Incentive Rate-Setting for Hydro One Transmission and Distributor Services

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1. Introduction and Summary

1.1. Introduction

In its August 2021 joint rate application, Hydro One Networks ("Hydro One" or "the Company") proposed a new Custom Incentive Rate-Setting ("CIR") framework for its power transmission and distributor ("T&D") services.[1] The framework involves multiyear rate plans that would apply over the five years from 2023 to 2027. Following a rebasing of transmission and distributor rates for 2023, for the period from 2024 to 2027, in each plan, growth in a revenue cap index ("RCI") would be tied to inflation but slowed by a Productivity Factor ("X") that is the sum of a base productivity growth target and a stretch factor. A Custom Capital Factor ("C") would ensure recovery of substantially all forecasted/proposed capital costs if they were actually incurred.[2]

The proposed X factors are supported by transmission productivity and transmission and distributor ("T&D") cost benchmarking research by Clearspring Energy Advisors, Inc. ("Clearspring"), a Madison, Wisconsin consulting firm.[3] The author of Clearspring's report, Steve Fenrick, prepared similar studies in prior Hydro One proceedings as an employee of Power Systems Engineering.

Hydro One's Custom IR evidence merits careful examination in this proceeding for several reasons.

- Hydro One is Ontario's largest power distributor and provides virtually all transmission services in the province.
- Custom IR has proven to be a controversial approach to ratemaking.
- The stretch factor has an impact on capital cost containment incentives.

[1] EB-2021-0110.

[2] While the revenue cap index formula ensures pass-through of forecasted in-service capital additions, a separate Capital In-service Variance Account would true-up after 2027 (i.e., after the term of the plan) for planned in-service additions not executed over the plan term.

[3] Fenrick, Steve, "Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application," Exhibit A-4-1/Attachment 1, filed 5 August, 2021.

- Hydro One proceedings have become an important occasion to consider the statistical cost research methods used in Ontario energy rate regulation.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. Incentive rate-setting ("IR") for power T&D services are company specialties. We have done several power transmission productivity and benchmarking studies and have played a prominent role in the development of IR for power transmission in Québec as well as Ontario. Ontario Energy Board ("OEB") Staff have retained PEG to consider and respond to Clearspring's evidence and the Company's IR proposals.

This is our report on this work. Following a brief summary of our findings, Section 2 provides a summary of Hydro One's proposal. Section 3 provides our critique of Clearspring's transmission research and testimony. Section 4 discusses results of transmission productivity and benchmarking research by PEG using alternative methods. Section 5 provides our critique of Clearspring's distributor cost benchmarking research and testimony. Section 6 discusses distributor productivity and benchmarking results by PEG. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses some methodological issues in the research in more detail. Appendix C discusses pertinent features of North America's power transmission industry. Appendix D discusses the evolution of Hydro One ratemaking and Custom IR. A brief discussion of PEG's credentials is provided in Appendix E.

1.2. Summary

Empirical Issues: Transmission

Clearspring developed an econometric model of total power transmission cost using operating data for United States ("U.S.") utilities over the 2000-2019 period. This model was used to benchmark the total cost that Hydro One incurred over the 2003-2019 historical period and the Company's forecasted/proposed cost over the 2020-2027 period. Clearspring also calculated the multifactor productivity ("MFP") trends of 50 U.S. electric utilities in the provision of transmission services from 2000 to 2019.

U.S. Transmission Productivity Trends

Clearspring reported that the sampled U.S. transmitters averaged a 1.66% annual MFP decline over their full 2001-2019 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged a 2.30% annual decline while capital productivity averaged a 1.50% decline. Clearspring nevertheless recommends a 0.00% base productivity trend for the transmission revenue cap index, and Hydro One embraced this proposal. The 1.66% difference between zero and the calculated transmitter MFP trend is portrayed as an implicit stretch factor.

Our review of Clearspring's productivity research raised the following major concerns.

- The 2001-2019 sample period that Clearspring featured in its productivity research was one during which U.S. power transmission productivity was adversely influenced by special circumstances that included the Energy Policy Act of 2005. The Federal Energy Regulatory Commission ("FERC") was given jurisdiction to oversee reliability standards organizations and to approve mandatory reliability standards. Incentives to contain cost were weakened by special investment incentives and by FERC-administered formula rate plans under which a growing number of transmitters operated. Some transmitters made investments to access remote renewable resources and improve the functioning of bulk power markets. It is not at all clear that the productivity growth challenges faced by U.S. transmitters during this period are comparable on balance to those that Hydro One Transmission currently faces and will face in the next few years.
- Clearspring's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities joined independent transmission system operators ("ISOs") or regional transmission organizations ("RTOs"), and this seems to have triggered idiosyncratic reporting of OM&A expenses of some members. In our view, data for some of the affected companies should be excluded from the research.

PEG's contract with OEB Staff for work in this proceeding does not include new productivity research. We believe that the most pertinent research on the productivity trends of U.S. power transmitters was reported by PEG in a recent proceeding of the Régie de l'énergie in Québec.[4] This research used a longer sample period than Clearspring's and was free of other problems we discuss in this report. Over the full 1996-2019 period, we reported that sampled transmitters averaged -0.62% multifactor productivity growth and -0.68% growth in the productivity of OM&A inputs.

Hydro One's Transmission Cost Performance

Clearspring reported Hydro One's transmission cost performance to be exceptionally good throughout the lengthy sample period that they considered albeit declining over time. The Company's total transmission cost was a substantial 46.6% below the benchmarks from Clearspring's econometric cost model on average over the 2018-2020 period. The Company's forecasted/proposed total cost was 34.5% below the econometric benchmarks during the years of the proposed IRM (2023-2027). The Company's cost efficiency would decline by an average of 1.88% annually between 2023 and 2027.

Our chief concerns about Clearspring's transmission benchmarking work include the following:

- Several companies with implausible transmission OM&A data were included in the study.
- Inappropriate measures of peak load, substations, and the potential for scope economies were used.
- Clearspring did not provide itemized results for Hydro One's transmission OM&A or capital cost performance.

These and other concerns prompted us to develop an alternative econometric total cost benchmarking model while relying chiefly on the Clearspring data. We also developed econometric benchmarking models for capital cost and OM&A expenses ("opex"). These models are sensible (e.g., in terms of explanatory variables, coefficient signs and functional forms) and generate results that should be informative to the OEB, the Company, and other stakeholders.

The results of our alternative total transmission cost benchmarking were quite different from those of Clearspring. Hydro One's total transmission cost was found to be about 7% above our

[4] Lowry, Mark N., "Transmission Productivity and Benchmarking Study," filed in Règie de l'ènergie, R-4167-2021, as exhibit C-AQCIE-CIFQ-0009, 15 February 2021.

benchmarks on average during the three most recent years for which the requisite historical data were available (2017-2019). Hydro One's forecasted/proposed total costs were about 14% above our model's predictions on average during the five years of the proposed new IR plan (2023-2027). The decline in the Company's total cost efficiency would average 1.12% annually between 2023 and 2027.

Hydro One's transmission capital cost was found to be about 6% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 19% above our benchmarks on average during the five years of the proposed new IR plan.

Hydro One's transmission opex was found to be about 36% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed opex is about 7% above our model's prediction on average during the five years of the proposed new IR plan. This is a noteworthy improvement.

Stretch Factor

We disagree with Clearspring's 0% stretch factor recommendation. One reason is that we do not get such favorable benchmarking results for Hydro One Transmission. Another is that we believe that a supplemental stretch factor is warranted to adjust for the unusually weak cost containment incentives that many U.S. transmitters experienced in some years of the sample period. We recommend a 0.75% stretch factor that is the sum of a 0.45% base stretch factor and a 0.30% supplemental stretch factor.

X Factor Recommendation

Our research supports a **-0.62%** base productivity trend, drawn from our Québec transmission MFP research for the full sample period, and a **0.75%** stretch factor. The resultant X factor would be 0.13%.

Empirical Issues: Distribution

Hydro One's Distribution Cost Performance

Clearspring developed an econometric model of total power distributor cost using operating data from 81 U.S. electric utilities over the 2000-2019 period. This model was used to benchmark the total cost of base rate inputs which Hydro One Distribution incurred over the historical 2003-2019 period, as well as the Company's forecasted/proposed cost over the 2020-2027 period.

Clearspring reported Hydro One's total distributor cost performance to have been good in the early years of its sample period but to have trended downward over time. The Company's forecasted/proposed total cost is 7% above Clearspring's benchmarks during the years of the proposed CIR plan (2023-2027). Using guidelines established by the OEB for Price Cap IR stretch factors, Clearspring recommends a stretch factor of 0.30%.[5]

Despite our agreement with Clearspring on many methodological issues, we disagree with some of the methods used in their distribution cost benchmarking study. Here are some of our larger concerns.

- Clearspring does not use a plausible value for the area of Hydro One, and this is an important variable in their cost model.
- The substation and scope economy data used in the study were flawed.
- We believe that it desirable to go beyond econometric total cost benchmarking in Custom IR proceedings by benchmarking OM&A and capital costs.

PEG developed a total distributor cost benchmarking model using alternative methods but relying chiefly on Clearspring's data. We found that Hydro One's total distributor cost was about 35% above our benchmark on average during the three most recent historical years. Its projected/proposed total cost is about 37% above our benchmarks on average during the five years of the proposed plan. The Company's total cost efficiency would average a 1.38% annual decline from 2023 to 2027.

PEG also developed models to evaluate Hydro One's projected/proposed distributor opex and capital cost. Hydro One's distributor opex was found to be about 5% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed opex is about 7% below our model's prediction on average during the five years of the proposed new IR plan.

[5] Exhibit 1/Tab 1/Schedule 12/Attachment A, p. 8. See also 1.0-VECC-8, OEB-10 b) and OEB-13.

Hydro One's distributor capital cost was found to be about 65% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 72% above our model's prediction on average during the five years of the proposed new CIR plan. It follows that the Company's high capital cost is chiefly responsible for its poor total cost performance.

On the basis of our research, we believe that a 0.60% stretch factor is appropriate for Hydro One's distributor services. Assuming a 0% base MFP trend, we recommend an X factor of 0.60% for these services.

Scale Escalator

Cost theory and index logic support use of a scale escalator in a revenue cap index. It would be reasonable for Hydro One to add a customer growth term to their revenue cap index formula. This would reduce the need for a C factor.

Other Plan Design Issues

We are concerned about some other features of Hydro One's proposal. The proposed ratemaking treatment of capital cost is our chief concern.

- Incentives to contain capex would be weakened by the proposed C factor, Capital In-Service Variance Account ("CISVA"), other capital cost variance accounts, and the Z factor provisions of the revenue cap index. The Company is perversely incented to spend excessive amounts on capital in order to trim OM&A expenses. The weak incentives to contain capex violate the spirit of the Board's Custom IR guidelines and are all the more worrisome given the capital-intensive nature of power transmission technology.
- Notwithstanding the CISVA, Hydro One is still incentivized to exaggerate its need for supplemental capital revenue. The regulatory cost for the OEB and stakeholders is substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.
- While customers must fully compensate Hydro One for the bulk of expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return

any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.

- The kinds of capex accorded C-factor and variance account treatment are, for the most part, conventional T&D capex like that incurred by transmitters in studies used to calibrate base productivity trends. The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.
- The RCI would effectively apply chiefly to the (modest) revenue for OM&A expenses and provide only a floor for revenue growth, even though it is not designed to play either of these roles.

We discuss several possible upgrades to the ratemaking treatment of capital cost in Section 6 of the report. It seems desirable to consider how to make Custom IR more streamlined, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors. Utilities should be encouraged to not stay on Custom IR indefinitely.[6] As discussed further below, regulators in other jurisdictions (e.g., Alberta and Britain) who championed IR but found themselves saddled with a system that retained too many cost of service features have reconsidered and reformed IR at the end of each round of plans.

The other reforms discussed in the report range from evolutionary measures such as an incentivized capital variance account to larger departures from the Board's recent Custom IR approaches, such as those used in Alberta and California. Having considered the pros and cons of these

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[6] See EB-2018-0165, Decision and Order, December 19, 2019. While approving Toronto Hydro's Custom IR plan for 2020-2024, the OEB stated:

> The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework. (p. 24)

options, we recommend an extra stretch factor term for setting the C-factor. The OEB first approved this kind of provision in its recent Hydro One Distribution decision.[7]

We endorse the Company's proposal to be able to keep a small percentage of accumulated capex underspends because this provision strengthens capex containment incentives. We recommend that the Hydro One's share of the value of underspends be 5%, and not 2% as the Company proposes. Hydro One should also be permitted to keep a share of its demonstrated productivity savings.

[7] EB-2017-0049. Decision and Order issued March 7, 2019.

2. Hydro One's Custom IR Proposal

Hydro One has in this proceeding proposed CIR frameworks for its power transmission and distributor services. Multiyear rate plans would set rates for the five-year period from 2023 to 2027. The revenue requirements for 2023 would be established by conventional rebasings that use forward test years. Allowed revenue for the remaining years of the plan would then be escalated using an RCI with a formula that features an Inflation Factor ("I"), Productivity Factor ("X"), Custom Capital Factor ("C"), and Z factor.

$$Growth\ RCI = I - X + C +/- Z.$$

The Company proposes industry-specific inflation measures like those used in its previous CIR plans. For each group of services, the growth rate of the inflation measure would be a weighted average of the growth in two Statistics Canada inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the Average Weekly Earnings for Workers in Ontario ("$AWE^{Ontario}$"). The respective weights on these two indexes would be based on the average shares of labor and other inputs as approved by the OEB in previous decisions. The weights for transmission were approved in the OEB's decisions approving IR plans for Hydro One Sault Ste. Marie and the current CIR plan for HON, based on the total applicable transmission costs of the utilities in the econometric samples in those proceedings.[8] The weights for distribution were approved by the OEB in its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors."[9] The inflation measure would be updated annually.

Each proposed X factor would be fixed during the plan as the sum of a base productivity growth factor and a stretch factor. 0% base productivity growth factors are proposed, which is consistent with

[8] EB-2018-0218 and EB-2019-0082.

[9] EB-2010-0379.

the OEB's 4th generation IRM decision.[10] The proposed stretch factors are supported by Clearspring's total cost benchmarking report.

The proposed C Factor in each RCI is the percentage change in the total revenue requirement which is needed to eliminate any positive difference between the growth in the Company's approved capital revenue requirement and the growth in its capital revenue that is otherwise produced by the RCI. The capital revenue requirement thus defined would include depreciation, return on rate base, and taxes. Hydro One's forecasted/proposed transmission and distributor capital costs are supported by system plans. Supplemental stretch factors of 0.15% would slow the growth in the capital revenue requirement. Its C factor for distribution would average 2.85%, while its C factor for transmission would average 3.04%. HON proposes to update the C Factors each year for inflation.

Several of the Company's costs would be addressed by variance accounts. These would include the costs of pensions and other post-employment benefits and of the development of some new projects and externally-driven projects (e.g., those required by governmental authorities) for transmission. Variance accounts for distribution include the costs of pensions and other post-employment benefits, externally-driven distribution projects (e.g., 3rd-party initiated, distributed energy resource connections, or service upgrades), and AMI 2.0 deployment for distribution. Subsequent to the filing of its Custom IR proposal, Hydro One received approval of a separate variance account for the costs of transmission projects that it is ordered to undertake by the IESO, Order in Council, or direction of the Minister of Energy and that are expected to be owned and included in the rate base of any new partnership affiliated with Hydro One Transmission.[11]

An asymmetrical capital in service variance account ("CISVA") would track the cumulative impact on the revenue requirement of variances between the actual and approved value of in-service plant additions. 98% of any cumulative shortfalls would be disposed of to the benefit of customers at

[10] OEB, EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

[11] Examples of projects that would be addressed by this variance account are new transmission lines: the Waasigan Transmission Line, the Chatham to Lakeshore Transmission Line, and the Lambton to Chatham Transmission Line.

the end of the Custom IR term. Hydro One would keep the value of the first 2% of underspends. The Company could also keep shortfalls resulting from verifiable productivity gains.

The company could request Z factor treatment if qualifying events occurred, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $3 million or more. Events that could trigger a Z factor claim include severe storms and investments that are government-mandated or outside of management's control for other reasons. Z-factor claims in Ontario may address OM&A and/or capital costs of qualifying events. While there is a materiality threshold, that threshold is not used as a dead zone.

Asymmetrical T&D earnings-sharing mechanisms ("ESMs") would share 50% of earnings which exceed the target rate of return on equity ("ROE") by more than 100 basis points in any year. Hydro One has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if the Company actual achieved ROE on a regulated basis varied from the OEB-approved ROE by more than 300 basis points (i.e., ± 300 b.p.) in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without change, or the termination of the plan.

3. Critique of Clearspring's Power Transmission Research

Mr. Fenrick has changed his transmission productivity and benchmarking research methods in the following areas where we were critical of his work as filed and tested in past OEB proceedings.[12] This eliminates some areas of controversy. Here are some notable examples.

- The initial or benchmark year used for the calculation of capital costs and quantities is 1948 now instead of 1988.
- The featured sample period for the U.S. transmission productivity research has 19 (growth rate) years, not 13 years.
- Capital asset prices are levelized using data from multiple cities in the service territory of each utility.
- Construction cost trends in Ontario were computed as a weighted average of the trends in two asset price indexes.
- The OM&A input price indexes now have company-specific weights.
- Pensions and benefits were excluded from the data for Hydro One and all of the U.S. utilities.

3.1 U.S. Transmission Productivity

Clearspring Study

Clearspring calculated the transmission productivity trends of 50 U.S. electric utilities over the nineteen-year 2001-2019 period. A **-1.66**% average annual multifactor productivity growth trend was reported for the sampled transmitters over this period. Growth in OM&A productivity averaged -2.30% while capital productivity growth averaged -1.50%.

Output growth was calculated using a multidimensional index with two scale variables: line length and a 10-year rolling average of maximum peak demand. The weights for these variables were

[12] See for example EB-2017-0049 (Hydro One Dx), EB-2018-0082 (Hydro One Tx), EB-2018-0218 (Toronto Hydro) and EB-2019-0165 (Hydro Ottawa).

based on estimates of their cost elasticities. These estimates were obtained from an econometric model of total power transmission cost which Clearspring developed with data from 50 U.S. utilities for the nineteen-year 2001-2019 period. The weight for line length was 36.6% in the scale index whereas the weight for peak demand was 63.4%.

Capital cost was measured using a variant of the geometric decay method in which capital gains were not considered. The benchmark year in the capital cost computation was 2002 for Hydro One.

PEG Critique

Our examination of Clearspring's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we first highlight our chief concerns with Clearspring's methods. There follows brief discussion of some of our other concerns. Geometric decay and other monetary methods for calculating capital costs, prices, and quantities are discussed in Appendix Section A.2.

Chief Concerns

Sample Period Even though Clearspring lengthened the sample period for its productivity study from thirteen years to nineteen years, the resultant productivity trend may still not be appropriate for the determination of Hydro One's X factor. The transmission capex of sampled utilities was boosted during these years by the need to improve the functioning of bulk power markets and to access remote renewable resources whose development was stimulated by federal tax policy and state renewable portfolio standards. The FERC increased its oversight over transmission reliability, causing many transmitters to incur Critical Infrastructure Protection ("CIP") costs. In addition to the fact that the slowdown in productivity growth due to CIP standards may be temporary, Hydro One may seek to Z factor qualifying material new CIP costs driven by external agencies which the Company incurs during the proposed plan term.

Changes in U.S. regulation weakened transmission cost containment incentives. The FERC has offered ROE premia for some kinds of transmission capex, and a large and growing number of the sampled transmitters operated under formula rate plans administered by the FERC. These plans are essentially comprehensive cost trackers.

The reasons for negative MFP growth in the U.S. during its chosen sample period may thus be very different from the challenges that the Company faces. In this regard, it is notable that Clearspring makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One during the term of the proposed plan. In response to OEB staff interrogatory 339-b in this proceeding, Clearspring stated that

> The challenges that have arisen in the transmission industry have reduced the MFP trend of the sector substantially. These challenges remain present or are growing larger throughout the CIR period. We cannot comment on the relative importance of the drivers and have not conducted a study to disentangle their impacts.

The nineteen-year sample period used by Clearspring is considerably shorter than those featured by both expert witnesses in a recent proceeding by the Régie de l'énergie to reconsider the revenue cap index in the multiyear rate plan of Hydro-Québec Transmission. The Brattle Group represented Hydro-Québec in that proceeding and based its 1.04% X factor recommendation on the transmission MFP trend that it calculated over the 25-year 1995 to 2019 sample period.[13] Dr. Agustin Ros led the Brattle research team and stated on the witness stand in the proceeding that

> I recommend the use of a long-term trend because I'm interested in the long-term X-Factor. It's the long-term that provides the incentive properties of zero economic profits. So I like to use a long-term estimate of what total factor productivity is.[14]

PEG represented a group of industrial intervenors in this Québec proceeding. The 0.62% base productivity trend that we recommended was the MFP trend of sampled U.S. transmitters calculated over the 24-year 1996 to 2019 sample period.

Structural Change Clearspring's treatment of opex does not handle structural change in the U.S. transmission industry well. As discussed further in Appendix C, many U.S. electric utilities joined independent system operators ("ISOs") or regional transmission organizations in the last twenty years. ISO members began purchasing a wide range of transmission services from these agencies and some

[13]Ros, Agustin, Graf, W., Shetty, S., Castaner, M., "Total Factor Productivity and the X-factor for Hydro-Québec TransÉnergie," filed in Règie de l'ènergie proceeding R-4167-2021, as Exhibit B-0012, HQT-5, Document 2, February 19, 2021.

[14] Régie de l'énergie R-4167-2021, Exhibit A-0044,Transcript for 13 decembre 2021, pp.51-52.

members reported these costs idiosyncratically. We believe that this materially affected the reported costs of some companies in ways that are not pertinent to the X factor of Hydro One Transmission.

Capital Cost Specification Capital cost data for Hydro One are available only since 2002.[15] While this situation can't be helped, it can materially reduce the accuracy of capital cost and quantity estimates, as we discuss further in Appendix Section A.2.

3.2 Transmission Cost Benchmarking

Clearspring Research

Clearspring used its econometric transmission cost model to benchmark the total transmission cost of Hydro One. The Company's total cost was substantially below the featured Clearspring benchmarks throughout the sample period but the benchmark scores tended to worsen (i.e., trended towards the benchmark) over time. The Company's cost was nearly 70% below the benchmark in 2008 but its forecasted/proposed total cost is about 35% below the benchmarks on average during the five years of the proposed plan (2023-2027). From 2023 to 2027, the Company's total transmission cost efficiency would average a 1.12% annual decline.

PEG Critique

Our review of Clearspring's transmission benchmarking research raised several concerns. We group these with respect to their importance.

<u>Biggest Concerns</u>

Here are our biggest concerns.

- The econometric sample included data from several companies that reported implausibly large values for dispatch-related and/or miscellaneous transmission expenses. All of these companies were ISO members.

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

- Data have been reported on FERC Form 1 for transmission peak demand since 2004. A longer time series is available on the form for monthly peak demand. This is a notion of peak demand that conforms to a utility's native load and requirement sales for resale.[16]

  Clearspring based its peak demand variable on the monthly peak demand data when transmission peak demand is more appropriate. We acknowledge that Clearspring needed to use monthly peak demand for its productivity trend research because the transmission peak load data did not start until 2004 and Clearspring sought an earlier start date. However, there was no need to use the same peak demand variable in the benchmarking research, or to have a sample period for the econometric benchmarking research which was the same as that for the productivity trend research.

- We believe that it is more appropriate to ratchet monthly peak demand than it is to take a rolling average. The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand for grid services.

- In PEG's view, Clearspring's transmission substation data are inaccurate. This is discussed at some length in Appendix Section B.2.

- Clearspring did not include the construction standards index as a cost driver. Mr. Fenrick used this variable in his prior transmission cost benchmark study for Hydro One.

- As a scope economy variable Clearspring used the ratio of transmission gross plant value to total gross plant value. A more appropriate variable is the ratio of transmission gross plant value to total gross plant value less the value of general plant. We are also concerned that scope economy variables based on plant value shares have a large parameter estimate that

[16] An idiosyncrasy of these alternative demand data is that they do not include non-requirements sales for resale. The requirement sales for resale that are included are contractually firm enough that the party receiving the power is able to count on it for system capacity resource planning. Non-requirements sales for resale do not meet this standard and include economy energy. The load associated with non-requirements sales for resale can be shed in times of capacity constraints.

may reflect a correlation between the value of transmission plant and transmission capital cost.

- Clearspring includes an ISO binary variable in its model that assumes a value of 1 if the utility was an ISO member and 0 if it wasn't. The parameter estimate for this variable is unfortunately bolstered by the inappropriate inclusion in the Clearspring sample of data for some ISO members that seem to have idiosyncratically reported their OM&A expenses. We are also concerned that the parameter estimate for this variable may be bolstered by a tendency of ISO members to face cost pressures, not elsewhere properly captured in Clearspring's model, which are unrelated to ISO membership. For example, ISO members are more likely to serve areas with high input prices and urban congestion.

Other Concerns

Here are some less important but nonetheless notable concerns that we have with Clearspring's transmission cost performance research for this proceeding.

- Only Handy Whitman indexes for *transmission* plant were used to calculate capital price and quantity trends even though a modest portion of the assets in the calculations are *general* plant.

4. Alternative Transmission Research by PEG

Our concerns about Clearspring's transmission research have prompted us to produce results using alternative and more defensible methods. In this research, we relied chiefly on Clearspring data but used these data in different ways.

4.1. Benchmarking

Dependent Variable

As in the Clearspring study, the dependent variable in each cost model we developed was *real* cost: the ratio of (nominal) cost to an input price index. This specification enforces a key result of cost theory.[17] Even though input prices are not listed as a business condition variable, our benchmarks therefore reflect the input prices in Hydro One's transmission service territory.

Output Variables

Two output (aka scale) variables were used in our econometric cost model: length of transmission line and ratcheted maximum peak demand. We used Clearspring's line length data, which were drawn from Transmission Line Statistics on page 422 of FERC Form 1. We constructed a ratcheted peak demand variable using the transmission peak demand data Mr. Fenrick relied on in his prior work for Hydro One Transmission.[18]

We followed Clearspring's practice of according the two scale variables in our model a "translog" treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. No second-order terms were included in this model for the other business condition variables. Functional form issues are discussed further in Appendix Section B.1.

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

[18] See EB-2018-0218, Exhibit D-1-1, Attachment 1, Fenrick, Steve and Sonju, Erik, Power System Engineering, Inc., "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," May 23, 2018, and EB-2019-0082, Fenrick, Steve and Sonju, Erik, Power System Engineering, Inc., "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," January 24, 2019.

Other Business Condition Variables

Seven other business condition variables were used in our transmission cost modelling. Four of these variables address characteristics of the transmission system. These are the average voltage of transmission lines, substation capacity per substation, the number of substations per transmission line kilometer, and the share of transmission assets that are overhead.[19] We expect the parameters of the first three variables to have positive signs, while that for the third should have a negative sign in a transmission total cost or capital cost model.

The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

To measure scope economies we calculated the share of transmission in the gross value of total plant less the value of general plant. The model also includes a forestation variable and the construction standards index for transmission tower construction which Mr. Fenrick developed and used in his prior study for Hydro One Transmission. We expect both of these variables to have positive parameter estimates.

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

[19] The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

4.2 Econometric Results

Details of our three featured econometric cost models are found in Tables 1-3. Each table reports estimates of business condition parameters and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development. In all three models, the parameters of the business condition variables are statistically significant at a high level of confidence and have sensible signs and parameter values.[20]

Total Cost

Results for our featured total cost model are reported in Table 1. Our research indicates that transmission costs tended to be higher to the extent that sampled utilities had higher peak demand and line length. The parameter estimates for the quadratic and interaction terms for the scale variables were insignificant.

Total transmission cost was also higher to the extent that utilities had

- higher average line voltage;
- more substation capacity per substation;
- more substations per transmission line km;
- more transmission facilities underground;
- higher required construction standards;
- more forestation; and
- transmission plant that constituted a larger share of the gross value of total plant less general plant.

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

Table 1

PEG's Featured Econometric Model of Transmission Total Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
VOLT =	Average Voltage of Transmission Lines
PCTOH =	Percentage Overhead Distribution Plant
CS =	Construction Standards Index
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.355	26.390	0.000
D	0.581	35.020	0.000
YL*YL	0.024	1.930	0.073
D*D	0.113	5.610	0.000
D*YL	-0.059	-3.000	0.009
PCTPTX	0.387	8.300	0.000
MVA	0.099	4.420	0.000
SUBKM	0.101	3.690	0.002
VOLT	0.180	7.450	0.000
PCTOH	-1.153	-5.350	0.000
CS	0.145	4.810	0.000
FOR	0.092	7.670	0.000
Trend	0.014	7.370	0.000
Constant	12.063	348.140	0.000

Adjusted R^2	0.944
Sample Period	2004-2019
Number of Observations	803

The parameter estimates for the scale variables suggest that ratcheted peak demand had an estimated long-run cost elasticity of 0.581% whereas the estimated cost elasticity of transmission line length was 0.355%. The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by about 1.34% annually for reasons that aren't explained by the business condition variables in the model. The adjusted R-squared for the model is 0.944.

Please also note the following.

- If the two substation variables in our model are replaced with the corresponding two Clearspring substation variables, the parameter estimates on the replacement variables have substantially lower statistical significance.

Capital Cost

Econometric results for PEG's capital cost model are presented in Table 2. Here are some key findings.

- The parameter estimates for the number of transmission line kilometers and ratcheted peak demand were highly significant and positive. Two of the three second-order scale variables had significant estimates.
- Capital cost was also higher the greater was average line voltage, MVA per substation, the number of substations per kilometer of transmission line, required construction standards, the extent of service territory forestation, and the share of transmission in total gross plant value less the value of general plant.
- Capital cost was lower the greater was the share of transmission lines that were overhead.

Table 2

PEG's Featured Econometric Model of Transmission Capital Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTPOH=	Percentage Overhead Lines
CS =	Construction Standards Index
VOLT =	Average Voltage of Transmission Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.313	37.020	0.000
D	0.657	46.450	0.000
YL*YL	-0.069	-3.670	0.002
D*D	0.108	3.570	0.003
D*YL	-0.005	-0.160	0.873
PCTPTX	0.435	7.400	0.000
MVA	0.079	2.630	0.019
SUBKM	0.083	3.300	0.005
VOLT	0.204	15.160	0.000
PCTOH	-1.084	-5.100	0.000
CS	0.142	4.710	0.000
FOR	0.074	7.490	0.000
Trend	0.012	4.460	0.000
Constant	9.867	266.280	0.000

Adjusted R^2	0.942
Sample Period	2004-2019
Number of Observations	803

- The estimate of the trend variable parameter indicates a 1.2% annual increase in capital cost for reasons other than changes in the values of the model's business condition variables.

- The 0.942 value of the adjusted R^2 for the capital cost model was similar to that of the total cost model.

OM&A Expenses

Results for PEG's transmission opex model are presented in Table 3. Please note the following.

- The parameter estimates for the number of transmission line kilometers and ratcheted peak demand were highly significant and positive. The estimates for the three quadratic and interaction terms associated with the scale variables were also highly significant. This suggests that the relationship of cost to the two scale variables was significantly nonlinear.

- Opex was higher the greater was the share of transmission plant in the gross value of total plant less general plant.

- Opex was also higher the higher was MVA per substation, the number of substations per kilometer of transmission line, and the share of the service territory that was forested.

- Opex was lower the greater was the share of transmission lines that were overhead.

- The trend variable parameter estimate indicates a 2.1% annual increase in opex for reasons other than changes in the values of included business condition variables. This increase is slightly more rapid than that in the total cost model.

- Table 3 also reports a 0.784 adjusted R^2 statistic for the opex model. This is well below that for the total cost and capital cost models.

Table 3

PEG's Featured Econometric Model of Transmission OM&A Expenses

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTPOH=	Percentage Overhead Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.438	10.310	0.000
D	0.326	14.560	0.000
YL*YL	0.383	14.440	0.000
D*D	0.126	5.530	0.000
D*YL	-0.303	-17.230	0.000
PCTPTX	0.177	7.570	0.000
MVA	0.131	7.260	0.000
SUBKM	0.107	2.940	0.010
PCTOH	-1.193	-3.900	0.001
FOR	0.188	5.510	0.000
Trend	0.021	5.440	0.000
Constant	10.111	172.570	0.000

Adjusted R^2	0.784
Sample Period	2004-2019
Number of Observations	802

Pacific Economics Group Research, LLC

4.3 Business Conditions Facing Hydro One Transmission

Before discussing the benchmarking results for Hydro One Transmission using these models we consider the external business conditions that the Company faces. Hydro One provides virtually all power transmission services in the sprawling province of Ontario. The population of Ontario is by far the largest in Canada and exceeds that of Wisconsin, Minnesota, and the two Dakotas combined. Most power production and consumption in the province occurs in the southern lowlands that border the Great Lakes and the two largest rivers. However, Hydro One Transmission also serves a large region on the Canadian shield which is dotted by hydroelectric generating sites and resort, forestry, and mining communities. In this region forests are thick, igneous rock is near the surface, and winter weather is severe.

Table 4 compares the cost and external business conditions of Hydro One Transmission to the sample mean values in 2019. Consider first results for the important cost, price, and scale variables.

- Hydro One's total cost was 7.34 times the sample mean while its input prices were 1.15 times the mean. The Company's real total cost was 6.46 times the mean.
- Hydro One's ratcheted transmission peak was 3.36 times the mean while its line miles were 3.72 times the mean (and second highest in the sample).
- Combining all of these metrics, the Company's bilateral multifactor productivity level was 0.54 times the sample mean in 2019. Its O&M productivity level was 0.65 times the mean while its capital productivity level was 0.53 times the mean. These simple benchmarking metrics are not favorable to the Company.

Here are comparisons for some of the additional business conditions that Hydro One faced.

- The number of substations served was 4.65 times the mean.
- The MVA per substation was 1.18 times the mean.
- The average voltage of transmission lines was 1.27 times the mean.
- The share of transmission in the gross value of Hydro One's total plant less general plant was 2.88 times the mean and the highest in the sample.

Table 4

How the Model Variables for HON Tx Compare to the Sample Mean (2019)

	HON	Sample Mean	HON / Mean	HON Rank
Cost				
Total Cost	$ 2,036,426	$ 277,392	7.34	1
OM&A Cost	$ 304,934	$ 43,291	7.04	1
Capital Cost	$ 1,731,492	$ 234,101	7.40	1
Input Prices				
Input Price Index	1.458	1.265	1.15	4
OM&A	1.318	1.000	1.32	
Capital Price	10.82	9.64	1.12	7
Labor Price	89,695.97	65,602.52	1.37	1
M&S Price	139.40	112.35	1.24	1
Real Cost (Cost / Price Index)				
Total Cost	1,396,477	216,049	6.46	
OM&A Cost	231,407	43,291	5.35	
Capital Cost	160,090	24,285	6.59	
Scale				
Substations	264	57	4.65	1
Mva	109,320	17,576	6.22	1
Mva / Station	414	350	1.18	15
km of Line	20,783	5,580	3.72	2
Monthly Peak Load	21,791	5,005	4.35	2
Ratcheted 10 Year Monthly Peak	23,541	5,034	4.68	1
Ratcheted Transmission Peak	23,541	7,006	3.36	4
Scale Index				
Lines	3.72	1.00	3.72	
Peak	3.36	1.00	3.36	
Weight on Lines	38%	38%		
Weight on Peak	62%	62%		
Scale Index	3.49	1.00	3.49	
Bilateral Productivity Level				
Multifactor	0.541	1.00	0.54	
OM&A	0.654	1.00	0.65	
Capital	0.530	1.00	0.53	
Other Business Conditions				
Share of Transmission Plant in Total Gross Plant Value less General Plant	61.3%	21.3%	2.88	1
MVA per Station	414.1	350.1	1.18	15
Substations per km of Transmission Line	0.0127	0.0129	0.99	17
Percent Overhead	98.6%	97.3%	1.01	41
Construction Standards Index	0.867	0.674	1.29	4
Average Voltage of Lines	222	174	1.27	12
Percent Forestation	74.4%	55.6%	1.34	17

- The extent of forestation in the service territory was 1.34 times the mean.
- The Company is a member of an ISO whereas a number of the sampled US utilities are not.
- The value of the construction standards index was 1.29 times the mean and one of the highest in the sample.
- The percent of plant underground was similar to the mean.

In summary, the productivity level calculations raise concern that Hydro One Transmission may be a poor cost performer. However, the business conditions that it faces do seem to be unusually challenging on balance. We turn to the econometric model to see how these considerations balance out.

4.4 Transmission Cost Benchmarking Results

We used our three econometric transmission cost models to benchmark the corresponding costs of Hydro One. In this exercise we used Clearspring's forecasts for growth in input prices. Due to the unavailability of older capital cost data for Hydro One, results of the total cost and capital cost benchmarking will tend to be more accurate in the later years considered.

Total Cost

Results of our transmission total cost benchmarking work are presented in Table 5 and Figure 1. It can be seen that Hydro One's total cost performance has been trending downward since 2008. Its cost was about 7% above our benchmarks on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. The downward trend seems to have been arrested during the current CIR. The Company's forecasted/proposed total costs are about 14% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). Between 2023 and 2027, total cost efficiency is expected to average a 1.12% average annual decline.

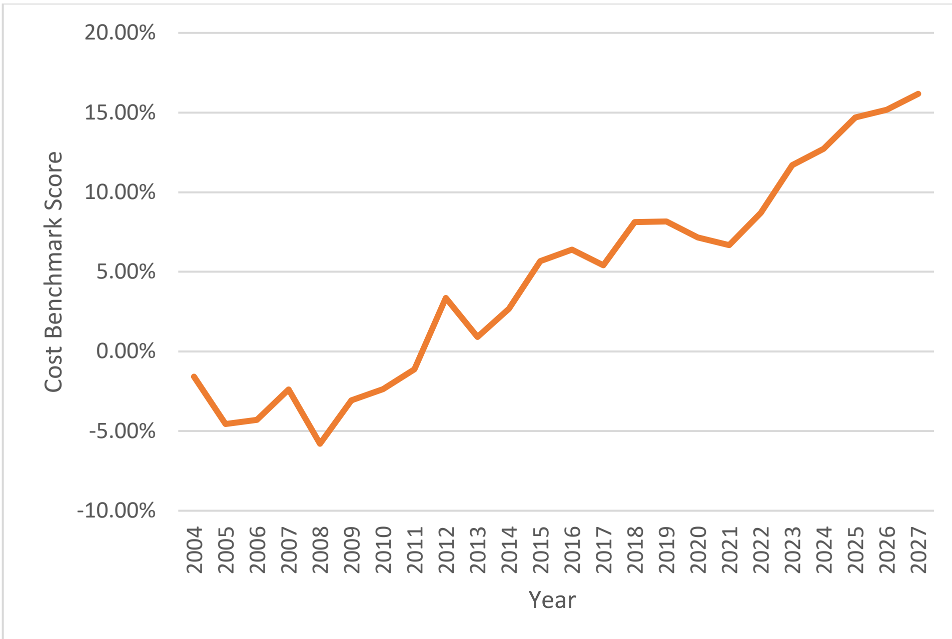
Table 5
Transmission Total Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-1.58%
2005	-4.56%
2006	-4.30%
2007	-2.39%
2008	-5.80%
2009	-3.07%
2010	-2.37%
2011	-1.11%
2012	3.35%
2013	0.92%
2014	2.68%
2015	5.67%
2016	6.38%
2017	5.41%
2018	8.12%
2019	8.16%
2020	7.16%
2021	6.67%
2022	8.71%
2023	11.70%
2024	12.71%
2025	14.69%
2026	15.17%
2027	16.18%
Average 2017-2019	**7.23%**
Average 2023-2027	**14.09%**

Figure 1

Hydro One's Total Transmission Cost Benchmarking Scores Using PEG's Alternative Econometric Model



Capital Cost

Results of our transmission capital cost benchmarking work are presented in Table 6 and Figure 2. It can be seen that the Hydro One's capital cost performance began a steady decline after 2008. Its cost was about 6% above the model's prediction on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. The Company's forecasted/proposed total costs are about 19% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). From 2023 to 2027, capital cost efficiency is expected to average a 1.66% annual decline.

Table 6

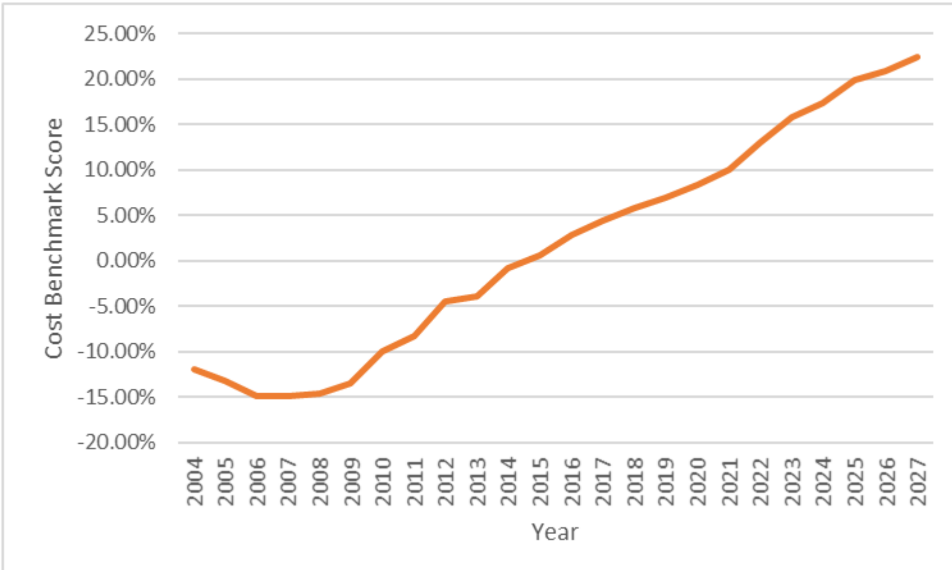
Transmission Capital Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-11.90%
2005	-13.26%
2006	-14.88%
2007	-14.84%
2008	-14.63%
2009	-13.43%
2010	-10.02%
2011	-8.32%
2012	-4.53%
2013	-3.87%
2014	-0.85%
2015	0.60%
2016	2.82%
2017	4.39%
2018	5.86%
2019	6.88%
2020	8.29%
2021	9.99%
2022	12.98%
2023	15.75%
2024	17.31%
2025	19.95%
2026	20.91%
2027	22.41%
Average 2017-2019	**5.71%**
Average 2023-2027	**19.27%**

Figure 2

Hydro One's Transmission Capital Cost Benchmarking Scores Using PEG's Alternative Econometric Model



OM&A Expenses

Results of our transmission O&M cost benchmarking work are presented in Table 7 and Figure 3. It can be seen that Hydro One's opex performance has tended to improve since 2007. The Company's opex was about 36% above the model's prediction on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. Opex efficiency should improve markedly during the current CIR. This favorable trend is interrupted by a setback in 2023, the forward test year. The Company's forecasted/proposed total costs are about 7% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). From 2023 to 2027, opex efficiency would improve at a 2.15% average annual pace.

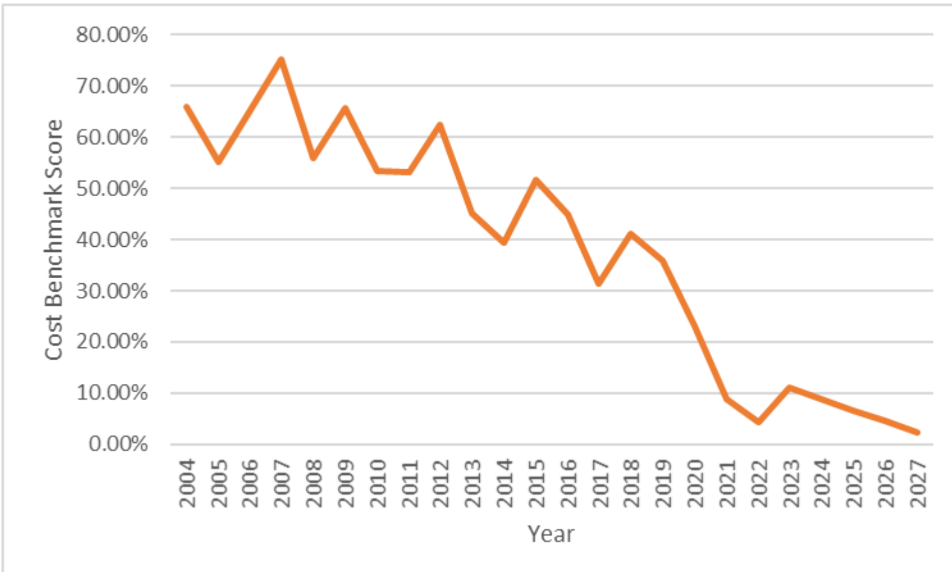
Table 7

Transmission OM&A Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	66.01%
2005	55.18%
2006	64.84%
2007	75.08%
2008	55.89%
2009	65.57%
2010	53.44%
2011	53.27%
2012	62.54%
2013	45.12%
2014	39.51%
2015	51.55%
2016	44.90%
2017	31.44%
2018	41.11%
2019	35.80%
2020	23.07%
2021	8.93%
2022	4.43%
2023	10.98%
2024	8.87%
2025	6.67%
2026	4.54%
2027	2.36%
Average 2017-2019	**36.12%**
Average 2023-2027	**6.68%**

Figure 3
Hydro One's Transmission OM&A Cost Benchmarking Scores Using PEG's Alternative Econometric Model



4.5 Productivity Research

The calculation of transmission industry productivity trends was not part of PEG's scope of work in this proceeding. However, we recently undertook research and testimony on this matter in a Québec proceeding.[21] Our clients there were the Association Québécoise des Consommateurs Industriels d'Électricité and the Conseil de l'Industrie Forestière du Québec.

Our productivity research methodology was broadly similar to that of Clearspring in this proceeding. Notable differences included the following.

- Companies with implausible transmission-dispatch-related and miscellaneous transmission expenses were excluded.

[21] Lowry, 2021 op. cit.

- There were differences in the sampled companies.
- A longer sample period was considered.

Results of this research can be found in Table 8 below. For the full sample period, it can be seen that the multifactor productivity growth of sampled U.S. transmitters averaged -0.62% per annum while OM&A productivity growth averaged -0.68% per annum.

Table 8

PEG's Transmission Productivity Results from the Hydro-Québec Proceeding

Sample Period	Average Annual Productivity Growth Rate		
	OM&A	Transmission Capital	Multifactor
1996-2019 (24 years)	-0.68%	-0.46%	-0.62%
2005-2019 (15 years)	-1.74%	-2.16%	-2.26%

4.6 Transmission X Factor Recommendations

Base Productivity Trend

We believe that the **-0.62**% trend in the MFP of the U.S. power transmission industry which we calculated for our full 1996-2019 sample period in the Québec proceeding is a reasonable base productivity trend for Hydro One.

Stretch Factor

We disagree with Clearspring's 0.0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted given Hydro One's superior cost performance. We discuss the general considerations that go into the choice of a stretch factor in Appendix Section A1. Based on this general discussion, we provide here some considerations that we feel are pertinent for choosing a transmission stretch factor for Hydro One.

- The Company's cost performance does not score as well in our study as in Clearspring's study. We found that the Company's forecasted/proposed total cost during the five years of the proposed plan would be 14% above our model's prediction on average. In 4GIRM this kind of cost benchmarking score is commensurate with a 0.45% stretch factor.

- Stretch factors should reflect the difference between the incentive power of the proposed plan and the incentive power of the regulatory systems of companies in the productivity studies used to establish the base productivity trend. The incentive power of U.S. transmission regulation was unusually weak during the ample period of the productivity study due to the FERC's use of ROE premia and formula rate plans. This problem loomed larger during Clearspring's shorter and more recent sample period.
- The RCI formula does not include a scale escalator to help fund output growth. On the other hand, growth in the Company's output has been slow in recent years and this is expected to continue. The plan includes variance accounts for costs of major line extensions, and supplemental revenue for growth-related capex may also be obtained via the C factor.
- Stretch factors linked to cost performance have the additional benefit of serving as efficiency carryover mechanisms that reward utilities for long-term cost savings and penalize them for their absence.

Balancing these considerations, we believe that a 0.75% stretch factor is reasonable for Hydro One. This would include a 0.45% "normal" stretch factor based on the total cost benchmarking work and a 0.30% adder for the unusually weak performance incentives of sampled US utilities.

X Factor

A -0.62% base productivity trend and a 0.75% stretch factor would produce a 0.13% X factor. This is the X factor we recommend for Hydro One's transmission services.

5. Critique of Clearspring's Power Distribution Research

5.1 Summary of Clearspring's Work

Clearspring benchmarked the total cost of Hydro One's distributor base rate inputs over the 16-year historical period from 2005 to 2019. The Company's projected/proposed costs were benchmarked for the 2020-27 period that includes the five years of the new rate plan (2023-2027). Clearspring did not separately benchmark Hydro One's component opex and capital costs or its reliability.

An econometric model provided the cost benchmarks. Clearspring developed this model using data on power distributor operations of 81 investor-owned utilities in the United States. The sample period was the twenty years from 2000 to 2019.

The dependent variable in the model was real cost. Differences in the wage levels and construction costs that utilities in the sample faced were considered in the construction of the input price indexes. The model has three scale variables: the number of customers served, the area of the service territory area, and a moving average of maximum monthly peak demand.

The model also contained the following variables that measure other drivers of distributor cost.

- share of the service territory area that has urban congestion;
- share of customers with advanced metering infrastructure ("AMI");
- share of electric customers in the sum of gas and electric customers served;
- % of distribution plant overhead x share of service territory forested; and
- % of transmission lines with ratings above 50kV.

The model also contains a (linear) trend variable.

With respect to the form of Clearspring's distribution cost model, the model contains a full complement of quadratic and interaction terms (e.g., Customers x Customers, Customers x Area, and Customers x Peak Demand) for the three scale variables in addition to the corresponding first-order terms (Customers, Area, and Ratcheted Peak Demand). All parameter estimates for the variables in the model are highly significant and those for the first order terms have plausible signs. The estimate of the trend variable parameter suggests that cost was *falling* by about 0.4% annually over the sample period for reasons other than changes in the values of the included business condition variables.

Clearspring reported that Hydro One's total distribution costs were well below the benchmarks yielded by its model in the early years considered (e.g., 2005 to 2010). However, the Company's cost performance tended to erode. Cost performance is expected to improve modestly from 2019 to 2022. However, deterioration is forecasted to resume in the new plan. The Company's forecasted/proposed costs over the five years of the proposed new plan exceed the corresponding benchmarks by 7% on average. From 2023 to 2027, Clearspring reports that Hydro One's distribution total cost efficiency will average a 1.75% annual decline.

5.2 Critique

Mr. Fenrick has changed his power distribution benchmarking methodology in several areas where we were critical of his approach in past Ontario proceedings. As in his transmission research,

- The initial or benchmark year for the calculation of capital costs and quantities is 1948, not 1988.
- The construction cost was levelized in the correct year.
- Construction cost trends in Ontario were computed as a weighted average of the trends in two asset price indexes.
- The OM&A input price indexes now have company-specific weights.
- Pensions and benefits were excluded from the data for Hydro One and all of the U.S. utilities.

Additionally,

- Quadratic and interaction terms for other business conditions have been reduced.
- Attention to urban and rural cost challenges is more balanced.

We nonetheless disagree with some of the methods Clearspring used in this study. Our concerns range from major concerns to concerns that are small but nonetheless notable. We discuss our larger concerns first to facilitate the Panel's review.

Major Concerns

Density Issues

Clearspring has in past proceedings developed a service territory area variable that is potentially useful in benchmarking costs of power distributors. Unfortunately, it is problematic to use this variable when benchmarking Hydro One due to uncertainty about the appropriate value for the Company. In his previous work for Hydro One Distribution Mr. Fenrick used as his estimate the total area of Ontario, including water bodies. In the new study he used the value that PEG used for Hydro One in the last Custom IR proceeding for Hydro Ottawa. This is the area of Ontario's land surface less the estimated service territory areas of other utilities. However, even this estimate includes an enormous area in the north of the province that does not have distribution service.

Distribution Work

We agree that a variable measuring the extent of distribution subtransmission lines is worthwhile. However, we don't' think that the variable Clearspring used for this purpose (% of transmission lines with ratings above 50kV) is appropriate.

Other Major Concerns Here are some other major concerns that we have with Clearspring's benchmarking work in this proceeding.

- The denominator of the scope economy variable should not include general plant.
- Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in more granular management of major cost categories such as OM&A expenses is useful to utilities and regulators alike.

Smaller Concerns

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

- Data are frequently mean-scaled in econometric cost studies. This ensures that elasticities are calculated at sample mean values of the business condition variables. Clearspring mean-scaled the data for some variables, but not for others.[22]

- Clearspring benchmarked the reliability of Hydro Ottawa in its recent evidence for that company. They gathered a respectable sample of publicly available U.S. data that span the years 2010-2017. Major event days were excluded, if not with fully consistent definitions. The models presented by Clearspring are a good starting point for further improvements. Cost benchmarking should ideally be combined with reliability benchmarking to gain a balanced view of performance, and reliability performance is germane when considering requests for supplemental capex funding. Reliability results for Hydro One would have been informative.

5.3 Business Conditions Facing Hydro One Distribution

The external cost drivers faced by Hydro One Distribution should be considered when benchmarking their cost. The Company is headquartered in Toronto, a high-cost urban area, but provides distributor service to numerous small towns and rural areas of the province. Its service territory includes numerous forest products and resort communities on the Canadian shield. As is the case for Hydro One Transmission, dense forests and severe winter weather are the norm in this region. However, due in part to the growth of metropolitan areas and to acquisitions by Hydro One, the Company does serve some larger towns and suburban areas. All customers now have AMI.

Table 9 compares Hydro One's cost and external business conditions to the sample mean values in 2019. The following results are notable.

- Hydro One's total cost was 2.07 times the sample mean.

- The input prices that the Company faced were 1.17 times the mean. Thus, the Company's real total cost was 2.19/1.16 = 1.78 times the mean. The Company's customer count was 1.30 times the mean while its ratcheted peak demand was 1.14 times the mean. The

[22] HON Technical Conference, Transcript December 16, 2021, p. 26-27.

reported area served was a fantastical 31 times the mean. However, the Company's transmission line length was a more plausible 3.89 times the mean. A scale index computed using transmission line miles had a value 1.35 times the mean.

- Combining all of this information, Hydro One's multifactor distributor productivity level in 2019 was 0.77 times the mean. Its O&M productivity was 0.83 times the mean while its capital productivity was 0.73 times the mean.

These benchmarking metrics are unfavorable to the Company. For Hydro One to be deemed a good distribution cost manager, it would therefore have to face other cost drivers that are markedly less favorable than the sample norms on balance. The table indicates that several business conditions were more challenging.

- Forestation in the Company's service territory was 1.30 times the mean.
- The share of customers with AMI was about twice the mean.
- The share of electric customers in the sum of gas and electric customers was 1.13 times the mean. The Company does not provide gas services.

On the other hand,

- the share of distribution assets overhead was 1.15 times the mean;
- the reported share of the Company's service territory area in the urban core was well below the mean.

Table 9

How the Model Variables for HON Dx Compare to the Sample Mean (2019)

	HON	Sample Mean	HON / Mean	HON Rank
Cost ($000)				
Total Cost	$ 1,626,272	$ 784,186	2.07	7
OM&A Cost	$ 490,079	$ 230,612	2.13	7
Capital Cost	$ 1,136,193	$ 553,574	2.05	7
Input Prices				
Input Price Index	1.588	1.360	1.17	3
OM&A	1.683	1.280	1.31	1
Capital Price	12.361	11.206	1.10	13
Labor Price	89,696	66,704	1.34	1
M&S Price	139.396	112.348	1.24	1
Real Cost (Cost / Price Index)				
Total Cost	1,023,811	576,658	1.78	
OM&A Cost	291,270	180,233	1.62	
Capital Cost	91,917	49,398	1.86	
Scale				
Customers	1,343,959	1,037,379	1.30	17
Peak Load	6,465	5,174	1.25	18
Ratcheted 10 Year Peak	6,045	5,239	1.15	20
PEG Ratcheted Peak	6,465	5,688	1.14	23
Area	20.25	0.66	30.71	1
Area Measured by Tx Miles	20,783	5,347	3.89	2
Scale Index				
Customers	1.30	1.00		
PEG Ratcheted Peak	1.14	1.00		
Area Measured by Tx Miles	3.89	1.00		
Weight on Customers	70.2%	70.2%		
Weight on Peak	22.6%	22.6%		
Weight on Area	7.3%	7.3%		
Scale Index	1.36	1.00		
Bilateral Productivity Level				
Multifactor	0.768	1.00	0.77	
OM&A	0.843	1.00	0.84	
Capital	0.732	1.00	0.73	
Business Conditions				
Percent AMI	100.0%	50.6%	1.98	1
Percent Forestation	74%	57%	1.30	25
Percent Overhead	91%	79%	1.15	11
Percent Electric	100.0%	88.7%	1.13	1
Gas Customers	0%	162,318	0.00	23
Percent Dx Plant in Total Plant	38.7%	42.2%	0.92	28
Percent Dx Plant in T&D Plant	38.7%	65.9%	0.59	1
Urban Core	0.00%	0.08%	0.00	36

5.4 Econometric Distribution Cost Research

Relying chiefly on Clearspring's data, we developed an alternative econometric model of the total cost of power distributor base rate inputs. We also developed econometric models of distributor opex and capital cost.

Differences from the Clearspring Methodology

The following methods that we used in model development differed from Clearspring's.

- Lacking a good estimate of the area of Hydro One's service territory, we replaced the area variable that Clearspring used with their transmission line length variable. This variable should be highly correlated with distribution service territory and sidesteps the problem of obtaining an accurate value for Clearspring's area variable for Hydro One.
- We mean-scaled all variables.
- We did not use Clearspring's distribution work or scope economy variables and instead used the share of distribution in the sum of T&D gross plant value.
- We benchmarked the OM&A and capital cost of Hydro One as well as its total cost.

Econometric Results

Details of this research are reported in Tables 10-12. In all three models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude.

Econometric results for PEG's distributor total cost model are presented in Table 10. Here are some salient results.

- The parameter estimates for the number of customers, ratcheted peak demand, and area variables are all highly significant and positive. The parameter estimates for all of the quadratic and interaction terms associated with these three scale variables were also highly significant. The relationship of cost to the three scale variables was therefore significantly nonlinear.

Table 10

PEG's Featured Econometric Model of Distribution Total Cost

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTOH =	Percent Overhead Distribution Plant
OHFOR =	Percent Overhead Distribution Plant times Forestation of Service Territory
PCTPDX =	Percent Distribution of Transmission & Distribution Plant
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.072	4.500	0.000
N	0.694	26.320	0.000
D	0.223	15.120	0.000
YL*YL	0.041	3.110	0.006
N*N	0.716	15.090	0.000
D*D	0.884	23.580	0.000
Y*N	0.144	18.650	0.000
YL*D	-0.178	-44.730	0.000
N*D	-0.766	-19.510	0.000
PELEC	0.257	11.290	0.000
PCTOH	-0.104	-1.160	0.262
OHFOR	0.053	8.450	0.000
PCTPDX	0.181	9.700	0.000
AMI	0.011	5.990	0.000
PTCU	0.013	16.210	0.000
Trend	-0.001	-0.680	0.504
Constant	13.153	1224.700	0.000

Adjusted R^2	0.974
Sample Period	2002-2019
Number of Observations	1,171

Pacific Economics Group Research, LLC

- Total cost was also higher the higher was the share of the service territory that was congested and urban, the share of distribution assets overhead x the share of service territory area forested, AMI penetration, the share of electric plus any gas customers that were electric, and the share of distribution in T&D gross plant value.

- The estimate of the trend variable parameter suggests that there was essentially no shift in total cost annually for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.974. This suggests that the model had a high level of explanatory power.

Capital Cost

Details of PEG's distributor capital cost research are presented in Table 11. Here are some key findings.

- The parameter estimates for the number of customers, ratcheted peak demand, and the area variable were all highly significant and positive. All of the parameter estimates for the extra quadratic and interaction terms for the scale variables were also highly significant. This suggests that the relationship of capital cost to the three output variables was significantly nonlinear.

- Distribution capital cost was also higher the greater was the share of the area served that was congested and urban, AMI penetration, the share of distribution plant in the gross value of T&D plant, and the ratio of electric customers to the sum of gas and electric customers.

- Capital cost was lower the greater was the share of lines overhead.

- The estimate of the trend variable parameter indicates that there was no significant shift in capital cost for reasons other than changes in the values of the model's business condition variables. This is noteworthy given the frequent claims by distribution utility witnesses that a need for high capex is pervasive in the distribution industry.

- The 0.968 value of the adjusted R^2 model was very similar to that for the total cost model.

Table 11

PEG's Featured Econometric Model of Distribution Capital Cost

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTPOH=	Percent Overhead Lines
PCTPDX =	Percent Distribution Plant of Transmission & Distribution Plan
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.063	5.960	0.000
N	0.584	29.090	0.000
D	0.368	26.630	0.000
YL*YL	-0.031	-3.920	0.001
N*N	0.510	12.860	0.000
D*D	0.643	15.480	0.000
Y*N	0.095	11.480	0.000
Y*D	-0.054	-4.980	0.000
N*D	-0.573	-16.720	0.000
PELEC	0.205	16.860	0.000
PCTOH	-0.245	-6.390	0.000
PCTPDX	0.393	7.040	0.000
AMI	0.015	6.830	0.000
PTCU	0.015	20.200	0.000
Trend	0.000	-0.520	0.607
Constant	10.677	1355.750	0.000

Adjusted R^2	0.968
Sample Period	2002-2019
Number of Observations	1,171

OM&A Expenses

Results of PEG's econometric distribution opex research are presented in Table 12. Please note the following.

- The parameter estimates for transmission line length, number of customers, and ratcheted peak demand were all significant and positive.[23] Notice that the number of customers had a considerably greater impact on opex than in the total cost model, while peak demand had a much smaller impact. This makes sense since OM&A expenses include many customer-driven expenses like those for metering, billing, and collection.
- The parameter estimates for the additional quadratic and interaction terms associated with the included scale variables were all highly significant. This suggests that the relationship of cost to the three scale variables was significantly nonlinear.
- The share of distribution in T&D gross plant value had the wrong sign so we instead used the share of distribution in total gross plant value less general plant.
- Opex was higher the greater was the share of the service territory that was congested and urban.
- Opex was also higher the higher was system overheading, share overhead x share forestation, AMI penetration, and the share of electric in the sum of gas and electric customers.
- The trend variable parameter estimate indicates a 0.13% annual growth in opex for reasons other than changes in the values of included business condition variables.
- Table 12 also reports a 0.935 adjusted R^2 statistic for the opex model. This is modestly below that for the total cost and capital cost models. Evidently, distributor opex proved more difficult to accurately model that distributor capital cost or total cost.

[23] Ratcheted peak demand was significant using a one-tailed test.

Table 12

PEG's Featured Econometric Model of Distribution OM&A Expenses

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTOH=	Percentage Overhead Distribution Plant
PFOR =	Forestation of Service Territory
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
PCTPDX =	Percent Distribution Plant of Total Plant net General Plant
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.089	4.530	0.000
N	0.799	33.960	0.000
D	0.066	2.680	0.016
YL*YL	0.064	4.510	0.000
N*N	1.280	10.650	0.000
D*D	1.203	10.160	0.000
YL*N	0.136	14.880	0.000
YL*D	-0.218	-12.040	0.000
N*D	-1.172	-10.640	0.000
PELEC	0.153	4.330	0.000
PCTOH	0.701	10.650	0.000
PCTOH*PFOR	0.054	13.140	0.000
AMI	0.006	2.130	0.048
PTCU	0.015	7.150	0.000
PCTPDX	0.283	9.300	0.000
Trend	0.001	0.900	0.379
Constant	11.973	660.470	0.000

Adjusted R^2	0.935
Sample Period	2002-2019
Number of Observations	1,171

Pacific Economics Group Research, LLC

5.5 Econometric Benchmarking Results

We benchmarked the OM&A, capital, and total distributor cost of Hydro One in each year of the historical 2005-2019 period as well as in the 2020-2027 period for which the Company has provided proposals/projections. All benchmarks were based on our econometric model parameter estimates and values for the business condition variables which are appropriate for the Company in each historical and future year.

Tables 13-15 and Figures 4-6 report results of this benchmarking work. For each cost considered, the tables report results for each year and highlight the average results for the last three historical years and the five years of the proposed new Custom IR plan. Recollecting the recent benchmark years for estimating Hydro One's capital cost, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Total Cost

Table 13 and Figure 4 show results of our distribution *total* cost benchmarking. It can be seen that Hydro One's total distribution cost trended downward from 2005 to 2014. Total cost efficiency will improve modestly during the Company's current IR plan and then resume its deterioration. On average, projected/proposed total cost during the new plan will exceed the benchmarks by about 37% during the 2023-2027 term of the CIR plan. From 2023 to 2027, cost efficiency will average a 1.38% annual decline.

Capital Cost

Table 14 and Figure 5 show results of our distribution *capital* cost benchmarking. It can be seen that Hydro One's capital cost efficiency has trended downward since 2002. Efficiency was fairly stable under the current CIR plan but is expected to resume its deterioration in the next plan. On average, projected/proposed capital cost during the new plan will be 71% above our benchmarks for the 2023-27 period. From 2023 to 2027, capital cost efficiency will average a 2.21% annual decline.

Table 13

Year-by-Year Total Distribution Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	20.15%
2003	19.52%
2004	14.17%
2005	16.59%
2006	19.49%
2007	27.85%
2008	26.06%
2009	31.25%
2010	30.64%
2011	32.39%
2012	32.12%
2013	35.89%
2014	38.82%
2015	35.09%
2016	34.97%
2017	33.47%
2018	34.97%
2019	35.43%
2020	33.84%
2021	31.10%
2022	30.41%
2023	34.27%
2024	35.72%
2025	37.61%
2026	38.65%
2027	39.77%
Average 2017-2019	**34.62%**
Average 2023-2027	**37.20%**

Figure 4

Hydro One's Total Distribution Cost Benchmarking Scores

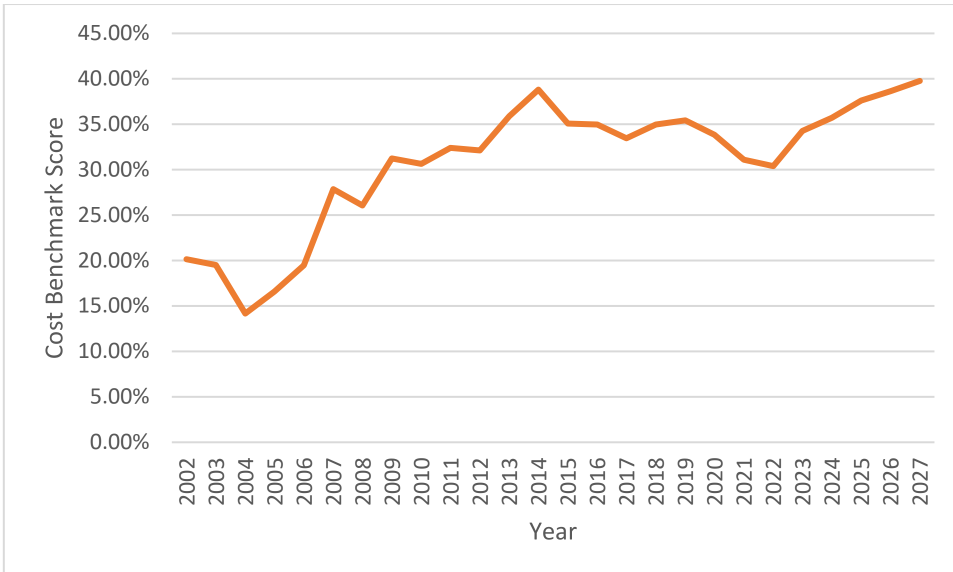


Table 14

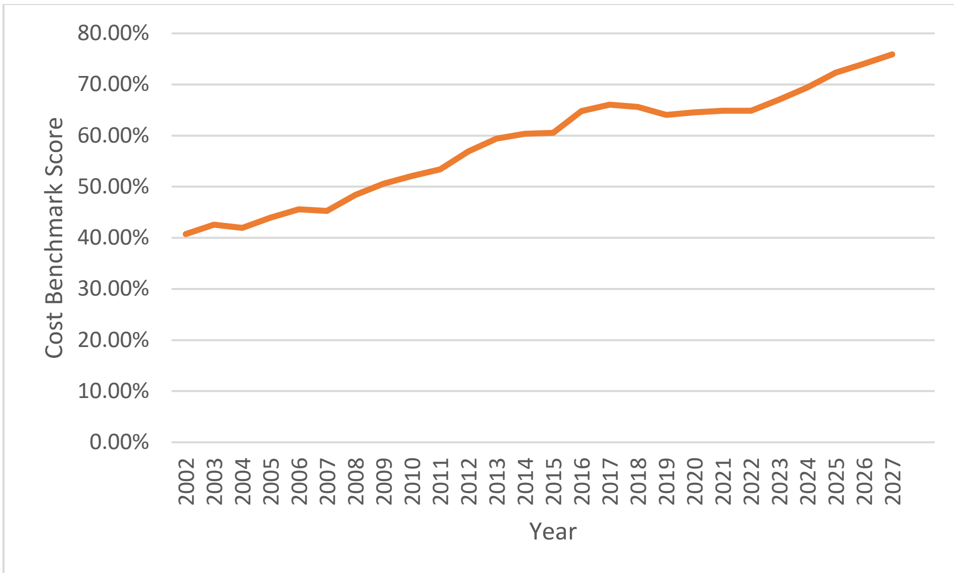
Year-by-Year Distribution Capital Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	40.73%
2003	42.57%
2004	41.94%
2005	43.93%
2006	45.60%
2007	45.28%
2008	48.37%
2009	50.59%
2010	52.11%
2011	53.40%
2012	56.91%
2013	59.42%
2014	60.38%
2015	60.53%
2016	64.81%
2017	66.05%
2018	65.61%
2019	64.07%
2020	64.54%
2021	64.84%
2022	64.87%
2023	67.08%
2024	69.43%
2025	72.34%
2026	74.07%
2027	75.90%
Average 2017-2019	**65.24%**
Average 2023-2027	**71.76%**

Figure 5

Hydro One's Distribution Capital Cost Benchmarking Scores



OM&A Cost

Table 15 and Figure 6 show results of our distribution opex benchmarking. It can be seen that Hydro One's distribution opex efficiency trended downward from 2004 to 2014 but has tended to improve since that time. Improvement is expected to occur during the expiring CIR. Opex efficiency will be markedly worse in 2023 and then resume improvement. On average, projected/proposed opex during the new plan will be 7% below the benchmarks during the 2023-27 Custom IR term. From 2023 to 2027, distribution opex efficiency will average about a 1.2% annual improvement.

Table 15

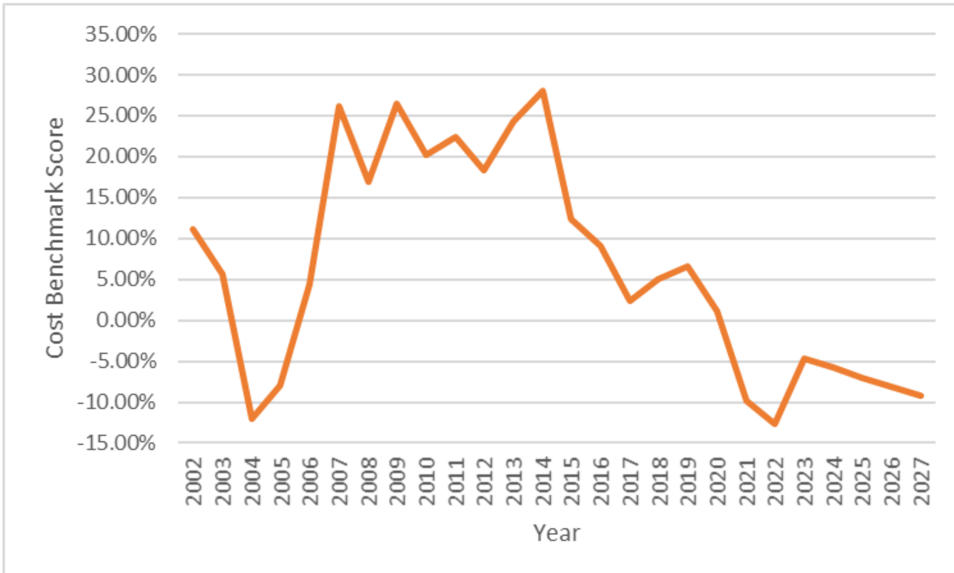
Year-by-Year Distribution OM&A Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	11.12%
2003	5.59%
2004	-12.04%
2005	-7.94%
2006	4.35%
2007	26.20%
2008	16.88%
2009	26.49%
2010	20.25%
2011	22.38%
2012	18.39%
2013	24.31%
2014	27.99%
2015	12.37%
2016	9.15%
2017	2.35%
2018	5.09%
2019	6.54%
2020	1.10%
2021	-9.78%
2022	-12.73%
2023	-4.60%
2024	-5.77%
2025	-6.97%
2026	-8.13%
2027	-9.29%
Average 2017-2019	**4.66%**
Average 2023-2027	**-6.95%**

Figure 6

Hydro One's Distribution OM&A Cost Benchmarking Scores



5.6 Distribution X Factor Recommendations

Stretch Factor

Since performance incentives in U.S. power distribution regulation are not unusually weak, the stretch factor should be based solely on the total cost efficiency of Hydro One's base rate inputs. Hydro One's 37% average total cost benchmarking score over the five years of the new IR plan would be commensurate with a 0.60% stretch factor under Price Cap IR conventions. On the basis of our research, we believe that a 0.60% stretch factor is indicated for Hydro One's distribution services.

X Factor

Assuming a 0% base MFP growth trend, the indicated X factor for Hydro One Distribution is 0.60%.

Scale Escalator

We show in Appendix A.1 that cost theory and index logic suggest that the RCI should provide an allowance for growth in the operating scale of the subject utility. This matters more to the extent that a utility that will be experiencing brisk growth in scale. We support the addition of a customer growth escalator to the RCI for Hydro One Distribution. In the absence of such an escalator expected customer growth is an implicit stretch factor.

6. Other Plan Design Issues

Hydro One's proposed Custom IR framework is similar to those that the Board previously approved in separate proceedings for the Company's T&D services.[24] Some of the proposed provisions are uncontroversial. As in past CIR proceedings that we have participated in, the proposed ratemaking treatment of capital is our chief concern. The various problems we discuss matter especially for transmission, which has an unusually capital-intensive technology.

The C factor would ensure that Hydro One would recover almost all of its projected/proposed capital cost if it incurred this cost. The great bulk of the annual capital cost reduction due to any cumulative capex underspend would be returned to ratepayers. Several additional variance accounts and the Z factor would also address capex. Hence, capital revenue would chiefly be established on a cost of service basis.

The clawback of almost all cost savings from capex underspends and the Y factor and Z factor treatments of some kinds of capex would greatly weaken Hydro One's incentive to contain capex. Incentives to contain capex and opex would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce opex. This is detrimental to the legitimate interests of the Company's employees. The weak incentives to contain capex are inconsistent with the Board's Custom IR guidelines which, as we note in Appendix Section D, proscribe a multiyear cost of service approach to ratemaking and require "explicit financial incentives for continuous improvements and cost control targets," that go beyond the stretch factors used in 4GIRM.

Despite the proposed clawback of most capex underspends, Hydro One would still have some incentive to exaggerate its capex needs. Exaggerations reduce the risk of capex overspends, strengthen the case for a C Factor, and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under

[24] Ontario Energy Board, EB-2017-0049, Decision and Order, Hydro One Networks Inc., March 7, 2019 and EB-2019-0082, Decision and Order, Hydro One Networks Inc., April 23, 2020.

several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted.[25]

Hydro One would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company could somehow manage to time its capex so that the I – X escalation was compensatory, it would obtain no supplemental revenue. This bunching will be more of a concern if and when Hydro One approaches the end of its need for high capex.

Another problem with the proposal is that, while customers must fully compensate Hydro One for the bulk of its expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company would be under no obligation to return any *surplus* capital revenue if in the future it chose to operate under a conventional IRM and its capital cost growth were unusually *slow* for reasons beyond its control. Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex which have provided the rationale for Custom IR will tend to slow future capital cost growth and accelerate productivity growth. Over multiple plans, the revenue escalation between rate cases may therefore not guarantee customers the full benefit of the industry's multifactor productivity trend, even if it is achievable. A possible defense to this line of argument is that the Company intends to operate under CIR continuously.

A related problem is that most of the capex addressed by the C factors and Z factors would be similar in kind to that incurred by the utilities in past and future productivity studies that are used to calibrate Hydro One's X factors.[26] The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

This "double counting" issue has been debated in several IR proceedings and no consensus has been established regarding its remedy. Some regulators have eschewed X factor adjustments for double counting and based X factors on unadjusted *MFP* trends. However, the Hawaii Public Utilities

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[25] See, for example, Ofgem (1999), Reviews of Public Electricity Suppliers, Distribution Price Control Review: Draft Proposals and Ofgem (2009), Regulating Energy Networks for the Future: RPI-X @ 20: History of Energy Network Regulation

[26] Hydro One would not, however, be compensated during the plan for capex overruns.

Commission ruled, in a recent IR proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that their major plant additions will be eligible for cost tracking.[27]

Given Hydro One's weak incentive to contain capex, the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and the Company's incentive to exaggerate capex requirements and bunch capex, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[28] This raises regulatory cost. The need for the OEB to approve multiyear capital revenue requirements greatly complicates CIR proceedings and is one of the reasons why the Board now requires and must review complicated T&D system plans - a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB Staff and stakeholders will inevitably struggle to effectively challenge the Company's capex proposal. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements, without necessarily making the same investment that British (and Australian) regulators have made in the capability for appraising and ruling on multiyear capex proposals.[29]

The substantial compensation for capex funding shortfalls which has been permitted by the OEB under Custom IR may be more remunerative than that available under the ACMs and ICMs featured in 4GIRM. As discussed in Appendix D, these modules feature materiality thresholds that include a modest markdown on capex that is eligible for supplemental revenue. If the markdowns under Custom IR and 4GIRM are imbalanced, utilities may choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though compensatory operation under 4GIRM is feasible.

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

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal

[27] Hawaii Public Utilities Commission (2020), Decision and Order No. 37507, Docket No. 2018-0088.

[28] Proposed programs that raise capex and reduce OM&A expenses merit especially close examination.

[29] Consider, for example, that Ofgem's own view of a power transmitter's required cost growth is assigned a 75% weight in contested IR proceedings. This view is supported by independent engineering and benchmarking.

> of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[30]

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

Informed by our familiarity with Custom IR and by research and testimony in many proceedings outside Ontario, we believe that the following alternatives to the current CIR treatment of capital merit consideration. Consider first that in California many gas and electric utilities have operated over the years under multiyear rate plans with hybrid revenue caps that index OM&A revenue but have a different ratemaking treatment for capital. Consumer advocates are influential there and have sometimes refused to consider in advance the prudence of forecasted/proposed plant additions beyond the (forward) test year. Budgets for plant additions have in several plans been set at the average of recent historical values or the value that is featured in the forward test year.

The Alberta Utilities Commission ("AUC") had an unhappy experience with capital cost trackers to fund capex surges in their first-generation IR plans for provincial gas and electric power distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second-generation plans. The AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

A "K-bar" value was established for each distributor for the first year of the plan based on the extent to its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, were not funded by base rates. K-bar values in subsequent years have been escalated by the growth that would otherwise be produced by the rate or revenue cap index. Capital cost trackers may

[30] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

be requested to provide supplemental funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[31]

Each of these approaches to ratemaking could make sense for Hydro One were it not for one fact: it forecasts plant additions that are well in excess of its recent historical norms. Here are some other ratemaking treatments of capital that merit consideration.

a) One obvious candidate is the approach previously advocated by PEG and chosen by the OEB in some recent Custom IR proceedings. A supplemental stretch factor would apply to the calculation of the C factor. Hydro One has proposed a modest 0.15% supplemental stretch factor in this proceeding.

b) Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives. The IR plans for the Fortis companies in British Columbia track the costs of *all* older capital.[32] A problem with this approach is that they make operation under 4GIRM or its successor more difficult. Hydro One can then claim that only continued operation under CIR can be compensatory.

c) The proposed capex budget could be reduced by a material amount, as in some past Custom IR decisions.

[31] In the first generation of PBR plans in Alberta, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

[32] This is true of the current generation of plans for the FortisBC companies as well as the previous generation. British Columbia Utilities Commission (2020), Decision and Orders G-165-20 and G-166-20.

British Columbia Utilities Commission (2014), "In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018 Decision", Commission Order G-139-14, September 15, 2014.

d) Hydro One could be permitted to keep a portion of the benefit of capex underspends.

e) Some of these approaches could be sensibly combined.

After considering the pros and cons of these options, we recommend that the OEB at a minimum add a supplemental stretch factor to Hydro One's C factor calculation. This factor should be no less than the comparable markdown on plant additions that is produced by the ICM. Several arguments can be advanced for making the supplemental capital cost stretch factor even higher.

- The Board rationalized the 10% markdown factor for ACMs and ICMs chiefly on the grounds that it may reduce regulatory cost. We have ventured a much wider range of arguments in favor of a markdown.
- The 10% markdown factor in the ICM formula actually marks down otherwise-eligible capex by considerably less than 10%.

We also believe that Hydro One should be permitted to keep a share of the annual cost savings from any capex underspends that it achieves. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends, and not the "first" 2% as the Company proposes. The Company should also be permitted to keep a share of the benefits of demonstrated productivity initiatives.

Appendix A: Index Research for X Factor Calibration

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

A.1 Principles and Methods for Revenue Cap Index Design

Basic Indexing Concepts

Input Price and Quantity Indexes

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

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

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

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[33]

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

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

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

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

This greatly simplifies input quantity measurement.

Productivity Indexes

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

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

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Depending on their design, productivity indexes can compare productivity levels of different companies in a given year, measure productivity *trends*, or do both. The growth of a productivity trend index can be shown to be the difference between the growth of the output and input quantity indexes.[34]

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

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

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

Output Indexes

Depending on their design, an output index can compare the output levels of utilities in a given year, measure output trends, or do both. If output is multidimensional in character, its level or trend can be measured by a multidimensional output index. Each output dimension that is itemized is

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

measured by a sub-index, and the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output on *cost.*[35] In that event, the index should be constructed from one or more output variables that measure the "workload" that drives cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity."[36] Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[37] A productivity trend index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

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

The corresponding productivity level index is

$$Productivity^C = Outputs^C / Inputs. \qquad [6b]$$

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[38] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output

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

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

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

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

quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost. The realization of scale economies will typically be lower the slower is output growth. Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be less able than smaller utilities to achieve incremental scale economies from the same rate of output growth.

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

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

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

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

Use of Indexing in Revenue Cap Index Design

Revenue Cap Indexes

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

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C.\text{[39]} \qquad [7]$$

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

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth Input Prices} - (X + S) + \textit{growth Scale}^{Utility} \qquad [7a]$$

where:

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

S = stretch factor

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

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

An alternative basis for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[40] It then follows that

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Outputs}^C \\ &\quad - (\textit{growth Outputs}^C - \textit{growth Input Quantities}) \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C \end{aligned} \qquad [8]$$

Simple vs. Size-Weighted Averages

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

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

Arguments for even-weighted averages include the following.

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

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

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

Dealing with Cost Exclusions

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

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

where

$$X = \overline{Productivity}^{OM\&A}.$$

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

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

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

Scale Escalators

Formula [7a] raises the issue of the appropriate scale escalator for a revenue cap index. For gas and electric power distributors, the number of customers served is a sensible component of a revenue cap index scale escalator, for several reasons. The customers served variable often has the highest estimated cost elasticity amongst the scale variables studied in econometric research on distributor cost. The number of customers clearly drives costs of connections, meters, and customer services and has a high positive correlation with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote demand side management. This is an argument for excluding these system-use variables from a revenue cap index scale escalator.[41] In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

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

$$growth\ Revenue^{Allowed} = growth\ GDPIPI - X \quad [9a]$$

where

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

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDPIPI - X + Stretch^{Augmented} \quad [9b]$$

where

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

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

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

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

Inflation Issues

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

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

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

The GDPIPI is the Canadian government's featured index of inflation in the prices of the economy's final goods and services.[42] It can then be shown that the trend in the GDPIPI equals the difference between the trends in the economy's input price and (multifactor) productivity indexes.

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

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

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

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

Relation [12] has been the basis for the design of several approved X factors in *MRP* plans in the United States.[43] Since the *MFP* growth of the U.S. economy has tended to be brisk it has contributed to the approval of substantially negative X factors in several American *MRPs* for energy distributors. MFP

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

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

growth has historically been slower in Canada's economy, and macroeconomic price indexes are less frequently the sole inflation measures in revenue cap indexes.

Stretch Factors

The stretch factor term of an RCI should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the utility's operating efficiency at the start of the multiyear rate plan. It also depends on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend.

Initial operating efficiency is often assessed in IR proceedings by statistical benchmarking studies. The methods used in these studies run the gamut from unit cost and productivity level metrics like those we presented in Tables 4 and 9 to sophisticated econometric modelling and data envelopment analysis. In succeeding multiyear rate plans, the linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize it for a failure to do so.[44]

In prior testimony, PEG presented results of some incentive power research that it had previously prepared.[45] Results of this research were published by Lawrence Berkeley National Laboratory.[46] We showed that the incentive power of regulatory systems can be increased by efficiency carryover mechanisms and less frequent rate cases and reduced by earnings sharing mechanisms. This model can be used to consider how the frequency of rate cases, the prevalence of earnings sharing, and other aspects of ratemaking for sampled utilities compares to provisions in the multiyear rate plan of the subject utility and what the implications are for the stretch factor.

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

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

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

Most power distributors in Ontario operate under the 4th Generation Incentive Ratemaking Mechanism. The X factor term of the price cap index includes a base productivity growth target and a stretch factor. The stretch factor varies with the outcome of an econometric total cost benchmarking study that is updated annually. As detailed in the table below, the best performers get a stretch factor of zero whereas the worst get a stretch factor of 0.6%.[47] No explicit consideration has to date been paid by the OEB to how the incentive power of a multiyear rate plan differs from that of utilities in the productivity study.

Ontario Energy Board Stretch Factor Assignments

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

A.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on T&D cost because the technology of distribution and (especially) transmission is capital intensive. The annual cost of capital includes depreciation expenses, a return on investment, and some taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

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

$$CK = WK \cdot XK.^{48} \qquad [13]$$

The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes.

In U.S. electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are calculated from these same construction cost indexes and from data on the rate of return on capital.[49] Good construction cost trend indexes have not been available for Canadian utilities for many years.

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between these methods is the pattern of decay in the quantity of capital from the plant additions that are made each year.[50] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue cap indexes.

1. Geometric Decay ("GD"). Under the GD method, the capital quantity is treated as the flow of services from plant additions in a given year. The flow is assumed to decline at a constant rate over time. Plant is typically valued in replacement dollars. Cost is usually computed net of capital gains.

[48] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

[49] If taxes are included in the study, capital prices are also a function of tax rates.

[50] Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile.

A GD capital quantity index is typically combined with a consistent GD capital price that simulates the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. The trend in this capital service price is driven by trends in construction costs and the rate of return on capital.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this constant flow assumption has typically been applied to the total plant additions for assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional cost of service ratemaking.[51] Replacement valuation of plant, capital gains, and use of capital service prices can together give rise to volatile GD and OHS capital costs and prices. The derivation of a revenue cap index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to

[51] The OHS assumptions are more markedly different.

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

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

Appendix B: Additional Information on Research Methods

B.1 Econometric Research Methods

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

Form of the Econometric Cost Model

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

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad [B1]$$

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

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad [B2]$$

Here, for each company h, $C_{h,t}$ is cost, L is the length of transmission lines and D is ratcheted peak demand.

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.[52] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 in function [B1] indicates the percentage change in cost resulting from 1% growth in the length of transmission lines. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

[52] i.e., the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \quad [B3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to output growth to depend the size of the company. The elasticity of cost with respect to output growth may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln L_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

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

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. Most of the second-order terms in our cost models had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures (aka "estimators") are used by econometricians. The appropriateness of each estimator depends on the assumed distribution of the model prediction errors. The estimator that is most widely known, ordinary least squares ("OLS"), is familiar to many, readily available in econometric software, and has good statistical properties under simplified assumptions about the distribution of errors. Another class of estimators, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. When, for example, there is autocorrelation in the error terms, parameter estimates are less precise and the GLS estimator produces more precise parameter estimates. However, OLS estimators are asymptotically unbiased to the extent that the variables in the model are not correlated with excluded relevant variables. In this study we used OLS escalators with robust Driscoll-Kraay standard errors. This removes a source of methodological controversy between PEG and Mr. Fenrick in past CIR proceedings.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost models and reported in Tables 1-3 and 10-12 above therefore vary slightly from those in the models used for benchmarking.

B.2 Substation Data

For the 51 non-Hydro One companies in both Clearspring's and PEG's samples, Clearspring measures an average yearly total of 1,628 more substations than PEG does. This comes out to an average of 32 extra substations per utility per year. Of course, these summary numbers only point to the overall differences. The two datasets align for a number of utilities, and very large differences – up to a 5x increase - occur for others. This error is significant, and since the extent of the mismeasurement depends on how the particular utility reports its data, the extent of the data distortion on the econometric model is not predictable. PEG's question on this issue in the Technical Conference was intended to reflect our concern about the *entire* substation dataset; the two examples were provided as clear demonstrations of the problem. Mismeasurement error causes bias in an econometric model and obfuscates the true cost relationship.

In Clearspring's Undertaking JT-4.05, they indicated that they count multiple rows of identically-named substations as individual observations. This method is demonstrably incorrect; upon careful examination of the data, it is very clear that some companies consistently list a single substation on multiple lines to accommodate detailed listing of transformer data. It is unfortunate, from a data collection perspective, that the Form 1 substation page design encourages listing the transformers individually, forcing utilities to devise their own methods for naming and listing substations housing multiple transformers. Any utility listing their subtotals and totals does so independently and free-form.

However, once the data practitioner is familiar with the structure of the Form 1 page and the data practices the utilities tend to use for this section of the Form 1 report, Clearspring's error can be verified in several ways:

- For the companies with significant overcounting, as a rule the substation line indicates that it reports data for a single transformer. It does not seem plausible that utilities would build a new substation at the same location for each transformer. For example, for the second utility discussed in JT-4.05, to rely on Clearspring's data one must believe there are no fewer than 30 separate transmission substations in a single location, plus a group of 5 entire substations at another location in Spencer, North Carolina, population 3,267. PEG believes it is likely that Clearspring's numbers are much closer to a "number of transformers" variable. While such a variable might be appropriate to consider, it has not been vetted for overall accuracy nor is the name and description accurate.
- The Form 1 Substations page has a column to identify spare transformers; these are also listed on individual lines with the same substation name. It is implausible that utilities construct spare substations to house spare transformers.
- A number of utilities – typically, the ones for which Clearspring's and PEG's data are in agreement – list each substation address one time and then leave the name/address portion blank for the next several lines in which they list each individual transformer. Others in agreement tend to have only one transmission transformer at a given substation, or in a very few cases the utility chooses to fill out their Form 1 in a way that allows them to include multiple transformers on one line.
- Several utilities, including but not limited to the two discussed by Clearspring, often summarize the number of substations, number of transformers, and MVa by category. When comparing the numbers of substations with unique locations, it is clear that the utilities are not generally miscounting their own number of substations.

These issues are apparent in the attached pdf files containing excerpts of the Form 1 substations page for a few utilities in different years. Note that the data for a single line is spread over two pages; the line numbers and pages must be matched up to see the full data.

Alabama Power 2016 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALABAMA POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Flatbridge DS-Near Anniston	DS - Unattended	12.47		
2	Flatbridge DS-Near Anniston	DS - Unattended	115.00	12.47	
3	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
4	Flomaton DS-Near Mobile	DS - Unattended	12.47		
5	Flomaton DS-Near Mobile	DS - Unattended	12.47		
6	Flomaton DS-Near Mobile	DS - Unattended	12.47		
7	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
8	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
9	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
10	Flomaton TS-Near Mobile	TS - Unattended	115.00		
11	Flomaton TS-Near Mobile	TS - Unattended	115.00		
12	Flomaton TS-Near Mobile	TS - Unattended	46.00		
13	Flomaton TS-Near Mobile	TS - Unattended	46.00		
14	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
15	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
16	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
17	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
18	Forbes Road DS-Near Montgomery	DS - Unattended	115.00	12.47	
19	Forestdale DS-Near Birmingham	DS - Unattended	12.47		
20	Forestdale DS-Near Birmingham	DS - Unattended	115.00	12.47	
21	Forestdale DS-Near Birmingham	DS - Unattended	115.00	12.47	
22	Fort Deposit TS-Near Montgomery	TS - Unattended	115.00		
23	Fort Deposit TS-Near Montgomery	TS - Unattended	115.00	46.00	
24	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
25	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
26	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
27	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
28	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
29	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
30	Fort McClellan DS-Near Anniston	DS - Unattended	7.20		
31	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
32	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
33	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
34	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
35	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
36	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
37	Fort McClellan DS-Near Anniston	DS - Unattended	115.00	12.47	
38	Fort Mitchell TS-Near Eufaula	TS - Unattended	115.00	46.00	
39	Fort Rucker DS-Near Eufaula	DS - Unattended	12.47		
40	Fort Rucker DS-Near Eufaula	DS - Unattended	12.47		

Alabama Power 2016 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALABAMA POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
1			Regulator	1		1
25	1		Transformer	1		2
1	1	1	Transformer	1		3
			Regulator	1		4
			Regulator	1		5
			Regulator	1		6
1	1		Transformer	1		7
1	1		Transformer	1		8
1	1		Transformer	1		9
30			Capacitor Bank	1		10
30			Capacitor Bank	1		11
10			Capacitor Bank	1		12
1			Regulator	1		13
20	1		Transformer	1		14
20	1		Transformer	1		15
20	1		Transformer	1		16
20	1	1	Transformer	1		17
37	1		Transformer	1		18
2			Capacitor Bank	1		19
22	1		Transformer	1		20
22	1		Transformer	1		21
30			Capacitor Bank	1		22
20	1		Transformer	1		23
			Capacitor Bank	1		24
1			Regulator	1		25
1			Regulator	1		26
1			Regulator	1		27
1			Regulator	1		28
1			Regulator	1		29
1			Regulator	1		30
1			Regulator	1		31
1			Regulator	1		32
1			Regulator	1		33
1			Regulator	1		34
1			Regulator	1		35
1			Regulator	1		36
22	1		Transformer	1		37
20	1		Transformer	1		38
2			Capacitor Bank	1		39
1			Regulator	1		40

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Pacific Economics Group Research, LLC

Duke Energy 2019 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
2	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
3	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
4	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
5	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
6	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
7	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
8	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
9	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
10	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
11	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
12	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
13	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
14	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
15	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
16	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
17	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
18	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
19	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
20	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
21	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
22	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
23	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
24	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
25	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
26	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
27	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
28	YORK RET YORK SC	DIST	100.00	13.00	
29	YORK RET YORK SC	DIST	100.00	13.00	
30	YORK RET YORK SC	DIST	13.00	2.40	0.60
31	YORK RET YORK SC	DIST	13.00	2.40	0.60
32	YORK RET YORK SC	DIST	13.00	2.40	0.60
33	YORK RET YORK SC	DIST	100.00	24.00	13.00
34	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
35	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
36	TOTAL		225554.96	54961.68	8330.10
37					
38	TRANSMISSION -				
39	GEORGIA	TRANS			
40	NORTH CAROLINA	TRANS			

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
2	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
3	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
4	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
5	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
6	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
7	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
8	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
9	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
10	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
11	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
12	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
13	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
14	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
15	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
16	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
17	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
18	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
19	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
20	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
21	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
22	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
23	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
24	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
25	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
26	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
27	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
28	YORK RET YORK SC	DIST	100.00	13.00	
29	YORK RET YORK SC	DIST	100.00	13.00	
30	YORK RET YORK SC	DIST	13.00	2.40	0.60
31	YORK RET YORK SC	DIST	13.00	2.40	0.60
32	YORK RET YORK SC	DIST	13.00	2.40	0.60
33	YORK RET YORK SC	DIST	100.00	24.00	13.00
34	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
35	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
36	TOTAL		225554.96	54961.68	8330.10
37					
38	TRANSMISSION -				
39	GEORGIA	TRANS			
40	NORTH CAROLINA	TRANS			

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
300	1					1
1	1		AUX			2
29	1		GND	1	28,672	3
29	1		GND	1	28,672	4
8	1					5
8	1					6
12	1					7
30	1					8
30	1					9
	1					10
20	1		1			11
20	1					12
15	1		STU			13
15	1		STU			14
15	1		STU			15
15	1		STU			16
12	1					17
12	1					18
22	1					19
22	1					20
6		1				21
6	1					22
6	1					23
6	1					24
5	1					25
10	1					26
10	1					27
12	1					28
12	1					29
1	1					30
1	1					31
1	1					32
12	1					33
22	1		1			34
12	1					35
86032	2470	204		70	711,745	36
						37
						38
65	1					39
46013	586	30				40

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
23055	421	32				1
69133	1008	62				2
						3
						4
12784	1030	95				5
4115	432	47				6
16899	1462	142				7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
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Empire District Electric 2018 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/13/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	457 Ozark South MO	Trans Unattended			12.47
2	460 Pierce City North MO	Dist Unattended	69.00	12.47	
3	467 Decatur-North AR	Dist Unattended	69.00	12.47	
4	469 Joplin-Silver Creek	Dist Unattended	161.00	12.47	
5	471 Joplin-Kodiak	Dist Unattended	69.00	12.47	
6	477 Joplin-Wildwood Ranch	Dist Unattended	161.00	12.47	
7	602 Bolivar Plant MO	Dist Unattended	69.00	12.47	
8	614 Greenfield	Dist Unattended	69.00	4.16	
9	614 Greenfield	Dist Unattended	69.00	12.47	
10	700 Gravette AR	Dist Unattended	69.00	12.47	
11					
12	109 Subtotal		15342.27	3064.97	263.62
13	29 Substations with Capacity < 10,000		1369.59	301.55	12.00
14	138 Total Substations		16711.86	3366.52	275.62
15					
16					
17					
18	6 Substation	Plant Attended	2280.27	241.65	13.80
19	1 Substations	Trans Attended	161.00	69.00	24.00
20	101 Substations	Dist Unattended	8384.59	1223.27	
21	30 Substations	Trans Unattended	5886.00	1832.60	237.82
22	138 Total		16711.86	3366.52	275.62
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Empire District Electric 2018 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/14/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
10	1					2
22	1					3
22	1					4
22	1					5
22	1					6
22	1					7
5	1					8
6	1					9
22	1					10
						11
5861	167	28				12
136	56	6				13
5997	223	34				14
						15
						16
						17
1727	23	1				18
100	1					19
1825	153	16				20
2345	46	17				21
5997	223	34				22
						23
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Pacific Economics Group Research, LLC

Appendix C: Background on North America's Power Transmission Industry

C.1 Federal Regulation of U.S. Power Transmission

To appraise the relevance of statistical cost research using U.S. transmission data for the situation of Hydro One, it is important to understand some key factors of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken today chiefly by the FERC. Transmitter productivity has been greatly affected by FERC regulation and by state and federal policies.

Unbundling Transmission Service

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

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

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

ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission facilities to an independent system operator ("ISO"). Transfer of control was voluntary and utilities retained ownership of most of their facilities. Several ISOs were formed between 1996 and 2000.

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

In 1999, the FERC pushed for further structural change in markets for transmission services by encouraging formation of regional transmission organizations ("RTOs"). These organizations typically have a larger footprint, serving multiple states while ISOs typically serve a single state. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (now called the Midcontinent ISO) and PJM Interconnection received an RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs still operate in New York, Texas, and California.[53] Many utilities in southeastern, intermountain, and northwestern states are not ISO or RTO members.[54] The FERC still regulates the rates charged by members of ISOs and RTOs.

Energy Policy Act of 2005

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

This is the context in which the Energy Policy Act of 2005 ("EPAct") was passed. It affected transmission capex and many other aspects of transmitter operations. The Act gave the FERC authority to establish mandatory transmission reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection ("CIP") standards, was largely delegated to the

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

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

North American Electric Reliability Corporation ("NERC"), which oversees six regional reliability entities. Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability problems resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators. Concerns about the siting of transmission lines were mitigated by a provision of the Act allowing the federal government to designate "national interest electric transmission corridors" to serve areas of significant transmission congestion.

The EPAct also authorized the FERC to incentivize transmission capex and participation in an RTO or ISO. Specifically, the act required the FERC to adopt rules that would

> (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
>
> (2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);
>
> (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
>
> (4) allow recovery of—
>
> > (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
> >
> > (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[55]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. Permissible incentives included the ability for a transmitter to

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

include 100% of construction work in progress in rate base, ROE premiums for some plant additions, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

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

Formula Rates

Rates for transmission services can be set by the FERC in periodic rate cases. However, transmitters can also obtain mechanisms that reset rates annually to reflect the changing cost of their service following expedited reviews. These cost of service "formula rates" may rely on a transmitter's historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values. Formula rates involve what are essentially comprehensive cost variance accounts.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950.[56] Economies in regulatory cost have been an important reason for their use. Regulatory cost is a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities as well as numerous interstate oil pipelines and natural gas pipelines.

Use of formula rates by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies

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

such as the EPAct which promoted transmission investment and increased attention to reliability. Early adopters of formula rates in power transmission included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

In 2004 about 15 of the 52 sampled U.S. transmitters in our econometric sample operated under formula rates. By 2019 fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during these years. Thus, about two-fifths of the U.S. transmitters in our sample received approval of formula rate plans during this period.

C.2 The Canadian Power Transmission Industry

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

Transmission services of most Canadian utilities are subject to cost of service ratemaking. A notable exception is the CIR plan of Hydro One Transmission, which we discuss in Section D.3 below.

In Québec, a *mechanisme de reglementation incitatif* was required by statute for T&D services of Hydro-Québec.[57] This resulted in the 2019 approval of a multiyear rate plan for Hydro-Québec Transmission ("HQT") which has a 4 year term.[58] This plan provides for escalation of OM&A revenue by the formula I-X+G, where I is a weighted average of labor and non-labor price inflation, the 0.57% X factor was based on judgment, and G is a growth term. The Régie de l'énergie committed to

[57] This provision, Section 48.1 of the Act Respecting the Régie de l'énergie, was subsequently repealed, and Hydro-Québec Distribution now operates under a legislatively-determined multiyear rate plan. The approved plan for Hydro-Québec Transmission has not been affected to date.

[58] Régie de l'énergie D-2019-060.

undertaking multifactor productivity and statistical benchmarking studies during the latter years of the plan.

Capital revenue is addressed through annual filings of HQT's forecast of capital cost. An earnings sharing mechanism addresses overearnings. HQT's share of surplus earnings is tied to its service quality performance (e.g., worse performance would result in greater levels of overearnings being refunded to customers). An off-ramp is available should HQT's earnings vary by more than 125 basis points from the allowed ROE after application of the ESM.

Appendix D: Notable OEB Regulatory Precedents

D.1 Power Distributor Ratemaking

The Early Years

Hydro One's initial distribution revenue requirement was established in 1999. The OEB approved the first generation incentive regulation mechanism ("1GIRM") for an initial 2000-2002 term for provincial power distributors, including Hydro One. This IRM featured a price cap index and an ESM. The Board subsequently delayed implementation of 1GIRM to 2001 and removed the ESM. The OEB later extended 1GIRM to March 2005 to allow the utilities additional time to "explore the incentives for improvements and savings provided by the current PBR regime." However, Bill 210, enacted in December 2002, froze existing distributor rates until May 2006 unless approval was otherwise granted by the Minister of Energy. Rates were adjusted in May 2006 pending the outcome of rebasings that were filed in 2005. Between 1999 and 2006, it follows that Ontario power distributors operated without a rate case or ESM. During this period, utilities had strong incentives to contain costs and some utilities may have responded by deferring capex.

The second-generation IRM used the 2006 rates as a starting point. The Board introduced staggered terms allowing approximately 1/3 of distributors to rebase rates each year between 2008 and 2010.[59] Utilities would thus have up to 3 years on the new price cap index.

The term of the third generation IRM (a/k/a 3GIRM) term was initially fixed at three years plus a rebasing year.[60] Hydro One had its distribution rates rebased for 2008 and in a multiple forward test year rate case for 2010-2011. For 2012 and 2013 Hydro One's rates were set according to the provisions of IRM3.

The Renewed Regulatory Framework ("RRF") (initially known as the Renewed Regulatory Framework for Electricity or "RRFE") resulted from initiatives the OEB began in 2010 to review their

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[59] Due to the staggered nature of rate reviews, a handful of utilities were on IRM 2 as late as 2011.

[60] Some companies operated under 3GIRM as early as 2009, depending upon when their rate rebasing occurred.

policies in the areas of ratemaking, distribution system planning, and performance measurement. The Board stated that the goal of the RRF is

> to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers.[61]

The Board provided three ratemaking options under the RRF: the fourth-generation standard incentive ratemaking mechanism (now called "Price Cap IR"), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach. Rates for 2014 were escalated based on the provisions of Price Cap IR.

Hydro One requested a Custom IR plan in 2013 with a 5 year term, based entirely on forecasts of its costs and revenues. The Board rejected this proposal, explaining that

> The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.
>
> The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.[62]

Provisions for High Capex

No special ratemaking provisions for capital were discussed in the OEB's 1GIRM decision. In 2GIRM, companies proposed a mechanism for supplemental capital revenue called a K-Factor. This was rejected due to a lack of perceived need but distributors were permitted to file a rate case early. The OEB expressed concerns about special ratemaking provisions for capital in its decision.

> In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting,

[61] Ontario Energy Board, *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, filed in Ontario Energy Board Case EB-2010-0379, November 8, 2011, p. 1.

[62] Ontario Energy Board, *Decision,* EB-2013-0416/EB-2014-0247*,* March 12, 2015, p. 14.

> and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[63]

3GIRM contained special provisions for capital called the Incremental Capital Module ("ICM"). The Board described the ICM in its decision as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[64] The OEB set a high bar for approval as amounts were required to exceed a formulaic materiality threshold, meet three need criteria, and be prudent. The materiality threshold was determined formulaically and was intended to be a level of plant additions materially higher than that funded by the price cap index, depreciation, and growth in billing determinants.

The need criteria were that the investments be related to a driver, non-discretionary, and incremental to existing rates. A prudence review of the capex and a decision on the ratemaking treatment of overspending of budgets would occur at the time that the capex is brought into base rates while underspending would result in refunds to ratepayers. Recovery of amounts approved under the ICM was realized via rate riders.

The ACM was developed during the term of 4th generation IR to address concerns that distributors were strategically bunching capex around the year of the rebasing and not in accordance with a prudent asset management program. The Board in its decision discussed the advantages of the ACM.

> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate **enhanced pacing and smoothing of rate impacts**, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

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[63] Ontario Energy Board, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 37. Filed December 20, 2006.

[64] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 31. Filed September 17, 2008 in EB-2007-0673. As Dr. Makholm testified to, this has been amended to remove the requirement of unusual circumstances. His assertion in response to question 21 of his testimony is not verifiable on the public record.

> The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.
>
> When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should **reduce incentives for clustering capital projects around the rebasing year.** Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle….
>
> The ACM approach will also assist in large part to preserve the **regulatory efficiency** of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides **greater assurance of recovery for prudent and appropriately prioritized capital projects** regardless of when the investments might be made. The Board would also expect **improved performance with respect to capital forecasting** both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.[65] [Emphasis added]

As part of its decision to implement an ACM option, the Board reduced the markdown for ICMs, limited the scope of ICMs, and added a means test to prevent capital module requests from distributors that are overearning by more than 300 basis points.

Custom IR Guidelines

In their decision in the Renewed Regulatory Framework proceeding, the OEB sanctioned the CIR approach to ratemaking that is popular amongst larger utilities.[66] Under the Custom IR approach, a distributor-specific rate trend is determined by the Board that is

[65] Ontario Energy Board, *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* EB-2014-0219, September 18, 2014, pp. 11-12.

[66] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012.

> informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts.[67]

The OEB acknowledged that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant."[68]

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides the following guidelines for energy utilities requesting CIR.[69]

> **The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).**
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[70] [Emphasis added]

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[67] OEB, *Renewed Regulatory Framework*, *op. cit*., p. 13.

[68] *Ibid*., p. 19.

[69] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

[70] *Ibid*., pp. 25-26.

First Toronto Hydro Custom IR Proceeding

In its order approving Toronto Hydro's first CIR plan,[71] the OEB approved many of the basic features of subsequent CIR plans, including an earning sharing mechanism ("ESM"), the addition of a C factor to the revenue or (in this case) rate escalation formula ESM, and the refund of capital cost underspends at the end of the plan term. The approved plan had a nearly 5-year term and escalated rates using the formula I – X + C, where I was the inflation factor, X was the sum of a 0% productivity trend and a 0.6% stretch factor, and C was a custom capital factor. The C factor would be reduced by a stretch factor. A symmetrical ESM addressed non-capital related earnings variances outside of a 100-basis point dead band, while a variance account refunded all capex underspends to customers. The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the Custom IR term, without specifying which proposed components were disallowed.

The first Toronto Hydro CIR decision also provided general commentary on what the Board expected Custom IR plans to entail:

> Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. . . **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[72] [Emphasis added]

Presumably then, the OEB is open to further innovations in CIR intended to align customer and utility interests. The OEB further stated that:

> [a] Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. **The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.**[73]

[71] EB-2014-0116

[72] *Ibid*., p. 4.

[73] *Ibid*., p. 5.

Hydro One Distribution's Current Custom IR Plan

The OEB approved a CIR plan for Hydro One Distribution in EB-2017-0049. This decision also suggests a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The Board disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast.

In addition, the OEB ordered Hydro One Distribution to provide reports on various issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, Hydro One Distribution was asked to report at the next rebasing on the actual performance of the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) which resulted from discussing best practices with better performing peers. Hydro One Distribution was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to Hydro One Distribution's C-factor beyond the 0.45% stretch factor that applied to the entire revenue requirement on the basis of econometric benchmarking studies. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[74] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness that the C Factor led to perverse incentives for companies to spend excessive amounts on capital to contain OM&A expenses.[75]

D.2 Power Transmission Ratemaking

The Early Years (1999-2018)

Hydro One's initial transmission revenue requirement was established in 1999 and updated to reflect a change in the Company's allowed rate of return on equity ("ROE") in 2000. After that, the

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

[75] *Ibid*., p. 32-33

Company's revenue requirement was unchanged until 2007. Hydro One subsequently filed transmission rate cases in 2008, 2010, 2012, 2014, and 2016. Each rate case considered two forward test years. Concerns about capex underspending led to the adoption of an In-Service Capital Additions Variance Account which requires the Company to return the revenue impact of underspends to customers.

In EB-2018-0218, the OEB issued a decision that detailed an IRM for transmission services of Hydro One Sault Ste. Marie. This decision includes the following noteworthy provisions.

- An RCI allows revenue requirement escalation based on the formula Inflation less an X factor +/- Z factors. No scale escalator was approved for the RCI formula, and the Board commented that parties had presented insufficient evidence to justify the inclusion of such a term.
- Hydro One's proposed inflation measure was accepted. Weights for the two inflation subindexes are 14% for labor and 86% for non-labor.
- The base productivity trend was set at zero, reflecting in part the OEB's prior decisions and their ongoing desire to keep base productivity trends non-negative. No party had supported a negative base productivity trend, even though both productivity studies presented in evidence reported negative MFP trends for U.S. transmitters.
- The stretch factor was set at 0.3%. The Board chose this value in part because they believed that "a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition."[76]
- Hydro One SSM can request supplemental funding for capex through Incremental Capital Module filings.

The Board later approved the request of Hydro One SSM to escalate its revenue requirement by an RCI for a single year. This RCI had an I-X formula, where the I factor was set at 1.4% and the X factor was set at 0%.

[76] EB-2018-0218, p. 21.

D.3 Hydro One Transmission's Current Custom IR Plan

The current Custom IR plan for Hydro One Transmission is broadly similar to previously-approved CIR plans, though there are some subtle differences. These differences include the use of a revenue cap index rather than a price cap index, different weights for the inflation measure, and a shorter 3-year term.

In its decision, the Board hinted at a wariness of multiyear capital cost forecasts. It expressed concern that the productivity improvements built into Hydro One's forecasts were insufficient given the substantial increase in forecasted capex. In its review of transmission line replacement capex, the Board concluded that

> the increased pace of replacing transmission lines (more than three-fold between 2016-2018 and 2020-2022) has not been justified in view of the fact that the forced outage frequency and duration for overhead conductors has been trending down on average, and the ESL of most conductors has increased from 70 to 90 years according to the EPRI study.[77]

Hydro One's capex budget was cut by more than 10% in the decision. In addition, the OEB expected Hydro One to provide a summary of its internal monthly productivity reports in its next rebasing application.

As part of its decision approving CIR for Hydro One Transmission, the Board added an incremental capital stretch factor of 0.15%. The Board explained its decision as follows:

> This stretch factor is consistent with what the OEB approved for Hydro One's distribution business and is intended to incent the utility to seek additional productivity gains on its forecasted capital plan and budget.
>
> Hydro One's proposal for an incentive rate-setting mechanism application includes a forecast of capital expenditures for each year of the three-year term. Hydro One's transmission business is capital intensive, so this is a large part of revenue requirement that will escalate well beyond the I – X component of the RCI adjustment. The OEB concludes that it is appropriate to include the incremental stretch factor given that the revenue cap framework includes an update to rate base each year based on this forecast of capital expenditures.[78]

[77] Ontario Energy Board, "Decision and Order", EB-2019-0082, April 23, 2020, p. 85.

[78] *Ibid*, p. 39.

In its decision the Board noted that Hydro One's transmission and distribution operations had widely varying cost performances.

> The TFP analysis provided in this proceeding by PSE indicated that Hydro One's total costs for its transmission operations are well below the benchmark expectations. In Hydro One's last distribution proceeding, PSE's analysis showed that Hydro One's average total cost levels for its distribution operations were well above benchmark expectations. The OEB does not have the evidence to make any conclusions about why the same company can have such different results for its operations. There are significant common costs that are allocated between the operations…. The OEB also expects Hydro One to review the different benchmark cost performance between its transmission and distribution operations and provide explanations for this difference in the next rebasing application.[79]

[79] *Ibid*, pp. 32-33.

Appendix E: PEG Credentials

Pacific Economics Group Research LLC is an economic consulting firm based in Madison, Wisconsin USA. We are a leading North American consultancy on incentive ratemaking and statistical research on the performance of electric and natural gas utilities. Our personnel have over seventy years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included several projects in each of the larger populous of Canada.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared IR, productivity, and benchmarking research and testimony in more than 50 proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. In the last few years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Massachusetts, Minnesota, North Carolina, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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