 transmission system operators in continental Europe and the U.K serves as a basis for establishing baselines for efficient operations. Each company is ranked on its cost efficiency against the "efficient frontier." It is left to regulators in each country to determine how, or if, the study is applied to rates. The benchmarking is based on total expenditures (Totex), which is the sum of operating expenditures (Opex) and capital expenditures (Capex), measured as capital consumption (depreciation and return). Because the TSOs do not all provide the same services, the benchmarked cost categories were limited to the three common operational functions, as illustrated below. [16]

[15] E3GRID 2012 European TSO Benchmarking Study, A Report for European Regulators, Frontier Economics, Technical Report, August 2013, p. 1.

[16] E3GRID 2012 European TSO Benchmarking Study, A Report for European Regulators, Frontier Economics, Technical Report, August 2013, p. 39.

Figure 1: E3Grid Study Benchmarked Functions of Transmission Operators



The study authors found that the net change in productivity for the industry averaged -1.4% for the 2007-2011 study period, reflecting the most recent five years of data available at the time of the study. The study decomposed this result into two components: the "efficiency change" and the "technical change." According to the authors, the Malmquist productivity index[17] captures the net change of productivity, the efficiency change captures "catch-up effects" and technical change captures "frontier shifts." This means that, on average, the 21 transmission operators improved their efficiency by an average of 2.4% per year over the period, as measured against the most efficient benchmark. But, the most efficient benchmark was shifting downward by an average of -1.0% over the same period. The combined effect of the two resulted in a -1.4% net decrease in productivity over the period. While these results were based on the total of both capital and operating expenditures, the authors attempted to isolate Opex from the total and reported similar results. The study did not specifically report an Opex productivity trend (only the benchmarking relationship between the most efficient "frontier" and the average efficiency of the companies, and the number of individual companies that reach the frontier). The average efficiency was measured at 86% compared to 86% in the base model. [18]

[17] The concept of Malmquist productivity index was first introduced by Malmquist (1953) and used by several authors and in productivity studies. It is an index representing Total Factor Productivity (TFP) growth of a firm or economy that reflects progress or regress in efficiency along with progress or regress of the frontier technology over time under the multiple inputs and multiple outputs framework. See: Handbook on Data Envelopment Analysis (2004), Editors: William W. Cooper Lawrence M. Seiford Joe Zhu, Chapter 8: Malmquist Productivity Index, Kaoru Tone, pp. 203-227.

[18] E3GRID 2012 European TSO Benchmarking Study, A Report for European Regulators, Frontier Economics, Technical Report, August 2013, p. 13, and pp. 103-105.

Table 1: E3Grid Study Productivity of Transmission Operators

2007-2011	Malmquist (% point changes)	Efficiency Change (% point changes)	Technical Change (% point changes)	Observations
All TSOs	-1.4%	2.4%	-1.0%	81
Continental Europe	0.0%	4.5%	-0.8%	50
Scandinavia	-1.4%	0.6%	-1.9%	15
UK	-7.0%	-2.8%	-1.1%	12

Note: the % point change is given by: (average of Malmquist indices for each company) – 1. The decomposition of the Malmquist index for each TSO *i* in each year *t* is calculated by: $MI_{i,t} = EC_{i,t} \times TC_{i,t}$. This implies that the net effect in the table above cannot be calculated simple by adding the EC and TC.

Continental Europe includes TSOs from all countries except UK, Scandinavia and Estland.

Scandinavia includes TSOs from Finland, Norway, Sweden and Denmark

Source: Frontier/Sumicsid/Consentec

Looking for evidence of application of the study results to regulatory action, see Norway (in Section 7 of Concentric's Research Report).[19] The Norwegian regulator uses these results over a five-year period to establish performance targets for Statnett, Norway's primary transmission operator, with an incentive-based revenue cap model. The European and Norway models illustrate what is possible with the participation of 21 transmission companies and a collaboration between regulators and the regulated transmission entities. This is not currently the case in North America, however, and the benchmarking data from the E3GRID study is not readily applicable to HQT's Opex-specific MRI program. The measurement of Opex efficiency against a European frontier does not establish an Opex cost trend which can be translated into an X factor for HQT. The benchmarking study measures relative efficiency, and could be used to set targets for the participating companies in the study group (e.g., a goal of reaching top quartile in Opex efficiency within the peer group), but no specific Opex trend is captured by the study that could be applied to HQT's X factor. The net productivity trend of -1.4% can, however, be taken as an indicative measure of European transmission productivity over this period—reflecting both the efficiency improvements of the industry and the offsetting declines of the most efficient benchmark.

19 The revenue cap is set annually, based on a formula of 40 percent cost recovery and 60 percent cost normalization resulting from benchmarking models. See: Performance Based Regulation: Productivity Factor Research for HQT, Prepared for: Hydro-Québec TransÉnergie, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, April 4, 2018 (C-HQT-HQD-0151), pp. 29-30.

U.K.

In the U.K., the RIIO (Revenue = Incentives + Innovation + Outputs) framework established for transmission operators places significant emphasis on outputs, or performance targets that are linked to revenue. Companies must deliver these outputs either annually or on an 8-year basis. The allowed revenue is set based on a forecast of total expenditures with incentives linked to outputs and the quality of the forecast. This framework applies to the U.K's three onshore transmission companies, with a similar framework for electric & gas distributors. There are inflationary elements within the RIIO approach, but it is fundamentally a building-block model based on a forecast of costs with an emphasis on performance against a broad array of outputs.

For example, the Office of Gas and Electricity Markets (Ofgem) established its most recent regulatory framework covering the eight-year period 2013-2021 for National Grid Electricity Transmission (NGET). NGET owns and maintains the electricity transmission network assets across England and Wales. After extensive consultations, Ofgem approved an eight-year total revenue path. The revenue path is constructed from several components. Ofgem incorporates a proposed productivity improvement of 0.8% per year applied to total expenditures (Totex). For NGET, this number is composed of a 0.5% Opex productivity target and 0.8% Capex productivity target, suggesting that Capex is dominating Opex in the Totex.[20] These targets are based on a combination of benchmarking analysis and forecast review by Ofgem. However, there are several adjustments to allowed revenues, providing increased revenue allowances for innovation spending, for volume-based cost drivers including load and non-load related Capex, a provision for "uncertainty mechanisms" and related adjustments. Total allowed revenues for NGET are illustrated below.[21] Allowed revenues actually grow at an average annual rate of 3.4% in real terms, and 6.3% in nominal terms, well in excess of the initial productivity target.

Table 2: NGET's Allowed Revenues (Best View)

NGET £m Best View	2012-13 per Rollover	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Allowed revenues (nominal)	1,506	1,600	1,801	1,959	2,114	2,190	2,385	2,403	2,452
Allowed revenues (2009-10 prices)	1,332	1,376	1,507	1,595	1,674	1,687	1,787	1,752	1,738
Yr on Yr Change (2009-10)		3.3%	9.5%	5.8%	5.0%	0.8%	5.9%	(2.0%)	(0.8%)
Cumulative Change (2009-10)		3.3%	13.2%	19.7%	25.7%	26.7%	34.2%	31.5%	30.5%

The U.K framework is comprehensive but represents a different approach than that adopted by the Régie for this first-generation MRI for HQT. Ofgem relies on a forecast revenue requirement factoring in a productivity target with a number of other adjustments. These forecasts cannot be uniformly applied to HQT's Opex cost trend without consideration of the many adjustments, and therefore cannot be practically used to establish an appropriate X factor for HQT.

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20 Ofgem, RIIO-T1/GD1: Real price effects and ongoing efficiency appendix, December 17, 2012, p. 6, as applied to NGET's Transmission Operations.

21 Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Final decision – Overview document, December 17, 2012, p. 29. "Best view" is the expenditure that we consider the licensees will need to deliver the outputs under their central scenario. It comprises "baseline" and "uncertainty mechanism" funding, p.26.

New Zealand

In New Zealand, the country's transmission provider, Transpower, is subject to a building-block framework with various input methodologies under which Transpower forecasts it operating and capital expenditures. The maximum revenue that Transpower may recover for each pricing year in the regulatory period, net of the sum of pass-through costs and the sum of recoverable costs, is the forecast maximum allowable revenue. Transpower's 2015/16 annual revenue for the regulated parts of the grid amounted to $916.6 million and will increase to close to $977.4 million per annum in 2019/2020.[22] This is a five-year rate plan, with annual true-ups for certain items (e.g., assumptions regarding inflation built into the forecast) and adjustments for pass-through costs. The process begins with a proposed revenue path for both Opex and Capex from Transpower, and is subject to review by stakeholders, independent experts, and ultimate approval by the regulator. This is Transpower's second incentivized multi-year rate plan. The end result is an approved rate path based on the Opex and Capex allowances, plus provision for larger "listed projects" which are approved separately on a project-by-project basis over the rate period and treated separately.

Table 3: Transpower's Opex and Base Capex Allowances (Nominal)

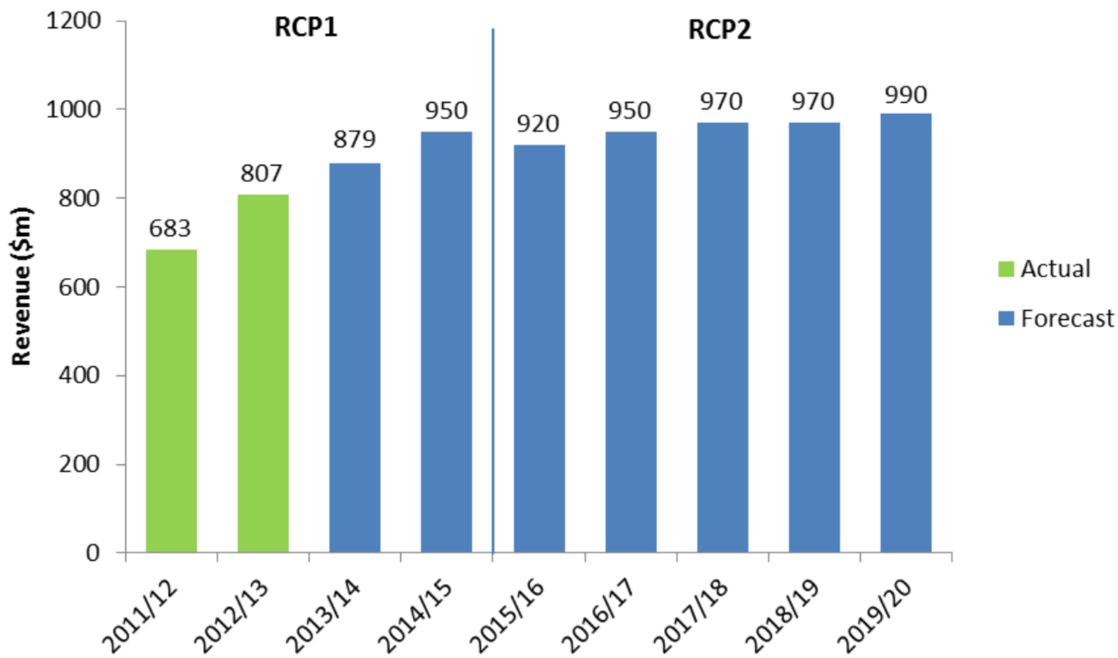
	2015/16	2016/17	2017/18	2018/19	2019/20	Total RCP2
Opex ($m)	276.6	284.6	292.5	294.0	296.4	**1,444.0**
Base capex ($m)	235.2	249.5	242.0	231.6	213.1	**1,171.5**

Note: The base capex allowances above are commissioned amounts and include Transpower's proposed 7.5% 'productivity' adjustment. Figures may not add exactly due to rounding.

The resulting revenue path is illustrated below.[23]

[22] New Zealand Electricity Authority, Transmission pricing methodology: issues and proposal, Second issues paper, May 2016, p. ii.
[23] Commerce Commission of New Zealand, Setting Transpower's individual price-quality path for 2015—2020, August 29, 2014, pp. 12 and 22.

Figure 2: Transpower's Revenue over RCP1 and RCP2



Of note, the Transpower regulatory framework is a custom rate plan based on a company-specific forecast of costs. While the approach may be informative to the Régie, these parameters cannot be directly applied to the determination of an appropriate X factor for HQT's Opex. As noted by Concentric in the revised proposal for HQT in Phase I: "This revised MRI approach takes into account comments expressed by stakeholders regarding the reliance on the "Building Block" approach with a three-year up-front forecast and their general preference for a mechanism that incorporates elements of an I-X approach. Stakeholders expressed concern over forecast variances for the 3-year term."[24] We would therefore not expect a forecast approach to Opex as a basis for setting the X factor in Phase III.

Australia

The one example we have identified of a partial productivity factor (PFP) measured for transmission companies is in Australia. In Australia, there are seven primary electric transmission entities, or transmission network service providers (TNSPs) regulated by the AER.[25] There are additional transmission networks in each state and territory, with cross-border interconnectors that link some networks. The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission network from Queensland to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The transmission networks in Western Australia and the Northern Territory do not interconnect with the NEM or each other. The AER regulates transmission revenues through a periodic revenue determination review which typically

[24] Regulation Recommendations: Revised, Prepared For: Hydro-Québec Transénergie, R-3897-2014, Before The: Régie de l'énergie, Concentric Energy Advisors, September 30, 2016, p. 1.

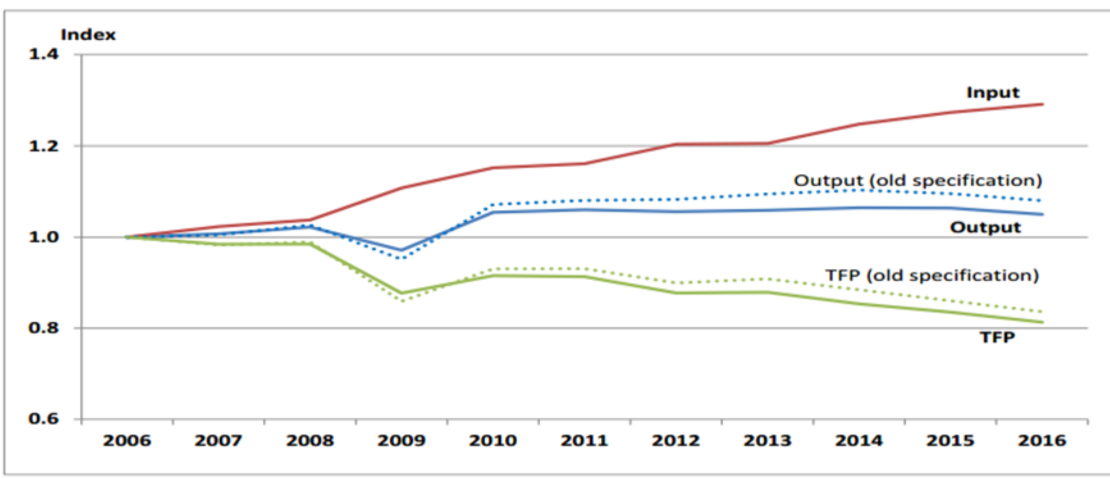
[25] These companies are: Ausnet, Directlink, ElectraNet, Murraylink, PowerLink, TasNetworks, TransGrid.

occurs every five years. Each TNSP submits a network expenditure proposal to the AER for a coming regulatory control period (e.g., 5 years) including forecast costs for each of the building blocks of their network expenditures separately for both Capex and Opex. The proposals include data and information to support estimates of needed expenditure. Where a proposed expenditure for a building block meets the criteria and tests specified by the AER, it accepts the proposal. Where the AER is not satisfied that the relevant regulatory criteria and tests are met, the AER can reject the proposal and estimate an amount it believes reasonably reflects the regulatory requirements. Benchmarking can also inform these AER estimates.

While the revenue determination takes the general form of CPI-X, the X itself is set as more of a "smoothing factor" aligned with the approved revenue path, with significant differences between companies and by year. The X factors for total revenue set for the most recent 2016-2021 rate years range from -2.7% (ElectraNet) to 3.2% (AusNet). The X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue. The calculation of the actual annual maximum allowed revenue is adjusted for actual inflation, actual debt costs, and any approved pass through amounts.

The table below shows the results of AER's measurement of total factor productivity (TFP) for the five interconnected transmission companies serving the NEM.

Figure 3: AER's Transmission Benchmarking Results, 2006-2016



(Note: the new specification is now used.)

The AER measures an average long-term industry TFP of -2.1 per cent over 2006-16. As explained in the benchmarking report prepared by the AER's consultant:

> *Figure 1* [Figure 3 in this report] *shows the change in total industry inputs, outputs and total factor productivity (TFP) over the last 11 years.*
>
> *……*

> *As can be seen in figure 1, industry-wide TFP continued to decline over 2016 decreasing by 2.7 per cent. This is the third consecutive year of declining TNSP productivity – TFP decreased by 2.9 percent over 2014 and 2.2 per cent over 2015. It is also a faster rate of decline than the long term industry rate of a -2.1 per cent average annual decrease over 2006-16.*
>
> *……*
>
> *The long term decrease in TFP – by 19 per cent over the last 11 years – has been driven by network inputs growing at a faster rate than outputs. Total inputs increased 29 per cent over 2006-16 while total outputs grew by only five per cent.*[26]

This is a similar trend observed for U.S. electric distribution companies as cost inputs are exceeding outputs.[27]

The AER also examines both total and partial factor productivity indicators (PFP) for each of the five TNSPs, and for the transmission industry in aggregate. These data, as prepared by a consultant for the AER, are presented below. This analysis shows that the total factor productivity averaged -2.07% over the entire 2006-2016 period and -1.90% over the most recent 2012-2016 period. The Opex PFP averaged -0.64% over the full 2006-2016 period, and shifted to -1.80% over the more recent 2012-2016 period.

Table 4: Industry–level Transmission Output, Input, Total Factor Productivity and Partial Productivity Indexes, 2006–2016[28]

Year	*Output Index*	*Input Index*	*TFP Index*	*PFP Index*	
				Opex	*Capital*
2006	1.000	1.000	1.000	1.000	1.000
2007	1.007	1.023	0.984	1.005	0.976
2008	1.022	1.038	0.985	1.025	0.968
2009	0.971	1.107	0.877	0.951	0.848
2010	1.054	1.152	0.915	0.985	0.887
2011	1.060	1.161	0.913	1.041	0.868
2012	1.056	1.204	0.877	1.008	0.832
2013	1.059	1.205	0.879	1.051	0.823
2014	1.064	1.247	0.853	0.976	0.812
2015	1.063	1.273	0.835	0.966	0.792
2016	1.050	1.291	0.813	0.938	0.772
Growth Rate 2006–16	0.49%	2.56%	–2.07%	–0.64%	–2.59%
Growth Rate 2006–12	0.91%	3.09%	–2.19%	0.13%	–3.07%
Growth Rate 2012–16	–0.14%	1.76%	–1.90%	–1.80%	–1.87%

26 AER, Annual Benchmarking Report, Electricity transmission network service providers. November 2017, p. 7.

27 See, for example, the trends discussed in Performance Based Regulation: Recommended X Factor, Prepared for: Hydro-Québec Distribution, R-4011-2017, before the: Régie de l'énergie, Concentric Energy Advisors, January 5, 2018 (HQD-20, document 2).

28 Economic Insights Pty Ltd, Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report, Report prepared for Australian Energy Regulator, 6 November 2017, p. 8.

In explaining the results, the authors noted:

> *Over the 11–year period 2006 to 2016, industry level TFP declined with an average annual rate of change of –2.1 per cent. Although total output increased by an average annual rate of 0.5 per cent, total input use increased faster, at a rate of 2.6 per cent. Since the average rate of change in TFP is the average rate of change in total output less the average rate of change in total inputs, this produced a negative average rate of productivity change.*[29]

In evaluating the results of the study, the authors also considered the impacts of "redundancy payments" on both TFP and Opex PFP. Reform of electricity networks over the last several years has been accompanied by increased levels of redundancy payments as NSPs have restructured their operations to improve efficiency and reduce previous excess staffing levels. Redundancy payments are currently included in the Opex data used in the AER's economic benchmarking. If those redundancy payments are excluded, as shown in the following table, the productivity results improve by 0.25% (the difference between the -0.64% and -0.39%) over the entire 2006-2016 period.[30] Considering that HQT has not been subject to comparable redundancy payments, the productivity numbers excluding redundancy are a more appropriate comparator.

Table 5: Average Annual Transmission Industry TFP and Opex PFP Change Including and Excluding Redundancy Payments: 2006–2016, 2006–2012 and 2012–2016[31]

Year	*2006 to 2016*	*2006 to 2012*	*2012 to 2016*
TFP change including redundancy payments	–2.07%	–2.19%	–1.90%
TFP change excluding redundancy payments	–2.00%	–2.17%	–1.75%
Opex PFP change including redundancy payments	–0.64%	0.13%	–1.80%
Opex PFP change excluding redundancy payments	–0.39%	0.18%	–1.25%

While representing productivity trends for transmission companies in another country and operating environment, Concentric finds this industry data to be a useful benchmark because it is specific to five transmission operating companies and specific to Opex expenditures, resembling HQT's targeted expenditures under the I-X formula. In comparing Australia's network to Québec's, the NEM transmission network comprised of these five transmission networks are both privately and publicly owned: 3 are government owned and 2 are privately owned. Also,

> *The NEM transmission network is unique in the developed world in terms of its long distances, low density and long, thin structure. It reflects the often long distances between demand centres and fuel sources for generation. By contrast, transmission networks in the United States and*

[29] Economic Insights Pty Ltd, Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report, Report prepared for Australian Energy Regulator, 6 November 2017, p. 9.

[30] In Australia, notice of termination and redundancy pay forms part of the National Employment Standards (NES). The NES apply to all employees covered by the national workplace relations system, regardless of any award, agreement or contract. Employees receive redundancy pay based on their continuous period of service with their employer. This amount is paid at the employee's base pay rate for ordinary hours worked. The redundancy pay to an employee ranges from 4 weeks pay for employees with 1-2 year of service to 12 weeks for employees with 10 or more years of service. https://www.fairwork.gov.au/how-we-will-help/templates-and-guides/fact-sheets/minimum-workplace-entitlements/notice-of-termination-and-redundancy-pay

[31] Economic Insights Pty Ltd, Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report, Report prepared for Australian Energy Regulator, 6 November 2017, p. 18.

> *many European countries tend to be meshed and of a higher density. These differences result in transmission charges being a more significant contributor to end prices in Australia than they are in many other countries – for example, transmission* charges comprise about 10 per cent of *retail prices in the NEM3* [third phase of the National Electricity Market] *compared with 4 per cent in the United Kingdom.*[32]

While Australia's electric grid may be unique in contrast to other western countries, HQT is also unique. HQT's system serves long distances between generation and loads, and represents an even greater 25% of the average price of electricity.[33] The Australian data therefore serves as a useful international benchmark for HQT. Depending on the full period or more recent five years, the Opex X factor from the Australian sample is -0.39% to -1.25% (there would be no justification for taking the older partial period of 2006-2012).

D. HQT Productivity

In addition to the international research, Concentric examined HQT's past record of productivity, as measured by the specific cost categories covered by the formula. PEG measured HQT's aggregate revenue requirements using this approach in what it characterized as a "simple 'Kahn method' exercise."[34] The merits of such an approach are that it relies on revealed productive efficiency for the industry or company being measured. Unfortunately, we do not have comprehensive data on the Canadian or U.S. transmission industry to measure for these purposes, but HQT's own data provides a meaningful perspective on trends in operating expenditures in relation to inflation.

HQT has prepared this data for the past 10 years, breaking out the actual costs for expenditures included in the I-X component of the MRI formula. These costs include:

- Operating expenses
- Transmission purchases
- Power purchases
- Other internal billing revenue
- Corporate fees
- Interest related to government debt
- External revenues
- Other Retirement Costs

In preparing this analysis, Concentric made adjustments for items that it felt would have been treated as Y or Z factors under the MRI (i.e., pension costs, capitalized costs to investments, and specifically budgeted items) in order to create a baseline measurement of the I-X component of the formula on a retrospective basis. These expenditures were then compared with inflation, using the Régie's proposed two-factor inflation measure. Taken together this analysis results in an implied X factor for HQT's applicable operating costs over this 10-year period.

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32 https://electrical-engineering-portal.com/an-overview-of-australias-electricity-transmission-networks

33 Performance Based Regulation: Productivity Factor Research for HQT, Prepared for: Hydro-Québec TransÉnergie, R-3897-2014, before the: Régie de l'énergie, Concentric Energy Advisors, April 4, 2018 (C-HQT-HQD-0151), p. 4.

34 Lowry, "Incentive Regulation for the Transmission & Distributor Services of Hydro-Quebec", Revised HQT Draft 24 February 2017, p. 125.

Table 6: Kahn Factor Calculation for HQT

	Actuals									
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Operating expenses (2) (3)	738.9	760.2	767.1	803.3	758.9	818.0	839.7	853.4	845.0	940.0
Transmission purchases	18.3	19.0	18.7	17.9	17.4	17.7	18.9	19.2	19.4	19.0
Power purchases	7.0	14.0	14.3	13.3	12.9	14.2	14.6	14.9	14.9	15.2
Other internal revenues	(41.4)	(40.5)	(41.2)	(43.1)	(41.3)	(39.5)	(43.5)	(44.1)	(43.4)	(47.3)
Corporate fees	32.2	28.6	27.6	27.8	28.2	31.8	29.5	32.7	31.9	36.7
Interest related to government debt	(5.2)	(4.4)	(4.0)	(3.6)	(3.3)	(0.7)	(0.6)	(0.7)	(0.4)	(0.5)
External revenues	(4.9)	(3.3)	(3.4)	(3.4)	(5.4)	(10.0)	(9.6)	(10.3)	(8.3)	(8.7)
Other retirement costs										(111.5)
Total	**744.9**	**773.6**	**779.1**	**812.2**	**767.4**	**831.5**	**849.0**	**865.1**	**859.1**	**842.9**
Less:										
Factor Y - Pension costs	15.8	7.6	2.5	21.0	26.6	89.7	60.6	73.3	18.1	(52.1)
Factor Z - Specifically budgeted items	15.8	20.0	20.0	19.1	0.0	0.0	0.0	0.0	14.4	1.5
Applicable costs - Formula I - X	**713.3**	**746.0**	**756.6**	**772.1**	**740.8**	**741.8**	**788.4**	**791.8**	**826.6**	**893.5**
Inflation (%) (1)		2.33%	2.39%	1.63%	1.74%	2.71%	2.33%	1.31%	1.62%	1.45%
Authorized Growth ($M)		8.9	8.1	8.6	6.1	8.3	19.1	7.2	5.7	11.6
X - Implied (%)		-1.00%	2.05%	0.71%	6.59%	3.70%	-1.38%	1.79%	-2.05%	-5.25%
(1) HQT-4 Document 2									2013-2017 average	-0.64%
(2) Includes capitalized costs									2009-2017 average	0.57%
(3) Includes interest related to remediation for 2012, 2013, 2014										

The data reveal a productivity trend in HQT's Opex related costs of 0.57% measured over this ten-year period. When measured over the most recent five years, the trend decreases to -0.64%, consistent with the shift we see in Australia. Over both periods (2009-2017 and 2013-2017), HQT's Opex results illustrate a greater degree of productivity than those calculated for the Australian companies. Both trends illustrate a slowdown in Opex related productivity over the most recent five years as costs have exceeded inflation.

Table 7: Opex Trend Comparisons

Opex Trend	HQT	Australian TNSPs
Past Decade	0.57%	-0.39%
Most Recent Years	-0.64%	-1.25%

There are a number of factors involved in the estimation of productivity trends, involving both the data used, methods used to determine the trend, and the time-period analyzed. In the development of industry trends of productivity, it is important to consider multiple-year periods due to the considerable annual fluctuation in results from one year to the next. This is seen both in the HQT and Australian results. In the case of HQT, it is appropriate to consider 2012 as a base year for these purposes. The Régie previously made that determination when considering HQT's efficiency gains.

> [76] The Régie orders HQT to propose, as part of its next rate case, an efficiency tracking method that will identify and measure the efficiency gains sought annually. This method must demonstrate how HQT intends to achieve its efficiency related to CNE [Opex in HQT's nomenclature].

> [77] In addition, HQT recalibrated its CNEs, reflecting its new centralized organizational structure around the VPEI [Planning vice-presidency]. It is on this premise that HQT will henceforth be able to establish a new base of reference allowing a quantifiable follow-up on the efficiency efforts undertaken compared to the reference period.
>
> [78] In connection with the above order, the Régie directs HQT, as part of its next rate application, to implement the reference case representative of its new centralized organizational structure (VPEI). This base case will allow annual tracking of the efficiency gains related to CNE. The results will have to relate to the gains obtained since the year 2012.[35]

Recommended X Factor

Based on a combination of HQT's actual experience and the industry research with the costs covered by the Opex component of the MRI formula, Concentric recommends an X factor of -0.6%. This represents HQT's experience, as calibrated with the new MRI formula, over the past five years. It therefore represents the actual shift in Opex experienced by HQT in comparison with the previous period. This period of reference is consistent with the Régie's prior determination of 2012 as a benchmark year for performance, and consistent with the European timeframe for performance benchmarking. It brings HQT into general alignment with the 10-year performance of the Australian companies (excluding redundancy payments) but represents a significantly greater challenge in relation to the 2012-2016 Australian Opex productivity of -1.25%.

Another factor supporting the use of the HQT derived Kahn factor is the explicit use of the Régie's approved inflation factor in this calculation. The Régie commented on this importance in its Phase III Decision for HQD:

> *The Régie also points out that the value of the X factor cannot be determined independently of the value of the I factor and that the two factors form an inseparable whole, the total value of which ultimately serves to determine the growth of required revenues.*[36]

In its HQD Phase III Decision, the Régie expressed a preference for reliance both on expert studies and regulatory decisions when relying on evidence from other jurisdictions, and integration of the assumptions or context around these productivity studies.[37] In this case, there is not a record of X factors approved by other regulators specific to Opex that can be applied to HQT. However, Concentric has provided the context around these studies and the regulatory decisions (which typically apply to Totex) to inform both Concentric's recommendation and the Régie's understanding of the evidence.

Another concern expressed by the Régie in its HQD Phase III Decision is that only one regulator (Massachusetts) had approved a negative X factor.[38] The Régie should take assurance from the analysis and research provided by Concentric that a negative X factor (implying that costs are exceeding inflation) is supported for transmission companies. The European E3Grid study showed

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35 D-2014-035, paragraph 76 to 78 (translation).
36 D-2018-067, paragraph 112.
37 D-2018-067, paragraph 151.
38 D-2018-067, paragraph 15

negative productivity for the five-year study period; even though Ofgem begins with an 0.8% productivity target for Totex, National Grid's allowed revenues under its 8-year revenue cap grow 3.4% per year in real terms; New Zealand's Transpower's Opex revenues grow at 1.7% per year (prior to adjustments); Australia's Opex PFP's (adjusted for redundancy payments) average -1.25% for the past 5 years; and finally HQT's actual Opex cost trend has averaged -0.64% over the most recent five years. These trends do not mean these companies are not operating efficiently, only that operating cost pressures exceed inflation.

Also consistent with the Régie's HQD Phase III Decision,[39] Concentric does not find it necessary to add an additional stretch factor (s factor) to the X factor. Considering the introduction of HQT's parametric formula, the Carrier has been motivated by the Régie to achieve efficiencies so the measured X factor is a reasonable baseline for HQT's first generation MRI, and is supported by the evidence of international transmission trends which reveal costs exceeding inflation.

[39] Régie de l'énergie, D-2018-067, R-4011-2017, June 12, 2018, HQD Phase III Decision, paragraph 178.

Section 3: Off-Ramp (Exit Clause)

A. Introduction

In its Phase I decision, the Régie approved the inclusion of an exit clause to address earnings risk that results either from the design or application of the MRI. The Régie deferred its decision on the specific design of the exit clause for the Carrier to this Phase III.

An off-ramp or exit clause is a PBR design element that protects both customers and the utility against unanticipated financial outcomes, requiring judgment as to the outcomes that would be unacceptable from either the customer or shareholder perspective. It is commonly expressed as a deviation of the actual ROE from the authorized ROE as reported during one of the annual reporting periods in a multi-year PBR.

Once an exit clause is triggered, the PBR plan is usually suspended for review or terminated. The decision to suspend for review or terminate the PBR plan should specify the methodology that will be used to establish the utility's revenue requirements until such time as a modified PBR plan is reinstated.

B. Design Considerations

Although an exit clause provision is expressed in relatively straightforward terms, there are certain design features that must be addressed including the consequences that trigger the exit clause, the earnings shortfall and surplus thresholds, and whether the clause can be triggered by a single year's performance or by performance in more than one year.

1. ROE Threshold Levels

In a PBR plan with an earnings sharing mechanism (ESM),[40] ROE threshold levels must be specified to apply before or after the ESM has been applied. Since the purpose of the off-ramp is focused on the end-result with respect to earnings levels, it is appropriate to establish a threshold level that applies to earnings after applying the MTÉR for HQT.

It is informative to examine the off-ramps from other MRIs along with their respective earnings sharing mechanisms when considering the ROE threshold levels and other design elements to be applied to HQT. We considered two groups of MRIs: Canadian electric utilities with multi-year I-X PBRs that have been decided in the last 10 years (as shown in Table 8), and Canadian gas utilities with multi-year I-X PBRs that have been have been decided during the same period (as shown in Table 9). In both cases, we examined results that were the result of litigated proceedings as well as settlements, as ultimately all plans were approved by the regulator.

[40] The term ESM is used to refer to earnings sharing mechanisms, generally, and the term MTÉR is used to refer to HQT's ESM, as approved by the Régie.

The Canadian precedent is relevant because it reveals how other regulatory commissions and intervenors have addressed similar objectives, including the off-ramp. We included gas utilities, including prior MRI decisions by the Régie, as establishing additional precedent. Concentric considers the electric precedent to be most relevant for HQT given the differences between the two industries. Nonetheless, it is important to be aware of the relevant precedent by the Régie, including natural gas utility precedent.

Table 8: Canadian Electric ESM and Off-ramp Precedent

Province	Company	Decision Type	Plan Term	ESM Parameters	Off Ramp/ Reopener	Note
Alberta	2nd Generation PBR	Fully litigated	2018-2022	None	(1) +/- 300 basis points above/below target ROE for two consecutive years (2) +/- 500 basis points/below target ROE for one year	
Alberta	ENMAX Power Corp.	Fully Litigated	2007-2016	+ 100 basis point deadband; 50/50 sharing thereafter; 100% downside risk to company	Off-ramps • circumstances change in a substantial or unforeseen manner • change in regulatory status •change in EPC control • misrepresentation by EPC Off-ramps would result in the Formula Based Ratemaking (FBR) application being wholly re-opened or terminated. Re-openers • failure to meet a specific performance standard for two consecutive years; • material changes in accounting standards that have an annual impact greater than $5 million; • expansion of EPC's service area where more than 10,000 customers are included within the expanded area; • actual ROE is +/- 300 bps above / below target ROE for two consecutive years; and • actual ROE is +/- 500 bps above / below target ROE for one year. The FBR would only be re-opened to the extent required to address the issue that triggered the re-opening.	(1)
British Columbia	FortisBC (electric)	Fully litigated	2014-2018	Symmetric +/- 50/50 sharing; no deadband	Post ESM earnings +/- 200 basis points for one year Post ESM earnings +/- 150 basis points for two consecutive years	
Ontario	4th Generation Incentive Regulation	Fully litigated	Case-by-case	Case-by-case	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	
Ontario	Toronto Hydro	Fully litigated	2015-2019	+/-100 basis point deadband; 50/50 sharing on upside and downside (non-capital related variances)	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	(2)
Ontario	Horizon Utilities	Settled	2015-2019	50/50 upside sharing; no deadband; downside risk to company	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	(2)
Ontario	Hydro Ottawa	Settled	2016-2020	50/50 upside sharing; no deadband; downside risk to company	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	(2)
(1)	According to the Company, it interprets the application of the off ramp as post-ESM					
(2)	Interpreted as pre-ESM given that this threshold applies to utilities in Ontario that do not have an ESM in their IR framework for two of the OEB's three IR frameworks					

Table 9: Canadian Gas ESM and Off-ramp Precedent

Province	Company	Decision Type	Plan Term	ESM Parameters	Off Ramp/ Reopener	Note
Alberta	2nd Generation PBR	Fully litigated	2018-2022	None	(1) +/- 300 basis points above/below target ROE for two consecutive years (2) +/- 500 basis points/below target ROE for one year	
British Columbia	FortisBC (gas)	Fully litigated	2014-2018	Symmetric +/- 50/50 sharing; no deadband	Post ESM earnings +/- 200 basis points for one year Post ESM earnings +/- 150 basis points for two consecutive years	
Ontario	Enbridge Gas Distribution	Fully litigated	2014-2018	No deadband; 50/50 upside sharing, 100% downside company risk	Pre ESM earnings +/- 300 basis points (weather normalized earnings)	(1)
Ontario	Enbridge Gas Distribution	Settled	2008-2012	+100 basis point deadband; 50/50 sharing thereafter; 100% downside risk to company	Pre ESM earnings +/- 300 basis points (weather normalized earnings)	(1)
Ontario	Union Gas Limited	Settled	2014-2018	+100 basis point deadband; 50/50 sharing for next 100 bps, 10/90 sharing above 200 bps (company/customer)	None	
Ontario	Union Gas Limited	Settled	2008-2012	+200 basis point deadband; >200 basis point 50/50 sharing; >300 bps 10/90 sharing (company/customer)	None	
Québec	Gazifère	Fully litigated	2011-2015	Earnings are conditional on achievement of global service quality indicator: upside only; First 100 basis points: 75/25 company/customer; next 250 basis points: shared 50/50; >350 basis points : 0/100 company/customer;100% downside risk to company.	By Request	
(1)	According to the Company, it interprets the application of the off ramp as pre-ESM					

As shown in Table 8, Canadian electric distribution PBRs have off-ramps that range in terms of basis point thresholds, number of performance years considered, the existence of an ESM, and other conditions under which a plan may be terminated. The off-ramp must be considered in conjunction with the ESM, plan term, and authorized ROE. Off-ramps are not always expressed in terms of ROE thresholds.

Two of the electric plans examined have ESMs that incorporate a deadband. The two generic plans (Alberta and Ontario) do not have an ESM, but have varying off-ramps that differ in terms of performance years considered and basis point thresholds (±300 basis points for one year in Ontario, or ±500 basis points for one year in Alberta).

As shown in Table 9, similar trends emerge for Canadian gas distributors. Three of the seven gas PBRs listed above have a deadband, while three have some level of immediate sharing, and one has no ESM. Gas distribution PBR off-ramps also vary in terms of basis point thresholds, number of performance years considered, and other performance conditions.

One consideration in establishing the ROE threshold for HQT is that the Carrier has a lower authorized ROE than other Canadian electric, gas and transmission utilities. Each basis point differential represents a larger percentage of earnings with respect to shortfalls and surpluses. As shown in Table 10, HQT's ROE is 30 basis points below the average ROE for Canadian transmission companies. Similarly, its equity ratio is lower than the average equity ratio for these same companies. This supports a lower threshold than might otherwise be appropriate to achieve a comparable percentage of earnings at risk.

Table 10: Comparison of Authorized ROEs

Authorized Rate of Return on Common Equity & Equity Ratio (%) 2017		
	ROE	Equity Ratio
Electric Distribution		
ATCO Electric Ltd.	8.50	37.00
ENMAX Power Corporation	8.50	37.00
EPCOR Distribution Inc.	8.50	37.00
FortisAlberta Inc.	8.50	37.00
FortisBC Inc.	9.15	40.00
Hydro-Québec Distribution	**8.20**	**35.00**
Manitoba Hydro	*n/a*	25.00
Maritime Electric Company Limited	9.35	40.00
Newfoundland and Labrador Hydro	8.50	25.20
Newfoundland Power Inc.	8.50	45.00
Nova Scotia Power Inc.	9.00	37.50
Ontario's Electricity Distributors	9.00	40.00
Saskatchewan Power Corporation	8.50	40.00
Average	**8.68**	**36.59**
Electric Transmission		
AltaLink Management Ltd.	8.50	37.00
ATCO Electric Ltd.	8.50	37.00
ENMAX Power Corporation	8.50	37.00
EPCOR Transmission Inc.	8.50	37.00
Hydro One Networks Inc.	8.78	40.00
Hydro-Québec TransÉnergie	**8.20**	**30.00**
Average	**8.50**	**36.33**
Natural Gas Distribution		
AltaGas Utilities Inc.	8.50	41.00
ATCO Gas	8.50	37.00
Centra Gas Manitoba Inc.	*n/a*	30.00
Enbridge Gas Distribution Inc.	8.78	36.00
Enbridge Gas New Brunswick	10.90	45.00
FortisBC Energy Inc.	8.75	38.50
Gaz Métro Limited Partnership	8.90	38.50
Gazifère inc.	9.10	40.00
Heritage Gas Limited	11.00	45.00
Pacific Northern Gas Ltd.	9.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.25	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	9.50	46.50
SaskEnergy Inc.	8.30	37.00
Union Gas Limited	9.00	36.00
Average	**9.23**	**39.86**

The off-ramp threshold should also reflect the asymmetry of upside and downside sharing under the MTÉR. This is particularly appropriate in HQT's MTÉR because its design is asymmetric with the Carrier absorbing 100% of earnings shortfalls but shares earnings surpluses with customers under a two-step sharing mechanism. The first 100 basis points of surplus earnings are shared equally between HQT and customers. Earnings surpluses above 100 basis points are shared 75 (customer)/25 (shareholder) in the second step. The HQT MTÉR design reinforces the appropriateness of a lower threshold to recognize the asymmetric sharing of downside and upside earnings by HQT.

Concentric Recommendation: The off-ramp should be established with reference to HQT's earnings after the MTÉR has been applied. The off-ramp focuses on bottom line results and seeks to avoid extraordinary surpluses or shortfalls that could not have been anticipated when the MRI plan was adopted. A symmetric off-ramp is appropriate in order to provide the same level of protection to customers and the shareholder. In terms of establishing the size of the off-ramp, it is particularly important to avoid earnings shortfalls that would cause financial distress as this will harm customers as well as the shareholder.

Based on these factors, and the evidence above, Concentric recommends an exit clause with a symmetric off-ramp of ±150 basis points after any earnings sharing provided for by the application of the MTÉR, recognizing that HQT will continue to absorb all of earnings shortfalls under the existing MTÉR. Based on application of HQT's existing MTÉR, this is equivalent to a 500 basis point upside off-ramp for a utility that either does not have an ESM or expresses the off-ramp with reference to earnings before the ESM is applied. This is consistent with the application of the one-year off-ramp in Alberta on the upside. Of course, if HQT were to earn an unprecedented 500 basis point surplus, customers will receive 350 basis points of this surplus through application of the MTÉR (50% of the first 100 basis points and 75% of the next 400 basis points).

The following table illustrates the number of basis points of over/under earnings that would trigger the off-ramp under the existing MTÉR framework.

Table 11: Over and Under Earnings when Off-ramp is Triggered

HQT Earnings Scenario Using 2017 Rate Base and Approved ESM Parameters

	Company / Customer (%)	Bps
Downside Sharing	100 / 0	< 0
First Tier	50 / 50	0 < 100
2nd Tier	25 / 75	> 100

Rapport Annuel 2017, HQD-2, document 3.1	Rate Base ($000)	$ 19,463,115
	Equity Percent	30.0%
	Authorized ROE	8.2%
	Operating Earnings ($000)	$ 478,793
	Authorized ROE (bps)	820
	Earnings per Basis Point ($000)	$ 584

150 bps Off Ramp			Company ($000)		Customer ($000)	Company bps	Customer bps
Downside	0 to -150 bps	$	(87,584)	$	-	-150	0
Total Upside Over Earnings (pre-sharing)		$	291,947			500	
First Tier	0 to 100 bps	$	29,195	$	29,195	50	50
2nd Tier	> 100 bps	$	58,389	$	175,168	100	300
Total Upside Over Earnings (post-sharing)		$	87,584	$	204,363	150	350

As illustrated in Table 11, the exit clause is triggered when pre-sharing earnings reach 500 basis points on the upside and 150 basis points on the downside. However, the triggers are identical at ±150 basis points when the comparison is based on post-sharing earnings, the relevant measure when considering the off-ramp's purpose. An examination of HQT's actual earnings over the past 11 years indicates that these thresholds would not have been reached, suggesting that the triggers are realistic.

2. Performance Period

There are a few examples in which regulators have approved off-ramps where two consecutive years be required to trigger an exit clause. The consecutive year triggers are generally less than the single-year trigger, as seen for example in FortisBC's off-ramp (e.g., post-ESM earnings of +/- 200 basis points for one year, or post-ESM earnings of +/- 150 basis points for two consecutive years).

Concentric's single year recommendation considers the fact that HQT's MRI will have three indexed years following the first cost of service year. Thus, a two-year trigger mechanism is unlikely to have any practical application. A multi-year off-ramp (2 years or more), would be too long to have any practical impact during the index plan period. The plan could be expired and up for review by the time a two-year threshold was achieved, so it would offer no real protection for customers or HQT. This is an unnecessary complication for a first-time MRI with a four-year term.

Concentric Recommendation: the exit clause trigger for this initial MRI plan should be based on a single year's performance, calculated using the most recent calendar year to correspond with the annual earnings reporting period.

3. Consequences of Triggering the Exit Clause Provision

A triggering of the exit clause provision will typically result in a termination of the MRI and a return to the existing revenue requirements framework, which for HQT establishes revenue requirements for the upcoming year based on a forecast of the cost of service. A termination does not preclude a reconsideration of the entire MRI design but recognizes that a broad reconsideration of the MRI plan is likely to take an extended period.

Concentric Recommendation: The exit clause should result in a termination of the MRI plan and a reversion to the existing forecasted cost-of-service revenue requirements framework. In HQT's case, it would be appropriate to revert to a forecasted cost-of-service methodology.[41]

C. Summary of Off-Ramp Recommendations

Concentric recommends the following with respect to the design of the exit clause as an integral component of HQT's MRI plan:

- The exit clause should reflect a symmetric design of ±150 basis points, after any earnings sharing provided for by the application of the MTÉR, reflecting the fact that HQT will continue to absorb 100% of earnings shortfalls under the existing MTÉR mechanism;
- The exit clause trigger should be based on a single year's performance, with earnings based on the most recent earnings reporting period; and
- The exit clause should result in a termination of the MRI plan and a reversion to the existing revenue requirements framework based on a forecasted cost-of-service methodology.

[41] It would be necessary to establish an interim revenue requirement until such time as a new revenue requirement could be established.

Section 4:
Parametric Formula for Capex

A. Introduction

In accepting HQT's proposal to maintain Capex outside of the indexation formula and treat them on a cost of service basis, the Régie directed the Carrier to propose a hypothetical non-binding parametric formula for Capex.[42] She states that in doing so, it will then be possible to compare the level of Capex that the Carrier will recover through rates during this first-generation MRI to the level of Capex generated by the hypothetical parametric formula.[43] Concentric has previously addressed the difficulty of applying a multi-year formula to capital related revenue requirement the year-to-year variability of these costs. These challenges include the fact that the capital budgets of transmission companies tend to be dominated by large, multi-year construction projects and can vary widely from year-to-year. Further, many of the projects in recent years are intended to connect renewable resources and are not necessarily related to the factors that are part of a parametric formula. Finally, in the case of HQT, the asset management model (MGA) is specifically designed to determine the optimal level of Capex and its results should be incorporated into the determination of Capex in some way.

Concentric identified three "formulaic" approaches to capital that have been adopted in other jurisdictions to determine their effectiveness for HQT and their responsiveness to the Régie's directive described above. The first approach is that approved by the Ontario Energy Board (OEB) for Toronto Hydro in its most recent Custom IR plan.[44] The second approach is that approved by the British Columbia Utilities Commission (BCUC) for Fortis BC in its current performance-based regulation plan, approved in 2014.[45] The third approach is the "smoothing method" employed by the AER.[46]

B. Toronto Hydro

In the most recently approved PBR plan for Ontario's electric distributors (which does not include transmission companies that currently remain under cost of service), utilities were provided with three options: the 4th Generation IR price cap index; a Custom IR plan, or an Annual IR index.[47]

Toronto Hydro operates under a custom IR price cap with a custom treatment of capital. The Toronto Hydro method employs a custom capital factor or "C" factor, which is calculated on a percentage basis and added to the other components of the indexation formula (I, X, g, etc.). When added together, these formula components become the escalation rate by which Toronto Hydro's rates grow. Certain components of the escalation factor, or the CPCI as it is known in Toronto Hydro's model, are updated annually including the capital factor. The following tables are taken from a Toronto Hydro compliance filing and demonstrate the process by which the C factor is calculated.[48]

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42 D-2018-001, paragraph 296.
43 D-2018-001, paragraph 297.
44 Ontario Energy Board Decision and Order EB-2014-0116, Toronto Hydro Electric System Limited, December 29, 2015.
45 British Columbia Utilities Commission. In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018. Decision September 15, 2014.
46 See, for example, Final Decision for Powerlink Transmission determination 2017-2022, April 2017.
47 Report of the Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 18, 2012, p. 13.
48 Toronto Hydro Electric System Limited, Update to the Draft Rate Order EB-2014-0116, February 29, 2016.

Table 12: Toronto Hydro Calculation of Annual Capital Factor (C factor)

	2015	2016	2017	2018	2019
Interest	79.3	87.7	95.4	99.9	104.3
ROE	120.2	133.0	144.7	151.6	158.2
Depreciation	206.0	218.7	242.2	257.7	275.0
PILs/Taxes	25.0	16.9	24.3	40.2	45.7
Capital-related RR	430.5	456.3	506.6	549.4	583.2
OM&A	243.9	247.6	251.3	255.1	258.9
Revenue Offsets	(41.3)	(41.9)	(42.5)	(43.2)	(43.8)
Total RR	633.1	662.0	715.4	761.4	798.3
C_n		4.07	7.60	5.99	4.43

	2016	2017	2018	2019
I	2.1	2.1*	2.1*	2.1*
X – Productivity	(0.0)	(0.0)	(0.0)	(0.0)
X – Stretch	(0.6)	(0.6)	(0.6)	(0.6)
C_n	4.07	7.60	5.99	4.43
S_{cap}	68.9	70.8	72.2	73.1
G	(0.3)	(0.3)	(0.3)	(0.3)
CPCI	3.83	7.32*	5.67*	4.10*

Where:

I	The inflation factor based on the OEB's methodology; updated annually
X	The sum of the productivity and stretch factors based on the OEB's methodology with one exception; the stretch factor is set at 0.6% for the term of the plan and not updated annually
G	The growth factor value set at 0.3% for the term of the plan
Cn	The capital factor value update annually = (Capex RR_{t+1} – Capex RR_t)/ Total RR_t
Scap	The Capex scale factor updated annually = Capex RR / Total RR
C	= Cn – (I * Scap)
CPCI	= I – X – G + C

The capital factor is determined by calculating the incremental difference in forecasted capital-related revenue requirement between the current year and the prior year. When (Scap * I) is subtracted from this calculation, the C factor is then offset for the incremental funding for capital that would have been provided under the standard price cap index adjustment to base rates.[49] The Scap is equal to the proportion of total revenue requirement that is capital related, on a forecasted basis.

This approach means that capital expenditures become embedded in the escalation formula, despite the fact that they are preapproved by the OEB. Application of this approach to HQT's MRI would require a forecast of capital related revenue requirements for the 4 year plan period. HQT would report and compare actual results with its annual compliance filing. This approach would require additional filings with the Régie and may be counter to the objective of regulatory streamlining.

C. FortisBC Inc.

In the most recent decisions for FortisBC Inc. (FBC, the electric utility) and FortisBC Energy Inc. (FEI, the gas utility), the BCUC approved capital adjustment mechanisms for both companies in their 5-year PBR plans.[50] FBC operates under a five-year revenue cap with a carve out for some capital, exogenous and flow through items.

In its decision, the Commission identified the following issues pertaining to capital:

1. What is the appropriate base capital upon which to base the formula?
2. What proportion of capital spending should be included? What, if any, capital projects should be excluded from the formula?
3. How can capital expenditures, which are often lumpy, be appropriately matched to a much less lumpy formula driven spending envelope?
4. How can the ratepayer be protected from chronic underspending relative to the formula driven spending envelope?
5. How can Fortis be protected in the event that necessary capital expenditures drive the actual capital expenditures above the formula driven spending envelope?[51]

[49] Ontario Energy Board, Decision and Rate Order for Toronto Hydro Electric System Limited, EB-2017-0077, December 14, 2017, p. 5.
[50] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018, September 15, 2014.
[51] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018, September 15, 2014, p. 159.

Prior PBR plans for the companies had different approaches to capital. For FBC, prior to 2004, PBR covered only O&M, and all capital spending was approved separately. For FEI, over the 2005-09 PBR plan, smaller capital expenditures were included in the I-X formula, but larger "CPCN" (Certificate of Public Convenience and Necessity) projects (those greater than $5M) were addressed in separate regulatory processes. For FBC, a CPCN is required for projects greater than $20M.

In the current program, the Commission determines an amount of "Base Capital" spending from the starting point year prior to the first PBR year (in this case, 2013). The remaining capital-related revenue requirement is excluded from the formula and added back to the total revenue requirement. Base capital is escalated according to I-X including a growth factor.

This base capital is broken down to three primary categories comprised of Sustainment Capital, Growth Capital (primarily for new connects), Other Capital, and provincial sales tax and pension adjustments (capital portion):

- "Sustainment Capital" – Consists of expenditures for system reinforcements, replacements and upgrades to generation, transmission and distribution assets to ensure safety, integrity and reliability.
- "Growth Capital" – Consists of expenditures for infrastructure upgrades required to meet customer and associated load growth.
- "Other Capital" – Consists of expenditures for information systems, vehicles, metering, telecommunications, facilities, and tools and equipment.

Under the PBR plan, changes in approved capital expenditures follow a formulaic approach, as illustrated below:[52]

[52] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018, September 15, 2014, p. 206.

Table 13: FBC PBR Capital Formula Inputs and 5-Year Forecasts

Line No.	Particulars	2013 Base	2014 Formula	2015 Formula	2016 Formula	2017 Formula	2018 Formula
		(1)	(2)	(3)	(4)	(5)	(6)
1	**2013 Base Capital ($000)**	$ 49,180					
2	Less Capital Tracked Outside of Formula						
3	Pension/OPEB (Capital portion)	(6,741)					
4		42,439					
5							
6	Average Number of Customers	128,796	129,770	130,922	132,142	133,385	134,687
7	% Change in Customers		0.76%	0.89%	0.93%	0.94%	0.98%
8							
9	Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
10							
11	Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
12							
13	I-X Mechanism (1+I-X)		101.81%	101.92%	101.84%	101.86%	101.80%
14							
15	Net Inflation Factor ((1 + Line 7) * Line 13)		102.58%	102.82%	102.79%	102.82%	102.79%
16							
15	**Formulaic Capital (Line 15 * Prior Year)**		43,534	44,764	46,012	47,309	48,630
16	Add: Capital Tracked Outside of Formula						
17	Pension/OPEB (Capital portion)	6,741	6,396	5,952	5,508	5,133	4,826
18	PCB Compliance - Substations		6,062				
19	Advanced Metering Infrastructure Project		16,765	18,233	583	741	604
20							
21	**Total Capital Under PBR**		72,758	68,950	52,103	53,183	54,060

(Source: Exhibit B-1, p. 58)

The "growth factor" shown in line 7 is determined by the change in customers, and it applies to all included capital. The growth factor was ultimately multiplied by 0.5 in the final decision.[53]

The plan also includes an allowance for projects outside of the indexation formula. Those projects are excluded from the PBR formula and added to ratebase with full cost recovery once placed into service on a flow-through basis, net of any offsetting O&M or revenue effects. The CPCN threshold ($20M for FBC) was used initially, subject to further submissions by the parties. In a subsequent Order, the BCUC determined the materiality thresholds to be $20M for FBC and $15M for FEI and ruled that smaller projects should not be combined to achieve that threshold.[54]

Another aspect of the BC decision is a deadband around capital spending. If the company under (or over spends) its capital under the formula by 10% in a single year, or 15% in two years, the companies are required to file recommendations for adjustments to base capital for the remainder of the PBR term.[55]

In order to apply this model to HQT, the Company's capital related investments would have to be sorted into base and non-base categories. This approach would again require additional filings with the Régie to justify base and non-base categories, and may be counter to the objective of regulatory streamlining.

53 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018, September 15, 2014, p. 118-119.
54 BCUC Order G-120-15, July 22, 2015, p. 2.
55 BCUC Order G-120-15, July 22, 2015, APPENDIX A to Order G-120-15, p. 17 of 18.

D. Australia

As discussed previously, the AER regulates transmission companies using a forecasted building block approach over a five-year term. While the overall level of revenue requirement is affected by the AER's assessment of each company's Capex forecast, the annual revenue requirement is "smoothed" from year to year. An "X factor" is generated from the year-to-year change in revenue requirement and provides an indication of how revenues will increase relative to inflation. The table below shows the final revenue requirement determination for Powerlink Transmission.

Table 14: AER's Final Decision on Powerlink's Revenues ($million, nominal)

	2017–18	2018–19	2019–20	2020–21	2021–22	Total
Return on capital	425.5	430.4	434.2	437.3	440.5	2168.0
Regulatory depreciation[a]	88.9	113.3	131.0	143.1	150.2	626.6
Operating expenditure[b]	201.7	205.8	209.8	214.2	219.3	1050.7
Revenue adjustments[c]	–0.8	–7.1	–3.2	3.0	0.0	–8.1
Net tax allowance	17.1	19.4	22.7	24.3	24.5	108.0
Annual building block revenue requirement (unsmoothed)	732.4	761.8	794.6	821.9	834.5	3945.2
Annual expected MAR (smoothed)	**752.7**	**770.0**	**787.6**	**805.7**	**824.2**	**3940.2**[d]
X factor[e]	n/a[f]	0.15%	0.15%	0.15%	0.15%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Operating expenditure includes debt raising costs.

(c) Includes efficiency benefit sharing scheme amounts.

(d) The estimated total revenue cap is equal to the total annual expected MAR.

(e) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(f) Powerlink is not required to apply an X factor for 2017–18 because we set the 2017–18 MAR in this decision. The MAR for 2017–18 is around 27.9 per cent lower than the approved MAR for 2016–17 in real terms, or 26.1 per cent lower in nominal terms.

Adoption of the Australian approach, similar to the Toronto Hydro model, would require a capital related forecast for the term of the MRI, and Régie approval of such a forecast. As stated in the case of Toronto Hydro, this would require additional filings and be counter to the objective of regulatory streamlining.

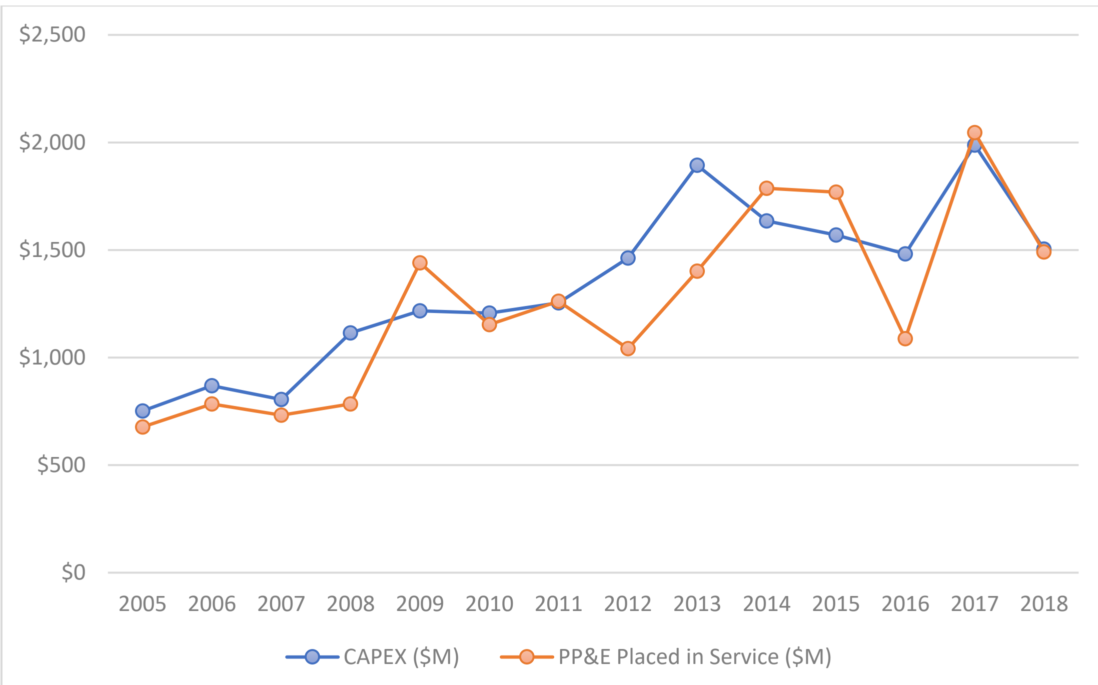
E. Design considerations for HQT

Recognizing the specific challenges of managing varying capital charges under an I-X program, regulators including the Régie have adopted provisions that provide more flexibility for recovering incremental capital-related costs under PBR plans.

A formula that tracks capital related revenue requirement for HQT must take into account the capital-intensive nature of its business and the fact that Capex is often "lumpy," and influenced by large projects over many years that are often dictated by system requirements and beyond the complete direct control of the Company.

HQT's capital expenditures are driven by a combination of: replacement of its aging infrastructure, growth in customer demand or integration of new generation resources, improvements in service quality, or external requirements (e.g., NERC or governmental regulations). Total capital related expenditures and capital placed in service vary considerably from year-to-year, depending on the mix of projects.

Figure 4: HQT's Capex and Property, Plant & Equipment (PP&E) Placed in Service (2005-2018) [56]



There are considerations associated with each approach described above, and it is worth recognizing that two of these three approaches apply to distribution companies. While a parametric formula may be suitable, in some cases, for certain types of distribution-related capital, it is less likely to be successful for a transmission company. Distribution company capital projects are dominated by groups of small projects, some of which can be deferred within a year to meet a revenue limitation without having an impact on reliability or service quality. This is not the case for transmission projects, where projects are much larger and the consequences of an unplanned outage have a greater impact on reliability. The following summarizes each approach evaluated.

[56] Capex and PP&E 2005-2018: Company provided data;
2018 = forecast year.

Toronto Hydro Approach

- The Toronto Hydro approach allows for capital related revenue requirements to become embedded in the escalation formula, because they are pre-approved by the OEB.
- This approach allows for year-to-year variation in the implied X factor, and therefore the escalation rate, to accommodate capital that does not necessarily conform to a linear index.
- Should the Régie find the Toronto Hydro approach reasonable, the formula would need to be adjusted for consideration of the fact that Toronto Hydro operates under a price cap, and HQT will operate under a revenue cap. This distinction requires a different treatment for growth.
- The resulting escalation rate creates an incentive for optimizing both Opex and Capex covered under the formula, but requires a multi-year forecast of Capex-related revenue requirement, which would be difficult to generate and approve at the immediate outset of the HQT plan.

FortisBC Approach

- The FBC approach imposes an external index (I-X including growth) on a carve out of FBC's capital related revenue requirement.
- This type of formula would allow the Régie to track formulaic-allowed capital compared to actual capital related revenue requirement. This would allow the Régie to "test" whether or not capital related revenue requirements (or some portion of them) are linear enough over a 4-year term to be accommodated under an index.
- If adopted, HQT would need to track the capital-related revenue requirements of those projects included in the index to compare the efficacy of the formula after-the-fact.
- Large projects or non-recurring special projects could be tracked separately allowing for inclusion of more costs under the incentive formula.
- This approach is similar to that adopted in Alberta.

AER Approach

- Similar to the Toronto Hydro approach, the AER approach allows for capital related revenue requirements to become embedded in the escalation formula, because expenditures are pre-approved by the AER.
- Unlike the Toronto Hydro approach, in Australia the year-to-year revenues are smoothed over the term of the plan and an implied overall escalation factor is derived from pre-approved revenue requirements.
- Such an approach would require a capital forecast for the rate period, including total and capital-related revenue requirements to compare to actuals.

F. Recommended Approach for HQT

As discussed in Concentric's Phase I evidence, a parametric formula inclusive of capital is a poor fit for HQT. Recognizing the Régie's directive in D-2018-001, Concentric recommends that a parametric formula for capital-related revenue requirement based on the FortisBC model would be most responsive. This approach would allow the Carrier the opportunity to track its hypothetical formulaic capital relative to what is approved in rates in this first-generation MRI. Performance of the capital-related parameter can be improved with careful determination of "base capital" revenue requirements that are most likely to follow a parametric trend. However, given the additional filings that would be necessary to distinguish base capital from non-base capital and the additional regulatory burden created, this first application of a parametric formula for Capex could be applied to all capital-related revenue requirement. This approach is simplest in application, is the most responsive to the Régie's directive, and avoids undue regulatory burden that is counter to the objectives of Article 48.1.

Section 5:
Conclusions and Summary of Recommendations

Concentric has reviewed the regulatory treatment of transmission companies operating under performance or incentive-based regulation in various international jurisdictions, as well as HQT's own historical productivity. We have also reviewed precedent for off-ramps for Canadian PBR plans. Finally, Concentric has reviewed and presented several formulaic approaches for the treatment of capital under incentive ratemaking plans. Based on this review and the analysis presented above, Concentric concludes and recommends the following:

X Factor

- Based on a combination of HQT's actual experience with the costs covered by the CNE component of the MRI formula and industry research, Concentric recommends an X factor of -0.6%.

Off-Ramp

- The exit clause should reflect a symmetric design of ±150 basis points, after any earnings sharing provided for by the application of the MTÉR, reflecting the fact that HQT will continue to absorb 100% of earnings shortfalls under the existing MTÉR mechanism;
- The exit clause trigger should be based on a single year's performance, with earnings based on the most recent earnings reporting period; and
- The exit clause should result in a termination of the MRI plan and a reversion to the existing revenue requirements framework based on a forecasted cost-of-service methodology.

Parametric Formula for Capex

- Despite the fact that a parametric formula inclusive of capital is a poor fit for HQT, recognizing the Régie's directive, Concentric recommends that a parametric formula for capital-related revenue requirement be based on the FortisBC model;
- I, X, and growth factors could be specified separately for capital-related revenue requirements;
- Tracking different types of capital would introduce more regulatory burden but would better conform to the approach taken in British Columbia; and
- This approach is simplest in application, is the most responsive to the Régie's directive, and avoids undue regulatory burden that is counter to the objectives of Article 48.1.