Custom Incentive Rate Mechanism Design for Hydro Ottawa

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1. Introduction and Summary

1.1. Introduction

Hydro Ottawa Ltd. ("Hydro Ottawa" or "the Company") proposed a Custom Incentive Rate-Setting ("Custom IR") mechanism for its power distributor services in a February 2020 application.[1] The mechanism is a multiyear rate plan ("MRP") for 2021 to 2025 that is similar to that which the Ontario Energy Board ("OEB" or "the Board") approved for the Company in 2015 for the 2016-2020 period.[2] After a conventional rebasing of revenue in 2021 using a forecasted test year, a formula-driven Custom Price Escalation Factor ("CPEF") would apply to revenue for operation, maintenance, and administration ("OM&A") expenses for the subsequent four years of the plan. Escalation by the CPEF would depend on an inflation measure, the Company's customer growth, and a two-part X factor consisting of a base total factor productivity ("TFP") trend and a stretch factor. Mr. Steven Fenrick of Clearspring Energy Advisors LLC ("Clearspring") prepared cost and reliability benchmarking research and testimony for the Company which is germane to the choice of the stretch factor.[3]

The revenue requirement for capital would be based on a multiyear cost forecast/proposal. A capital variance account would return to customers any revenue requirement savings due to capex underspends over the plan period. Z factor treatment would be available, subject to OEB review and approval, for unforeseen and externally-driven capex and opex that exceeds a materiality threshold.

Hydro Ottawa is one of Ontario's larger electricity distributors. Its proposed plan raises many of the concerns that the OEB has expressed with respect to other recent Custom IR applications. Careful appraisal of the Company's IR proposal and the supportive statistical cost research is thus warranted. Controversial technical work and proposed IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for the Company and other Ontario utilities in the future.

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[1] EB-2019-0261, Hydro Ottawa Limited Electricity Distribution Rate Application, filed February 10, 2020.

[2] Ontario Energy Board, *Decision and Rate Order*, EB-2015-0004, December 22, 2015.

[3] Steve Fenrick, Clearspring Energy Advisors LLC, *Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability*, September 30, 2019.

The OEB has constructively commented on plan design and statistical cost research in its past multiyear IR decisions.

OEB staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on Clearspring's cost benchmarking work and, if needed, to prepare an alternative study. We were also asked to consider other aspects of the Company's Custom IR proposal. This is the report on our work.

Following a brief summary of our findings, we provide pertinent background information in Section 2. There follows a critique of Clearspring's research and testimony and the presentation of some results of empirical research using our preferred methods and data. We conclude by discussing other features of the Company's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

1.2. Summary

Stretch Factor

The X factor in Hydro Ottawa's proposed CPEF formula is the sum of a 0% base productivity trend and a 0.15% custom stretch factor. The stretch factor proposal is informed by Clearspring's total cost benchmarking work. Using an econometric total cost benchmarking model developed for the study, Clearspring found that the Company's projected/proposed costs over the five years (2021-2025) of the new plan were 7.1% below the model's predictions on average. Clearspring recommends a stretch factor of 0.30%.[4] Excluding two large construction projects, the Company's score during the years of the proposed plan would average a more favorable -12.5%.[5] In a response to interrogatories, Clearspring stated that this alternative analysis was done at the request of Hydro Ottawa. Using guidelines established by the OEB for Price Cap IR stretch factors, the Company's proposal for a 0.15% stretch factor is commensurate with the latter result.

Mr. Fenrick uses benchmarking methods are in many respects like our own. In work for several clients, he has developed some business condition variables that are useful in power distributor benchmarking. Further, his study for this proceeding is free of several concerns that we have raised

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

[5] 1.0-VECC-8 and OEB-10 b).

about his work in other recent OEB proceedings. This greatly reduces the scope of controversy concerning benchmarking methods in this proceeding. Clearspring's benchmarking results are fairly stable with respect to changes in the model specification.

We nonetheless disagree with some of the methods Clearspring used in this study. Here are some of our larger concerns.

- The benchmarking model still does not properly address the complex issue of density.
- Ontario data from pre-MIFRS years are included in the sample.
- The calculation of capital costs for the utilities in the econometric study sample is inaccurate.
- We believe that it desirable to go beyond econometric total cost benchmarking in Custom IR proceedings by benchmarking major cost sub-aggregates such as operation, maintenance, and administration ("OM&A") expenses ("opex") and capital cost.

PEG developed an alternative total cost benchmarking model using our preferred methods. We found that Hydro Ottawa's total cost was about 4.5% below the benchmark on average from 2016 to 2018. This is very close to an average performance. The projected/proposed total cost is about 5% above our model's prediction on average in the five years from 2021 to 2025.

PEG also developed models to evaluate Hydro Ottawa's projected/proposed opex and capital cost. 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 and the Company alike. During the term of the proposed plan, the Company's projected/proposed OM&A expenses would be about 0.5% *below* the model's predictions while the Company's capital cost would be about 12.2% *above* the predictions.

On the basis of our research, we believe that a 0.30% stretch factor is appropriate for Hydro Ottawa, provided that the OEB is comfortable fixing the stretch factor for the full plan term. We do not believe, as a matter of principle, that the stretch factor should be based on a study of costs that exclude major plant additions. The geometric decay capital cost specification that PEG and Clearspring both use in benchmarking is sensitive to the age of plant. This strengthens incentives for utilities to postpone plant additions until they are really needed. Analogous exclusions for once in a generation projects were not made for other companies in the sample.

Productivity Growth Target

Hydro Ottawa's proposal to set the productivity growth target in the CPEF formula at 0% is controversial. This target is based on a study of Ontario power distributor total factor productivity ("TFP") trends which is now many years old and was complicated by the transition of most of these distributors to MIFRS accounting. Furthermore, the proposed CPEF applies only to OM&A expenses. The trend in the OM&A productivity of the US distributors in our sample over the full sample period was 0.27%. In the event that the CPEF applies only to OM&A revenue we believe that this trend should be the base productivity growth target in the CPEF formula.

Scale Escalator

Cost theory and index logic support use of a scale escalator in a revenue cap index.[6]

Fixed vs. Variable CPEF

The ability to adjust revenue growth to changing business conditions without weakening utility incentives is one of the chief advantages of indexed attrition relief mechanisms. The COVID-19 pandemic has made inflation and customer growth in the next few years especially difficult to accurately predict. We accordingly recommend that the Board not approve a fixed CPEF for Hydro Ottawa for the plan term.

CPEF Summary

If the Board accepts Hydro Ottawa's proposal to base capital revenue solely on the approved multiyear capital cost, our recommended CPEF formula is Inflation – 0.57% + G where the X factor is the sum of a 0.27% trend in OM&A base productivity and a 0.3% stretch factor. If, alternatively, the Board opts for a Capital-factor (C factor) approach,, similar to what the OEB has approved for Custom IR plans

[6] Since Hydro Ottawa's proposal is that the CPEF escalates aggregate OM&A expenses, which are then added to the capital-related revenue requirement based on the forecasted rate base, to form each plan year's revenue requirement, the CPEF is akin to a revenue cap adjustment.

for Hydro One distribution[7] and Toronto Hydro,[8] our recommended CPEF formula is Inflation – 0.3% + growth Customers, where the X factor is the sum of a 0% base TFP growth trend and a 0.3% stretch factor.

Other Plan Design Features

We are also concerned with the provisions for supplemental funding of capital in Hydro Ottawa's proposal. The plan is modelled on one which was approved before the OEB issued additional Custom IR guidelines in the *Rate Handbook* and is, in our view, inconsistent with those guidelines. It is also contrary to the spirit of some recent OEB rulings on Custom IR proposals.

The proposed ratemaking treatment of capital cost is especially problematic.

- The capital variance account would greatly weaken the incentives to contain capex. The Company would be perversely incented to spend excessive amounts on capex that slows the growth of its OM&A expenses.
- The capital variance account reduces but does not eliminate the Company's incentive to exaggerate its need for extra capital revenue and to bunch capex in ways that bolster such revenue.
- The OEB and stakeholders are compelled to judge the prudence of several years of forecasted/proposed capital spending. It is difficult and resource-intensive to perform this task well.
- Hydro Ottawa may be overcompensated for its capex. The kinds of capex accorded forecast and variance account treatment are, for the most part, conventional distribution capex that are similar to that incurred by distributors in studies used to calibrate the base productivity trend. Capital cost growth would be fully funded when it is rapid for reasons beyond the Company's control but there would be no counterbalancing obligation for the Company to operate with slower revenue growth if and when its capital cost growth was slow for reasons beyond its control. Thus, customers would never receive the benefit of industry TFP

[7] EB-2017-0049

[8] EB-2018-0165

growth between rate cases, even in the long run and even if it is achievable. The stretch factor would apply only to OM&A revenue.

We discuss in the report several alternative capital cost treatments. A C factor treatment with a supplemental stretch factor like those which the OEB has recently approved for Toronto Hydro and Hydro One Networks is certainly one option worth careful consideration. However, the OEB has shown increasing concern about this approach and some alternative approaches also merit consideration. We provide some discussion of various ratemaking treatments of capital in other jurisdictions.

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.[9] 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.

1.3. PEG Credentials

PEG is an economic consulting firm with home offices on Capitol Square in Madison, Wisconsin USA. We are a leading consultancy on IR and statistical research on energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its

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

> Toronto Hydro indicated that intervenors are asking the OEB panel to either make changes to generic policy through a particular utility's rate application or to fetter the discretion of a future panel. Toronto Hydro also submitted that its proposed ratemaking formula is structurally the same as the one approved in its 2015-2019 Custom IR proceeding. 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)

economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report and principal investigator for the project, is the President of PEG. He has over thirty years of experience as an industry economist, most spent on energy utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity, benchmarking, and other statistical cost research and testimony in over 30 proceedings. A recent study on the productivity trends of U.S. power distributors was published in 2017 by Lawrence Berkeley National Laboratory ("Berkeley Lab").[10] In Canada, Dr. Lowry has played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

[10] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background on Ontario Regulation

In this section of the report we summarize in one place notable aspects of the OEB's evolving approach to incentive rate-setting ("IR"). This review is useful background for the discussions of empirical research and other plan design issues that follow. In particular, it pulls together statements that could guide further reforms to Custom IR.

2.1 Renewed Regulatory Framework

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 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.[11]

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. The Board stated regarding these options that

> [Price Cap IR] is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.
>
> Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index.
>
> The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.[12]

The OEB noted that these three options would have many similarities.

[11] 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.

[12] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 14.

> All three rate-setting methods are based on a multi-year IR mechanism. Each rate method will be supported by: the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations; and benchmarking. Rate applications will be supported by a five-year capital plan that includes consideration of regional infrastructure planning.

The Board stated that this more flexible approach to rate-setting will:

- enhance predictability necessary to facilitate planning and decision-making by customers and distributors;
- better align rate-setting with distributor planning horizons;
- facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and
- help to manage the pace of rate increases for customers.[13]

The OEB issued a *Handbook for Utility Rate Applications* ("*Rate Handbook*") in 2016, expanding the rate-setting principles and options, as the RRF, to all energy sector rate-regulated entities in Ontario,[14]

2.2 Price Cap IR

Many aspects of what is now called Price Cap IR are holdovers from the third generation incentive ratemaking mechanism.[15] These include periodic rate rebasings based on a forward test year, use of a price cap index to escalate rates between rebasings, opportunities for distributors to obtain supplemental revenue for capex, and an off-ramp to address significant earnings variances or unacceptable performances. Some costs are addressed by variance accounts.

The price cap index ("PCI") formula includes an inflation measure, an X factor, and a Z factor. The X factor is the sum of a 0% TFP trend and a stretch factor ranging from 0 to 0.6% which depends on the outcome of an annual total cost benchmarking assessment.

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[13] *Ibid*., p. 10

[14] Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016.

[15] Price Cap IR was previously called the fourth-generation incentive ratesetting mechanism ("4GIRM").

Z factor adjustments to PCI growth may be requested for certain changes in costs which result from unforeseen events that are "generally external to the regulatory regime and beyond the control of management."[16] To obtain Z factor treatment a distributor must prove that the costs for which it requests recovery are related to the Z factor event, not already reflected in its base rates, prudently incurred, and in excess of the Board's materiality threshold. The threshold:

> will be differentiated based on the relative magnitude of the revenue requirement in order to maintain the concept of relative materiality across diverse distributors. Specifically, the materiality threshold will be as follows:
>
> - $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
> - 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
> - $1 million for distributors with a distribution revenue requirement of more than $200 million.

The threshold applies to individual events.[17] If a cost impact is deemed eligible, the entirety of the impact can be funded.

Supplemental funding for capital expenditures ("capex") is available from two Price Cap IR provisions: advanced capital modules ("ACMs") and incremental capital modules ("ICMs"). An ACM may be requested only during rebasing rate cases and addresses projects outlined in the applicant's distribution system plan ("DSP"). An ICM may be requested between rebasing rate cases to address projects not included in a distributor's DSP, projects which have increased substantially in size and/or scope since the approval of the DSP, and projects whose eligibility could not be determined during the rebasing.

The ACM was developed 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.

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[16] Ontario Energy Board, *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, July 14, 2008, p. 35.

[17] *Ibid,* p. 36.

> 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.
>
> 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.[18] [Emphasis added]

For either type of capital module, distributors must demonstrate that the capex driving the supplemental funding request is prudently incurred, material, and the most cost-effective option for ratepayers. Distributors overearning by more than 300 basis points cannot request a capital module.

To demonstrate materiality, the total amount of capex needed must exceed a materiality threshold determined by a Board-approved formula. Supplemental funding is not provided for capex below the materiality threshold. There is thus a dead band in the eligibility of capex for supplemental funding which varies by utility.[19]

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[18] 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.

[19] PEG estimated in a recent Toronto Hydro proceeding that its markdown would be about 3% under an ICM.

The initially approved materiality threshold calculation required a distributor's capex to otherwise exceed the threshold by 20%. The Board provided the following discussion of this provision:

> Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.[20]

In 2016 the percentage by which capex must exceed the materiality threshold was reduced from 20% to 10% as part of a series of changes made to the materiality threshold formula, including revisions that would allow the materiality threshold to be calculated more easily over a multiyear period. The Board explained this reduction as follows:

> [T]he OEB considers that **a dead band remains an appropriate means to allow for appropriate funding for qualifying ACM/ICM projects, while discouraging numerous applications for marginal amounts that the utility would be expected to manage under the RRFE and Price Cap IR framework**. However, maintaining the dead band at 20% may not be responsive to the OEB's RRFE objectives of enhanced distributor planning and effective access to available regulatory tools to facilitate pacing and prioritizing needed capital investments. Furthermore, with the adoption of the multi-year formula…, the OEB concurs that the dead band should decrease.
>
> The OEB has determined that a dead band of 10% is more appropriate in light of the changes being made to the materiality threshold formula, and balancing the need for appropriately funding necessary incremental capital investments while **avoiding numerous marginal applications and providing some protection that amounts are not already in rates**.[21] [Emphasis added]

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[20] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, September 17, 2008, p. 33.

[21] Ontario Energy Board*, Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report*, EB-2014-0219, January 22, 2016, pp. 17-18.

2.3 Annual IR Index

Under this option, a utility could operate for more than five years under a price cap index. The base TFP trend in the index would be zero but the stretch factor would be set at 0.60%. This is the high end of the Price Cap IR stretch factor range. Utilities selecting this option would not be able to seek supplemental funding through a capital module.

2.4 Custom IR

Under the Custom IR approach, a distributor-specific rate trend is determined by the Board that is

> 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.[22]

Further,

> The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame.[23]

and

> planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle.[24]

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

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

[24] *Ibid.*, p. 20.

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."[25]

Since Custom IR plans were sanctioned, the OEB has approved eight plans for transmitters and distributors, rejected 2 outright, and substantially modified another. The designs of attrition relief mechanisms ("ARMs")[26] in these plans fall into three categories: fully forecasted ARMs[27], hybrid ARMs where OM&A revenue is indexed and capital revenue is proposed/projected, and indexation applied to both OM&A and capital revenue but with a provision for extra capital revenue via a C factor. Plans of the first two kinds have typically been outlined in settlements, while the latter category resulted from litigated proceedings.

All three kinds of ARMs have usually been combined with capital cost variance accounts and provisions to asymmetrically return to customers most or all of any revenue requirement savings made possible by capex underspends. The prevalence of these "clawback" mechanisms has been somewhat surprising since they were not a mandated in the Custom IR guidelines. A plan for Enbridge Gas Distribution didn't feature a clawback, though some kinds of capex were tracked.[28]

Early History

The first approved Custom IR plan featured an ARM based entirely on company projections/proposals. This approach, together with the clawback of capex underspends, is similar to that used to regulate power distributors in New York state. The approach subsequently fell from favor in Ontario due, in part, to concerns highlighted by the Board in its 2015 rejection of a Hydro One Networks Custom IR proposal.

> **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

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

[26] Our use of the "ARM" term is an attempt to finesse the fact that some plans have *price* caps and others have *revenue* caps. The ARM term originated in California regulation.

[27] The word "forecasted" is something of a misnomer since distributor capex will frequently be lower if their capex forecasts are not accepted.

[28] Ontario Energy Board, *Decision with Reasons,* EB-2012-0459, July 17, 2014.

> 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.[29] [**Emphasis added]**

The Board expressed similar concerns in its decision to reject a similar Custom IR proposal brought forward by PowerStream in 2016.[30]

First Hydro Ottawa Plan

Hydro Ottawa currently operates under a Custom IR plan detailed in a settlement that the OEB approved in December 2015. A conventional rebasing established rates for 2016. Allowed revenue in subsequent years of the plan has been escalated by a hybrid mechanism.[31] Revenue for OM&A expenses has been escalated by a formula that includes an inflation factor, a 0.14% growth factor, and a -0.30% productivity factor. Capital revenue has instead been based on projections/proposals. A capital investment variance account will asymmetrically return to customers the entirety of cumulative revenue requirement reductions that result from any underspends in system renewal and service, system access, and general plant capex. An Efficiency Adjustment Mechanism acts as a proxy stretch factor if the Company's cost performance as measured using the OEB's econometric total cost benchmarking model materially worsens during the plan. An earnings sharing mechanism ("ESM") asymmetrically shares only surplus earnings and has no dead band. The term of the plan is the five years from 2016 to 2020.

The Efficiency Adjustment Mechanism has been triggered during the plan, as Hydro Ottawa's cost performance slipped in the OEB's benchmarking from Group III to Group IV.[32] During the term of the first Custom IR plan, Hydro Ottawa also transitioned to fixed pricing for residential customers.

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

[30] Oshawa PUC Networks' proposal for a Custom IR plan based entirely on forecasts was modified to include a reopener after the third year.

[31] A plan with a hybrid ARM was also approved in 2015 for Kingston Hydro. To the best of PEG's knowledge, there have been no subsequent Custom IR proposals that featured this kind of ARM prior to the current proceeding.

[32] See Interrogatory OEB-4, Table 1-Staff-4-1. Moving between Group III and Group IV in the OEB's benchmarking under 4thGIRM is associated with a 0.15% increase in the stretch factor. The amount recorded in the efficiency

In its rate application, the Company explained how a need for many years of high capex encouraged it to propose Custom IR, stating that

> Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Hydro Ottawa fully expects this level of annual capital expenditure will be sustained, if not increased through the decade from 2020-2030.
>
> The proposed annual expenditure level is significantly greater than annual expenditure levels set out in previous Hydro Ottawa rate applications but is consistent with the 2013- 2015 capital spend levels for distribution plant… By comparison, between 2006 and 2009, Hydro Ottawa's average annual net expenditure level was approximately $60 million per year (gross expenditure average was $75 million per year).[33]

The Company listed several unique challenges it was facing that drove the need for high capex. These challenges included climate, aging assets, "intensification of development within the urban core and continued suburban growth in the east, west, and southern regions of its service territory."[34] The Company reported that approximately 30% of its assets had reached or exceeded their expected useful life.[35]

As part of the settlement approval process for Hydro Ottawa, Staff made a submission appraising the settlement. While Staff believed that the overall settlement was reasonable, it expressed concerns about Hydro Ottawa's Custom IR ratemaking framework:

> The approach to capital spending, however, does not necessarily accord so clearly with a performance-based rate form: costs to customers associated with capital investments are proposed to be recovered on a cost-of-service basis, based on a used or useful principle, forecast against a rate base agreed-upon for every year of the plan term. The capital expenditure related component of rates is excluded from an explicit stretch or productivity commitment and is not subject to an index approach that has been informed by the company's investment plan commitments.
>
> Such asymmetry between the treatment of OM&A and capital expenses was not the intent of the Custom IR option. Instead, with the onset of the RRFE, the OEB has advocated comprehensive, total cost incentive rate-setting, on the grounds that it

adjustment mechanism was 0.15% of the service revenue requirement for each year that the mechanism was triggered.

[33] EB-2015-0004, Exhibit A, Tab 2, Schedule 1, p. 10.

[34] *Ibid*, p. 4-5.

[35] EB-2015-0004, Exhibit A, Tab 2, Schedule 1, Updated June 29, 2015, p. 4.

> creates stronger and more balanced incentives. As has been argued elsewhere, including during RRFE consultations, an asymmetrical I-X framework applied to OM&A but not to capital may distort incentives, promote sub-optimal investments and alter a distributor's response to cost and revenue changes.[36]

Rate Handbook Guidelines

Subsequent to approving Hydro Ottawa's plan the Board issued the *Rate Handbook* that provides further guidance on the "minimum standards" for Custom IR applications.[37] The Board stated that "there is **no threshold test or eligibility requirement** for a Custom IR application."[38] However, the application must advance the OEB's RRF goals and meet certain standards that include the following.

> **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; <u>explicit financial incentives</u> 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)…
>
> **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…**
>
> **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.**[39] [Emphasis added]

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[36] *OEB Staff Submission on the Settlement Proposal,* EB-2015-0004, pp. 5-6.

[37] *Rate Handbook*, *op. cit*., pp. 18-19 and 24-28.

[38] *Ibid*, p. 25.

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

Recent Custom IR Developments

C Factor ARMs

The third approved type of ARM used in Custom IR has been featured in two Toronto Hydro-Electric Ltd. ("Toronto Hydro") plans and plans for transmission and distribution ("T&D") services of Hydro One Networks. This type of ARM nominally escalates capital as well as OM&A revenue using an index. However, a C-factor term in the escalation formula provides supplemental capital revenue. The C factor effectively compensates the utility for most of the difference between its forecasted capital cost growth and the capital revenue growth that the formula otherwise provides. As approved by the Board in Toronto Hydro's first plan, this effectively permitted the Company to obtain capital revenue growth equal to the approved rate of capital cost growth less the base TFP trend and the stretch factor.

The OEB in its decision approving Toronto Hydro's first Custom IR plan expressed some qualms about the heavy reliance on detailed capital cost forecasts, stating that

> 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 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.[40]

With capital revenue still being addressed on a largely cost of service basis, the OEB, its Staff, and various parties have expressed concerns about regulatory cost and incentives with this approach. In its decision in the Hydro One distribution proceeding the Board stated that:

> Hydro One has argued that the 0.45% stretch factor inherent in the (I – X) adjustment is applied to the revenue requirement, and therefore applies to both OM&A and capital. The difference between the treatment of OM&A and capital with Hydro One's proposal is that funding for OM&A is not based on a forecast of OM&A costs. For OM&A, Hydro One is expected to manage within an increase of less than inflation (I – X) each year, regardless of its forecast costs. This is to incent the company to find productivity improvements. For capital, however, Hydro One has forecast capital expenditures for

[40] Ontario Energy Board, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

each year of the term, and is seeking funding for any incremental capital not funded by the (I – X) adjustment.

> **The OEB expects Hydro One to stretch itself more to find additional initiatives and to consider new approaches to its business. The OEB is therefore imposing an additional stretch factor for the capital factor of 0.15% to incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront**.[41]

The OEB subsequently adopted Custom IR plans with C factors and supplemental stretch factors in decisions on new Custom IR plans for Toronto Hydro and the transmission services of Hydro One. Nevertheless, the Board expressed concerns about this revised approach to Custom IR in their most recent THESL decision.

> The RRF objectives of customer-focused outcomes and continuous improvement were not particularly well serviced under Toronto Hydro's 2015-2019 Custom IR framework. Toronto Hydro made significant investments in its system resulting in increases to rates and declining cost performance. The OEB will be making several changes to Toronto Hydro's Custom IR proposal to increase compliance with the objectives set out in the Renewed Regulatory Framework….
>
> **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**. [42] (emphasis added)

Incentivized Capital Variance Accounts

Capital cost variance accounts in the current Custom IR plans for T&D services of Hydro One have incentive features. One feature allows the company to retain the cumulative revenue requirement savings that result from the first 2% of underspends in each year. This is essentially a dead band that is analogous to the dead bands sometimes seen in ESMs.

[41] Ontario Energy Board, *Decision and Order* EB-2017-0049 Hydro One Networks Inc., March 7, 2019, pp. 32-33.

[42] Ontario Energy Board, *Decision and Order EB-2018-0165 Toronto Hydro-Electric System Limited,* December 19, 2019, pp. 23-24.

Another incentivizing provision allows the company to retain all of the revenue requirement savings resulting from any underspends that can be attributed to verifiable productivity gains until the next rebasing. Verifiable productivity gains are the sum of capital productivity gains and capital-allocated corporate costs; are incremental to productivity initiatives incorporated in the Company's Custom IR plan filing; and must result from a productivity initiative that was approved by Hydro One's management. The resulting underspends must be confirmed by the Board as legitimate productivity gains at rebasing.

The Board discussed these mechanisms in the Hydro One Networks Transmission Custom IR decision.

> The [capital cost variance] account was established to protect customers from potential underspending of Hydro One's capital plan**. The OEB finds it reasonable to have a threshold at 98% to allow Hydro One to manage its operations without a potential penalty from underspending.** The OEB also finds it acceptable during this three-year term to allow Hydro One to adjust the account for identifiable productivity improvements, in order to encourage continuous improvement. The OEB agrees with Hydro One that the OEB panel for its next rebasing application can review these adjustments to determine whether they were true productivity savings and reasonable. The OEB panel for that proceeding can also determine whether the [capital cost variance] account should continue, and if so, whether these productivity adjustments add too much complexity to the account and should be discontinued.[43]

2.5 Hydro Ottawa's New Proposal

Hydro Ottawa's new Custom IR proposal is broadly similar to its expiring plan.[44] The term of the plan would be the five-year 2021-2025 period. Rates for 2021 would be established by a traditional rebasing process that uses a forecasted test year. A hybrid ARM would escalate allowed revenue in subsequent years. OM&A revenue would be escalated formulaically using an index while capital revenue would be based on a multiyear projection/proposal of capital cost.

A Custom Price Escalation Factor for OM&A revenue would be based on a formula that includes a custom inflation factor ("I"), a productivity factor ("X"), and a growth factor ("G").

$$CPEF = I - X + G.$$

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[43] Ontario Energy Board, *Decision and Order EB-2019-0082*. April 23, 2020, pp. 172-173.

[44] We use the term distributor services to encompass distribution and customer (e.g., billing and collection) services.

The proposed inflation measure is similar to that which the OEB adopted for Price Cap IR. Measured inflation measure would be a cost-weighted average of the growth in two inflation subindexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all employees in Ontario ("$AWE^{Ontario}$"). Hydro Ottawa has proposed to change the weights for these two subindexes from the 70/30 in the Price Cap IR to 44.5%/55.5% based on an analysis of the labor/non-labor shares of the Company's gross OM&A expenses for the 2016-2020 period. The Company has also proposed to calculate the inflation factor using historical and projected data for the 2017-2025 period from the Conference Board of Canada. The inflation measure would not be updated during the plan, instead being fixed at 2.26%.[45]

The proposed X factor would be fixed as the sum of a 0% total factor productivity ("TFP") component and a 0.15% stretch factor component. The 0% TFP factor would be based on the OEB's Price Cap IR decision and a more recent OEB precedent. The 0.15% stretch factor is based on a Clearspring benchmarking exercise that excluded costs of the sizable Company's Facilities Renewal Program ("FRP") and Cambrian Municipal Transformer Station ("MTS") projects, which the Company notes "do not occur on a regular basis."[46] Clearspring instead recommended a 0.30% stretch factor based on a benchmarking run that retained these costs.[47]

The G factor would compensate Hydro Ottawa for "the increased costs associated with its substantial and steady customer growth."[48] The Company's proposal to fix the value of G at 0.40 is based on the 1.34% growth trend in its historical and forecasted customer count from 2013 to 2020 and the fact that approved customer growth escalators in two Canadian jurisdictions have been marked down.[49]

[45] See Interrogatory Response to OEB-5. Hydro Ottawa acknowledged some errors in calculations, and provided a corrected measure of 2.33%. However, Hydro Ottawa proposed to maintain the 2.26% forecast as being favorable to customers.

[46] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, p. 19

[47] Clearspring Report and IRRs 1.0-VECC-8a, OEB-10 b) and OEB-13, *op. cit.*

[48] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, p. 20.

[49] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, pp. 20-24.

Hydro Ottawa proposes to freeze the value of the CPEF at 2.51% during the plan. This would reflect the fixed 2.25% inflation factor less the 0.15% X factor plus the 0.40% G factor.

Several of the Company's costs would be addressed by variance accounts. These would include expenses for pensions and other post-employment benefits. Most costs of conservation and demand management ("CDM") programs would continue to be funded by Ontario's Independent Electricity System Operator rather than through rates.[50] A lost revenue adjustment mechanism would compensate Hydro Ottawa for load losses due to CDM programs.

A capital variance account would separately track variances in the cumulative revenue requirement arising from four kinds of capex: System Access, System Services, System Renewal, and General Plant.[51] Reductions in the cumulative revenue requirement would be passed through to customers at the end of the plan. The depreciated balance of any capex overspends would be considered for recovery in the next rate case.

Hydro Ottawa would retain the option to request Z factor adjustments to its revenue if qualifying events occur, based on the OEB's existing Z factor policy. Qualifying events must be difficult to foresee, outside the Company's control, and have a cost impact that exceeds a materiality threshold. The threshold for Hydro Ottawa would be $1 million or more per event.

An ESM would asymmetrically share surplus earnings when the ROE exceeded the Board-approved target by more than 150 basis points. This proposed mechanism adds a 150 basis point dead band to the Company's current ESM. For each year, the ratepayer share (50%) of any overearnings would be calculated and added to a deferral account. At the end of the plan term, the deferral account balance would be refunded to customers.

Hydro Ottawa has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if earnings variances exceed the OEB-approved rate of return on equity by more than 300 basis points in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This

[50] The current CDM framework is set to expire at the end of 2020.

[51] A symmetric variance sub-account for system access capex is rationalized on the grounds that "capital spending in this category is driven by customer requests and is therefore difficult to predict, as the level of required expenditure is outside Hydro Ottawa's control.

review would be prospective in nature and could result in modifications to the plan, the plan continuing without changes, or the termination of the plan.

The Company proposes to add 16 metrics to its existing performance scorecard. Each of these metrics is associated with a target, which may be to monitor, improve, or maintain performance. Hydro Ottawa has proposed to terminate its asymmetric efficiency adjustment mechanism.

3. Principles for Revenue Cap Index Design

Revenue cap indexes featuring productivity offsets play a key role in both Hydro Ottawa's proposed approach to Custom IR and the alternative "C factor" approach used by other distributors. This section of the report considers some technical and theoretical issues in research to develop revenue cap indexes and productivity growth targets.

3.1 Productivity Research and its Use in Regulation

Productivity Indexes

A productivity index is the ratio of an output (quantity) index ("Outputs") to an input index ("Inputs"). Growth in a productivity trend index is then the difference between output and input growth:

growth Productivity = growth Outputs – growth Inputs. [1]

Productivity grows when output rises more rapidly than inputs.

The scope of a productivity index depends on the array of inputs addressed by the Inputs. *Partial* factor productivity indexes measure productivity in the use of certain inputs such as capital or labor. A *multifactor* productivity index ("MFP") measures productivity in the use of multiple inputs. In Ontario, these are usually called *total* factor productivity indexes even though indexes calculated for ratemaking in Ontario have never to our knowledge addressed the productivity of all inputs.

The output index of a company measures growth in its output. If the index is multidimensional, the growth in each output dimension which is itemized is measured by a subindex, and growth in the summary index is a weighted average of growth in the subindices. In designing an output index, choices concerning subindices and weights should depend on the way the index is to be used. One possible objective of output research is to measure the impact of output growth on *cost.*[52] In that event, the index should be constructed from one or more output variables that measure dimensions of the

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

"workload" that drive cost. A productivity index calculated using a cost-based output index ("*Outputs*^{C}") will be denoted as *Productivity*^{C}.

If there is more than one output variable in an *Outputs*^{C} index, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and econometric cost research. A classic study by Denny, Fuss, and Waverman has been influential in this literature.[53] This team included a University of Toronto economics professor.

Research has found the sources of utility productivity growth to be diverse. One important productivity driver is technological change. New technologies permit an industry to produce given output quantities with fewer inputs. A second important productivity growth driver is economies of scale. These economies are realized in the longer run if inputs tend to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower when output growth is slower. Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as an enterprise grows beyond a certain point.

A third driver of productivity growth is X inefficiency --- 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 higher is its current inefficiency.

[53] See Michael Denny, Melvyn A. Fuss, and Leonard Waverman, *The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications*, in PRODUCTIVITY MEASUREMENT IN REGULATED INDUSTRIES, at 172-218 (May 12, 1981).

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. Productivity indexes are, therefore, sometimes considered to be measures of efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous business conditions other than input price inflation and output growth which drive cost.[54] A clear example for a power distributor is forestation. If forestation increases in a distributor's service territory due, for example, to a decline in the acreage of open fields[55], more inputs are needed for line clearance. Cost growth will then accelerate and productivity growth will slow.

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 replace aging plant. If a utility requires unusually high replacement capex (a.k.a. "repex"), productivity growth can be unusually slow and even decline. MFP growth of gas and electric power distributors is especially sensitive to repex for several reasons.

- Distribution technology is capital-intensive.
- Highly depreciated assets valued in historical dollars are typically replaced with assets designed to last for decades which must conform to the latest performance standards. These standards typically exceed any that were previously applicable and may incorporate new technologies. Contributions in aid of construction are usually not provided for repex.
- Under the cost of service accounting traditionally used in North American ratemaking, the cost impact of repex is magnified. Assets are valued in historical dollars.
- There is typically no counterbalancing growth in measured output.

On the other hand, productivity growth can accelerate after a multiyear surge in repex as the replacement assets depreciate and growth in the rate of return component of capital cost slows.

[54] To better understand this result, consider that a productivity index is the ratio of an output index to an input index. The quantity of inputs that a utility uses depends on various external business conditions as well as its efficiency. Thus, productivity growth is sensitive to changes in business conditions as well as to changes in efficiency.

[55] Acreage may decline due to suburbanization and the declining competitiveness of agriculture in a district.

This analysis has some notable implications. One is that productivity trends of individual utilities can differ from industry norms for reasons that are beyond their control. Another implication is that productivity indexes are not pure measures of operating efficiency. Productivity can decline for reasons other than declining efficiency.[56] A distributor's efficiency can continuously improve despite negative productivity growth. This could occur, for example, if TFP growth averaged -0.4% annually for several years when a typical distributor would achieve -0.8% growth. A further implication is that regulators need not restrict productivity growth targets in ARM formulas to be non-negative when achievable productivity trends are likely to be negative for external reasons. A more realistic goal is that productivity growth decline by the typical amount expected under adverse business conditions.

Use of Index Research in Regulation

Revenue Cap Indexes

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

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Scale}^{C}.\ ^{57} \qquad [2]$$

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

$$\textit{growth RCI}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility} \qquad [3a]$$

where:

$$X = \overline{TFP^{C}} + \text{Stretch}. \qquad [3b]$$

[56] The ratio of outputs to inputs intuitively *does* seem like a pure efficiency measure. Outputs are, after all, an important driver of cost and productivity will rise if efficiency improves. However, outputs are not the only external business conditions that drive cost. Suppose for example that utility cost is also a function of the number of trees in the service territory. We could then hypothetically measure efficiency by taking the ratio of trees to the quantity of inputs. More efficient utilities would tend to have higher scores. However, this metric would not control for the large differences that exist in the output of utilities in the sample.

[57] *See, e.g.*, Denny, Fuss, and Waverman, *op. cit.*

Here RCI is the revenue cap index. $Scale^C$ is the scale escalator. X, the "X factor," reflects a base TFP growth target ("$\overline{TFP}$") that is typically the recent historical trend in the TFP^C of a regional or national sample of utilities. Notably, a consistent cost-based output index should be used in the supportive productivity research. A stretch factor is often added to the formula which slows RCI growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the MRP.[58]

An alternative basis for an RCI can be found in index logic. It can be shown 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 ("Input Quantities"):[59]

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Input Quantities}. \quad [4]$$

We can then obtain the same result as [2] since

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Scale}^C - (\textit{growth Scale}^C - \textit{growth Input Quantities}) \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C. \end{aligned}$$

Note that both of these formulas can apply to *components* of total cost. The trend in OM&A expenses, for example, can be decomposed as

$$\begin{aligned} \textit{growth Cost}^{OM\&A} &= \textit{growth Input Prices}^{OM\&A} \\ &\quad - \textit{growth Productivity}^{OM\&A} + \textit{growth Scale}^{OM\&A}. \end{aligned} \quad [5]$$

Scale Escalators

These results suggest that RCIs should by some means reflect actual or expected growth in the output of each subject utility. This matters more to the extent that the subject utility is experiencing rapid growth. Growth in scale can be addressed by an explicit scale escalator or an X factor adjustment for expected growth in scale. If the RCI does not compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor in the formula.

Some readers may find an alternative demonstration of the relevance of output growth to the design of ARA formulas persuasive. Equation [4] suggests that, if a revenue cap index compensates a

[58] In some jurisdictions (e.g., Massachusetts) the X factor and stretch factor terms are separate.

[59] This result is due to the French engineer and economist Francois Divisia (1889-1964).

utility only for input price inflation less productivity growth, it will generally not provide sufficient compensation for input *quantity* growth even if the productivity growth trend is zero since input quantity growth also depends on output growth.

Formula [3a] raises the issue of the appropriate scale escalator for an RCI. One issue in the development of a scale escalator is which scale variable(s) to use. For gas and electric power distributors, the number of customers served is a sensible component of an RCI scale escalator, for several reasons. The customers variable usually has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distributor cost. The number of customers served clearly drives costs of connections (e.g., meters and services) and customer services (e.g., billing and collection) and has traditionally been highly correlated 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 CDM. This is an argument for excluding these two system use variables from an RCI scale escalator. In choosing a scale escalator for a North American power distributor, it is also pertinent that data on miles of distribution line, another candidate for inclusion in the scale index. are not readily available for most U.S. power distributors.

Relation [4] can be expanded to obtain the following result:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Input Quantities} + (\textit{growth Customers} - \textit{growth Customers}) \\ &= \textit{growth Input Prices} - (\textit{growth Customers} - \textit{growth Inputs}) + \textit{growth Customers} \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^N + \textit{growth Customers.} \end{aligned}$$

Here $\textit{Productivity}^N$ is a productivity index that uses the number of customers to measure output. This result provides the rationale for the following RCI formula:

$$\textit{growth Revenue}^{Allowed} = \textit{growth Input Prices} - X + \textit{growth Customers} \qquad [6a]$$

where:

$$X = \overline{TFP}^N + Stretch.[60] \qquad [6b]$$

[60] A mathematically equivalent formula is:

$$\textit{growth Revenue} - \textit{growth Customers} = \textit{growth }(\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \qquad [6c]$$

Table 1 details North American RCI precedents. It can be seen that twelve of the twenty-one approved RCIs that we identified have had explicit scale escalators. Most of these RCIs have applied to energy distributor services. The number of customers has been used in all of these escalators and was used exclusively in 10 of the twelve. Three of the twelve escalators have featured a percentage markdown on customer growth. These applied to utilities in BC and Québec.

Since, additionally, Hydro Ottawa has proposed a sizable markdown of its customer growth the rationale for markdowns merits some discussion. One rationale is that output growth is multidimensional and growth in some outputs is expected to be flat during the MRP term. For example, growth in peak demand might be flat, due to a large CDM program, despite customer growth. Another rationale is that output growth has a bigger impact on cost in the long run than in the short run. Customer growth has less cost impact to the extent that it doesn't occasion expansion of the distribution grid.

This is sometimes called a "revenue per customer" index.

Table 1

Summary of Approved Revenue Cap Indexes Informed by Cost Trend Research

Applicable Services	Utility	Jurisdiction	Plan Term	Scale Escalator(s)
Gas Distribution	Southern California Gas	California	1997-2002	Customers
Gas Distribution	BC Gas	British Columbia	1998-2000	Customers, Service Line Additions, etc.[2]
Power Distribution	Southern California Edison	California	2001-2003	Customers
Bundled Power Service and Gas Distribution	Pacific Gas and Electric	California	2004-2006	None
Gas Distribution	Southern California Gas	California	2005-2007	None
Gas Distribution	Gaziféré	Québec	2006-2010	Customers
Gas Distribution	Vermont Gas Systems	Vermont	2006-2009, extended to 2015	Customers
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Customers
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	None
Power Distribution	Green Mountain Power	Vermont	2010-2013	None
Gas Distribution	Gaziféré	Québec	2011-2015	Customers
Gas Distribution	All Distributors	Alberta	2013-2017	Customers
Bundled Power Service	FortisBC	British Columbia	2014-2019	Customers * 0.5
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	0.5* Customers, 0.5* Service Line Additions[2]
Gas Distribution	All Distributors	Alberta	2018-2022	Customers
Power Distribution	Eversource Energy	Massachusetts	2018-2023	None
Power Distribution	Hydro-Québec	Québec	2018-2022, Terminated in 2019	Customers * 0.75
Power Distribution	Hydro One Networks	Ontario	2018-2022	None
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	None
Power Distribution	National Grid	Massachusetts	2019-2024	None
Power Transmission	Hydro One Networks	Ontario	2020-2022	None

[1] Shaded plans have expired.

[2] There are separate revenue cap indexes for O&M expenses and various kinds of capex in these plans that in some instances have different scale escalators. For example, the annual scale escalator for services capex is the number of service additions.

4. Clearspring's Benchmarking Research

4.1. Summary of Clearspring's Work

Clearspring benchmarked the total cost of Hydro Ottawa's base rate inputs. The study appraised the Company's historical total costs over the 13-year period from 2006 to 2018 and its projected/proposed costs for the 2019-25 period. The component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capex were not separately benchmarked.

An econometric model provided the cost benchmarks. Clearspring developed this model using data on power distributor operations of 81 investor-owned utilities ("IOUs") in the United States and of Hydro Ottawa and six other large Ontario distributors that serve urban areas. The sample period for the U.S. utilities was 2002-17 while the sample period for the Ontario utilities was 2006-17. The model has two scale variables: the number of customers served and ratcheted maximum peak demand. 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 also contained the following variables that measure several other drivers of distributor cost.

- share of the service territory area that has urban congestion;
- share of customers with advanced metering infrastructure ("AMI");
- customer density (number of customers/service territory area);
- prevalence of extreme temperatures;
- share of electric customers in the sum of gas and electric customers served;
- estimated share of the service territory that is forested; and
- standard deviation of service territory elevation.

The model also contains a trend variable.

With respect to the form of Clearspring's cost model, the model contains a full complement of quadratic and interaction terms (e.g., Customers^2 and Customers x Ratcheted Peak Demand) for the two scale variables in addition to their first-order terms (Customers and Ratcheted Peak Demand). This form is common in econometric cost models. Clearspring also adds quadratic terms for the congested urban and rural density variables. All parameter estimates 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 Ottawa's total costs were well below the benchmarks yielded by its model in the early years considered (e.g., 2006 to 2010). However, the Company's cost performance eroded steadily. Cost was 10.4% below the model's prediction in 2015, the last year prior to the start of Hydro Ottawa's current Custom IR plan, and is forecasted to be 5.6% below the model's prediction in 2020, the last year of the plan. Projected/proposed costs would be only 7.1% below the model's predictions on average during the five years of the new plan. The cost performance would actually improve slightly to -8.9% in the last year of the plan.

At the Company's request, Clearspring also benchmarked the residual cost resulting if annual costs of two sizable capex projects, the Facilities Renewal Program and the South Nepean Transformer Station, were excluded. Cost would be 12.5% below the model's prediction on average during the years of the plan. On this basis, and in conformance with the OEB's Price Cap IR guidelines, Hydro Ottawa has proposed a fixed 0.15% stretch factor during the full term of the plan, although Clearspring recommended a 0.30% stretch factor.[61]

Clearspring also benchmarked Hydro Ottawa's reliability. Econometric models were developed for the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") using U.S. data. These models control for various business conditions, such as forestation and undergrounding, which affect reliability. The models were developed using data from utility reports to state regulators, Form EIA 861, and the OEB. Benchmarking work using these models suggests that the Company was for many years a markedly inferior SAIFI performer but a superior CAIDI performer. SAIFI performance improved noticeably during the first three years of the current IR plan.

[61] See discussion on page 2 and footnotes 4 and 5.

4.2. Critique

Clearspring Cost Benchmarking

Mr. Fenrick uses benchmarking methods that are in many respects like PEG's. For example, we both favor the econometric approach to benchmarking and believe that total cost benchmarking using a geometric decay approach to the measurement of capital cost is worthwhile in rate applications. Mr. Fenrick has attempted, over several Ontario projects, to develop some useful business condition variables.

In this study for Hydro Ottawa, it is also notable that Mr. Fenrick has changed his benchmarking methodology in ways that address various concerns that we have raised with his work in recent Ontario proceedings.

- The number of quadratic and interaction terms has been reduced.
- Attention to urban and rural cost challenges is more balanced.
- The model does not contain a system undergrounding variable.
- The construction cost was levelized in the correct year.

We nonetheless disagree with some of the methods Clearspring used in this study. Our concerns range from "medium-sized" to concerns that are small but nonetheless notable. We discuss our larger concerns first to facilitate the Panel's review since some panel members may not have an interest in smaller issues.

<u>Medium-Sized Concerns</u>

Capital Cost Power distribution technology is capital-intensive, so the treatment of capital is a major issue when benchmarking total cost. Clearspring, like PEG, used a "monetary" approach to the calculation of capital cost.[62] This uses price indexes to deflate the asset values utilities report (e.g., their gross plant additions). Clearspring used regional American Handy Whitman Electric Utility Construction Cost Indexes ("HWIs") for power distribution for the U.S. and Ontario utilities alike.[63] They attempted to

[62] Monetary approaches to measuring capital cost are discussed further in Appendix Section A.1.

[63] The HWI applied to Ontario was that for the North Atlantic region.

make HWIs more relevant to Ontario by adjusting each value for U.S./Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD").

The appropriate asset price deflator to use in Ontario utility cost research has become an important issue. One reason is that Statistics Canada stopped computing Electric Utility Construction Price Indexes ("EUCPIs") after 2014. These had been available for power distribution and substation assets. The trends in the EUCPIs in the decade prior to 2014 were implausible.

PEG had used the EUCPIs in a number of cost studies for the OEB and spent considerable time and effort during the recent Hydro One distribution IR proceeding reviewing alternative replacement asset price deflators.[64] We found that HWIs and EUCPIs have both had drawbacks. Both indexes were designed many years ago and have cost-share weights and inflation subindexes that are now inappropriate. The labor price component of the distribution system EUCPI grew quite slowly in the later years of its calculation. However, trends in the prices of labor and construction in the North Atlantic states may not be appropriate for Hydro Ottawa and other Ontario utilities. For example, the HWI would be sensitive to a surge in power transmission capex that put upward pressure on distribution construction costs in the North Atlantic region. Purchasing power parities ("PPPs") calculated for the entire economy may not satisfactorily adjust for differences in Ontario and northeast U.S. construction cost trends.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario energy distributor cost research is Statistics Canada's implicit capital stock deflator ("ICSD") for the Canadian utility sector.[65] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This data collection program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from various sources including the Capital Repair and Expenditures Survey. Our research showed that this index tracked the EUCPI in its good years better than the HWI with a PPP adjustment.

[64] EB-2017-0049, Exhibit L1, Tab 8, Schedule HONI-14 Attachment.

[65] Statistics Canada, 36-10-0096-01, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

However, the utility sector of Canada's economy includes power generation and transmission, gas distribution, and water and sewage utilities as well as power distributors. We acknowledge that the growth trends in power distribution HWIs and the Canadian ICSD for the utility sector have differed markedly in some recent years. For the purpose of this transnational benchmarking project, which relies chiefly on U.S. data, we accordingly assume that power distributor asset price inflation in Ontario is a simple average of the inflation of the power distribution HWI for the North Atlantic states and the Canadian ICSD for the utility sector.

We discuss in the Appendix how the accuracy of statistical cost research using "monetary" capital cost specifications is increased by using an early "benchmark" year to begin calculating capital cost. Clearspring used a 2002 "benchmark" year to calculate the capital costs of Hydro Ottawa and the other Ontario distributors, even though a 1989 benchmark year is feasible for these distributors. This reduces the accuracy of their benchmarking work, especially in the early years of the sample period.

Density Issues Clearspring uses an urban congestion variable in its model. We prefer to call this an "urban challenge" variable because the cost of urban service is materially raised by high reliability requirements in office districts as well as by congestion problems. Our other concerns about the variable that Clearspring developed include the following.

- Toronto Hydro Electric and Consolidated Edison of New York ("Con Ed") have by far the highest values for Clearspring's urban challenge variable. If these two companies have unusually poor cost performances the variable's parameter estimate would reflect this.

- The area of the service territory is a legitimate candidate for treatment as an output variable with a full complement of second order terms (e.g., area x area and area x customers). This can capture the cost impact of high and low customer density. When this treatment is added to the model it receives strong statistical support and the %CU parameter estimate is much less significant.

- It seems equally sensible to use the estimated urban area as the variable in a cost model since cost will clearly be higher the larger is the urban area served. However, when we tried this in models the parameter estimate was negatively signed.

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

- Data going back to 2006 are used from the Ontario distributors, but all but one of these distributors transitioned to MIFRS accounting between 2011 and 2015. The change from Canadian GAAP to MIFRS materially raised their OM&A expenses but did not have a commensurately large (offsetting) effect on capital cost.

- 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. OM&A benchmarking is especially pertinent inasmuch as the CPEF applies only to OM&A expenses.

- Statistical tests revealed the presence of first-order autocorrelation in the data. This reduces the "efficiency" of parameter estimates – their tendency to be close to the true parameter values. In the econometric literature, efficiency is considered to be an important criterion for choosing an estimation procedure (aka "estimator") along with bias. The minimum variance linear unbiased estimator, for example, is called the *best* linear unbiased estimator. Clearspring did not correct its estimates of model parameters for autocorrelation. Its procedure for estimating model parameters was therefore inefficient.

<u>Smaller Concerns</u>

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, future benchmarking studies, for Hydro Ottawa and other utilities, which steer clear of these problems will have more credibility.

- Clearspring used a 1989 benchmark year to begin calculation of the capital cost of all U.S. utilities in the econometric cost sample even though a 1964 benchmark year is feasible for the U.S. distributors. The cost of gathering the requisite U.S. capital data for a 1964 benchmark year is non-negligible, but Clearspring has expended effort to develop several complicated business condition variables over several proceedings.

- The forestation variable Clearspring used was poorly documented and used a different definition of area than the density variable. As well, this variable is sensitive to forestation in the rural areas that surround the urban areas where most of a distributor's customers frequently live. The cost impact of forestation depends on the extent to which lines are overhead. The exercise was performed for 2009, and the extent of forestation can change a fair bit over the years.

- The service territory area ascribed to Hydro One is implausibly large. This could materially impact the estimate of the area (or Clearspring's density) variable parameter because Hydro One serves a large area and has been found in prior total cost benchmarking studies to be inefficient.
- Numbers of gas customers served were missing from the data for several sampled utilities, which were evidently not recognized as providers of gas services.
- The service territory area of Kansas City Power and Light was, in our view, also implausibly large.
- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for all sampled utilities, even though company-specific weights can be computed for Hydro Ottawa and the American IOUs in the sample and the labor cost share is typically well below 70% for these companies. Thus, the OM&A input price indexes for most distributors in the study were unnecessarily inaccurate.
- Clearspring used the U.S. gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for the Ontario utilities even though Hydro Ottawa proposes to use Canada's gross domestic product implicit price index for final domestic demand as a CPEF inflation measure. Clearspring used as the Ontario labor price trend a U.S. employment cost index x PPP when the Company proposes to use the average weekly earnings ("AWE") for Ontario as its other CPEF inflation measure.
- Pension and benefit expenses were included in the calculations even though the Company proposes a variance account for pension expenses in its Custom IR plan and pension expenses can be volatile and difficult to benchmark accurately.
- There is no control in the study for differences in the health care obligations of U.S. and Ontario utilities. While this is a source of possible bias *favoring* the Company, there are other sources of bias that cut the other way. Most notably, the peak loads of U.S. utilities

may be overstated. Also, Clearspring levelizes its labor and construction cost indexes using only data for headquarters cities. This likely overstates the price levels of many sampled U.S. utilities.

- 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's data were incorrectly mean-scaled.
- Clearspring removed *structure* maintenance expenses from the calculation when they should have removed the (typically larger) *streetlight* maintenance expenses.
- Clearspring's benchmarking of Hydro Ottawa's cost from 2021 to 2025 is problematic in several respects.
    - The formula used to escalate OM&A expenses was I – X rather than I - X + G.
    - The Company's latest forecast of capex was not used.
    - The Conference Board inflation forecasts used to benchmark Hydro Ottawa's future costs were dated (spring of 2019).

0% TFP Target

We also wish to challenge the notion that a 0% base productivity target is necessarily appropriate for Hydro Ottawa. Ontario data have many limitations for the accurate measurement of productivity trends. These include the recent benchmark year for capital cost calculations, the recent transition of many utilities to MIFRS accounting, and the fact that pension and benefit expenses are not readily excluded from such studies. The CPEF is designed to apply only to OM&A expenses. As well, Custom IR guidelines speak of an X factor that is as high or higher than that used in Price Cap IR.

PEG calculated the MFP trends of a large sample of U.S. power distributors in a recent study on multiyear rate plans for Berkeley Lab.[66] We reported TFP trends of 0.45% for the full 1980-2014 sample period and of 0.39% for the more recent 1996-2014 sample period. In recent testimony for the

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[66] Lowry, Makos, and Deason, *op. cit*., p. B.15.

Massachusetts Attorney General's office, PEG reported a TFP trend of 0.33% for a large sample of U.S. power distributors over the 21 years from 1997 to 2017.

Clearspring Reliability Benchmarking

We believe that Clearspring has, with the Company's sponsorship, done a service to Ontario's regulatory community by continuing to make progress in the area of reliability benchmarking. 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. Clearspring has gathered a respectable sample of publicly available U.S. data that span the years 2010-2017. Major event days have been excluded, if not with fully consistent definitions. The models presented by Clearspring are a good starting point for further improvements.

5. Alternative Research by PEG

5.1 Business Conditions Facing Hydro Ottawa

The external business conditions faced by Hydro Ottawa should be considered in the development of benchmarking models. The Company is an electric utility based in Ottawa and owned by the city. It provides power distributor services (e.g. distribution and customer services) but not power transmission or natural gas services. This limits its opportunities to realize scope economies. A subsidiary company, now called Portage Power, is engaged in small-scale renewable power generation in Ottawa and the surrounding region.

Power is distributed to most of the Ottawa-Gatineau metropolitan area.[67] In 2019, this area had a population of 1.44 million residents after years of brisk growth. The area includes Canada's national capital, two large universities, and a sizable information technology industry. Comparable North American metro areas include Edmonton ALTA, Salt Lake City, UT, Raleigh-Durham NC, and Oklahoma City. There are concentrations of office buildings in suburban Ottawa (e.g., Nepean, Gloucester, Kanata) as well as the downtown area where the capitol complex is located.

All customers now have AMI. The service territory includes a portion of the Rideau River and the Ottawa River valley but this produces little variation in the elevation of the service territory. Much of the surrounding region is forested.

Table 2 compares Hydro Ottawa's cost and external business conditions to the sample mean values in 2017. The following results are notable.

- Hydro Ottawa's cost was 32% of the sample mean.
- The Company's customer count was 34% of the mean while peak demand was 28%.

[67] The Company also serves the Village of Casselman Ontario. It does not serve the Quèbec side of the Ottawa River or some outlying areas of the city (e.g., Marlborough, Osgoode, and Huntley).

Table 2

Comparison of Hydro Ottawa's Business Conditions in 2017 to Full Sample Norms

Business Condition	Units	Hydro Ottawa Values, 2017 [A]	Sample Mean, 2017 [B]	Values / Sample Mean [A/B]
Total Cost($000 Dollars)	Dollars	217,373	675,817	0.32
Number of Retail Customers	Count	331,777	970,483	0.34
Rolling 5 Year Ratcheted Peak Demand	MW	1,430	5,082	0.28
Standard Deviation of Elevation		17	138	0.13
Percentage of Service Territory Forested	Percent	58.46%	57.27%	1.02
Percentage of Service Territory Congested Urban	Percent	0.12%	0.09%	1.23
Percentage of Customers with AMI meters	Percent	100.00%	43.58%	2.29
Percent of Total Customers that are Electric	Percent	100.00%	88.49%	1.13
Service Territory Area	Square Kilometers	1,116	28,019	0.04
Price Index for Capital Inputs	2017 Dollars	12.90	11.41	1.13
Price Index for O&M Inputs	2017 Dollars	1.47	1.16	1.27

- The share of the service territory that was congested urban and the share of customers with AMI were well above the mean.
- The company has no gas customers.
- The standard deviation of elevation was far below the mean.
- The share of the service territory forested was close to the mean.

5.2 Econometric Cost Research

Like Clearspring, we developed an econometric model of the total cost of power distributor base rate inputs. We also developed econometric models of two major components of total cost: OM&A expenses ("opex") and capital cost. Estimation results for all four models are reported in Tables 3-6. These tables include parameter estimates and their associated asymptotic t values and p-statistics. 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. A t test requires selection of a critical value for the asymptotic t ratio. We employed a critical value that is appropriate for a 75% confidence level.[68] In all of these 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.

Differences from the Clearspring Methodology

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

- Instead of a 2002 benchmark year to begin computation of Hydro Ottawa's capital cost we used 1989.[69]
- Instead of using only the Handy Whitman Index of Power Distribution Construction Costs in the Northeast US as the asset price deflator for Ontario distributors we assumed that the growth of the Ontario asset price index was a 50/50 average of the growth of this HWI and the growth of the ICSD for the Canadian utility sector.
- Instead of using the US GDPPI as the material and service price subindex for the Ontario distributors we used Canada's gross domestic product implicit price deflator for final domestic demand ("GDP-IPI").
- Instead of using the US employment cost index as the labor price trend index for the Ontario distributors we used the AWE of Ontario workers.
- The OM&A input price index used company specific cost share weights for Hydro Ottawa and the US distributors in the sample.[70] The cost share weights for the other Ontario distributors were fixed at 70/30.
- We assumed that Hydro Ottawa's OM&A expenses would grow at the same rate as their proposed CPEF, updated to reflect the latest inflation and customer forecasts.

[68] A one-tailed test was appropriate for most first order terms in the model. Two-tailed tests were appropriate for the quadratic and interaction terms associated with the scale variables.

[69] We did not have the time or budget to do this for the other Ontario utilities.

[70] For the U.S. utilities, these cost share weights were also time-varying.

- We treated the service territory area as a third scale variable where data supported this treatment and added quadratic and interaction terms.
- Instead of a stand-alone forestation variable we interacted the share of service territory forested with a variable measuring the share of distribution assets that were overhead.
- We corrected for missing data on the gas customers served by several sampled utilities and used a more accurate estimate of Hydro One's service area. We excluded the data for Kansas City Power and Light from the sample.
- We corrected the mean-scaling.
- We corrected the parameter estimates for first order autocorrelation using a standard method found in Stata, a popular econometric software package, in an effort to improve their precision. Statistical tests provided strong evidence of autocorrelation in the total cost and capital cost models.
- We did not use pre-2013 Ontario data in model estimation, except in the capital cost model.
- We benchmarked the opex and capital cost of Hydro Ottawa as well as its total cost.

Econometric Results

Econometric results for the total cost model are presented in Table 3. 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 but one 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.
- Total cost was also higher the higher was the share of the service territory that was urban, the share of distribution assets overhead x the share of service territory area forested, AMI penetration, the standard deviation of elevation, and the share of electric plus any gas customers that were electric.

Table 3

Econometric Model of Total Cost

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
A = Service territory area
PCTELEC = % electric customers
ELEVSTD = Elevation standard deviation
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTAMI = % of customers with AMI meters
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.655	16.61	0.000
N*N	0.531	6.89	0.000
D	0.282	7.20	0.000
D*D	0.600	5.74	0.000
D*N	-1.066	-6.35	0.000
A	0.068	6.20	0.000
A*A	0.026	4.66	0.000
A*N	0.011	0.52	0.606
A*D	-0.058	-2.80	0.005
PCTELEC	0.173	5.18	0.000
ELEVSTD	0.020	1.89	0.059
PCTOH*PCTFOREST	0.045	5.76	0.000
PCTCU	9.969	3.07	0.002
PCTAMI	0.018	1.10	0.274
Trend	-0.002	-1.15	0.250
Constant	13.130	238.12	0.000

Adjusted R^2 0.997

Sample Period 2002-2017

Number of Observations 1302

Pacific Economics Group Research, LLC

- The estimate of the trend variable parameter suggests that cost was falling by about 0.2% annually for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.997. This suggests that the model had a high level of explanatory power.

OM&A Expenses

Results for the opex cost model are presented in Table 4. Please note the following.

- The parameter estimates for the number of customers and ratcheted peak demand were both significant and positive.[71] Notice that the number of customers had a much greater impact 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 area variable and its related second-order terms did not have sufficiently strong statistical support to warrant inclusion in the model.
- The parameter estimates for the additional quadratic and interaction terms associated with the two included 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 the service territory that was congested and urban. A quadratic urban congestion variable was added and its parameter estimate was also highly significant.
- Opex was also higher the higher was system overheading, share overhead x share forestation, and the standard deviation of elevation.
- The trend variable parameter estimate indicates a 0.7% annual decline in opex for reasons other than changes in the values of included business condition variables. This decline is considerably more rapid than that in the total cost model.

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

Table 4

Econometric Model of OM&A Expenses

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
ELEVSTD = Elevation standard deviation
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTPOH = % of plant overhead
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.883	11.94	0.000
N*N	0.609	3.96	0.000
D	0.106	1.38	0.167
D*D	0.467	2.31	0.021
D*N	-1.026	-3.10	0.000
ELEVSTD	0.051	3.03	0.002
PCTOH*PCTFOREST	0.057	4.38	0.000
PCTCU	86.017	4.85	0.000
PCTCU*PCTCU	-2295.294	-3.70	0.000
PCTPOH	1.388	7.05	0.000
Trend	-0.007	-2.62	0.009
Constant	10.792	57.42	0.000

Adjusted R^2	0.981
Sample Period	2002-2017
Number of Observations	1305

- Table 4 also reports a 0.981% adjusted R^2 statistic for the opex model. This is just a little below that for the total cost and capital cost models.

Capital Cost

Econometric results for the capital cost model are presented in Table 5. Here are some key results.

- The parameter estimates for the number of customers, ratcheted peak demand, and the area variable were all highly significant and positive. All but one of the parameter estimates for the extra quadratic and interaction terms for the output variables were also highly significant. This suggests that the relationship of capital cost to the three output variables is significantly nonlinear.
- Capital cost was also higher the greater was the share of the area served that was congested and urban, share forestation x share overhead, AMI penetration, and the ratio of electric customers to the sum of gas and electric customers.
- The estimate of the trend variable parameter indicates a 0.2% annual increase in capital cost for reasons other than changes in the values of the model's business condition variables.
- The 0.998 value of the adjusted R^2 model was very similar to that for the total cost model.

Table 5

Econometric Model of Capital Cost

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
A = Service territory area
PCTELEC = % electric customers
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTAMI = % of customers with AMI meters
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.702	32.96	0.000
N*N	0.332	6.94	0.000
D	0.229	10.83	0.000
D*D	0.325	5.31	0.000
D*N	-0.596	-6.11	0.000
A	0.100	12.76	0.000
A*A	0.023	5.49	0.000
A*N	-0.028	-1.95	0.051
A*D	-0.014	-1.28	0.202
PCTELEC	0.170	5.73	0.000
PCTOH*PCTFOREST	0.024	3.63	0.000
PCTCU	11.665	3.87	0.000
PCTAMI	0.023	3.30	0.001
Trend	0.002	2.48	0.013
Constant	10.476	797.10	0.000

Adjusted R^2	0.998
Sample Period	2002-2017
Number of Observations	1351

5.3 Econometric Benchmarking Results

We benchmarked the opex, capital cost, and total cost of Hydro Ottawa in each year of the historical 2013-2018 period as well as in the 2019-2025 period for which the Company has provided proposals/projections. For the capital cost model we were also able to benchmark the 2006-2012 period because we have less concern about the inconsistency of pre-MIFRS data. 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 6-8 and Figures 1-3 report results of this benchmarking work. For each cost considered, we provide results for each year as well as average results for the last three historical years (2016-2018) and the five years of the proposed new Custom IR plan (2021-25).[72]

Table 6 and Figure 1 show results of our econometric *total* cost benchmarking. It can be seen that the company's total cost was about 13% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. Cost efficiency will decline modestly during the Company's current IR plan but is projected to stabilize during the next plan after a drop in 2021. On average, projected/proposed total cost during the new plan will exceed the benchmarks by 5.0% during the 2021-25 term of the Custom IR plan.

Table 7 and Figure 2 show results of our econometric opex benchmarking. It can be seen that Hydro Ottawa's total cost was a considerable 18% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. OM&A efficiency will decline modestly during the Company's current IR plan but is projected to stabilize during the next plan. On average, projected/proposed total cost during the new plan will be 0.5% below the benchmarks during the 2021-25 Custom IR term. This would essentially be an average cost performance.

[72] Recollecting the recent benchmark years for estimating capital cost in Ontario, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Table 6

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2013	-13.3%
2014	-9.3%
2015	-6.0%
2016	-5.6%
2017	-5.6%
2018	-2.2%
2019	*3.3%*
2020	*2.3%*
2021	*4.9%*
2022	*5.8%*
2023	*5.0%*
2024	*4.4%*
2025	*5.0%*
Annual Averages	
2013-2018	**-7.0%**
2016-2018	**-4.5%**
2021-2025	**5.0%**

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

Note: Italicized numbers are projections/proposals.

Figure 1

Hydro Ottawa's Total Cost Benchmarking Scores

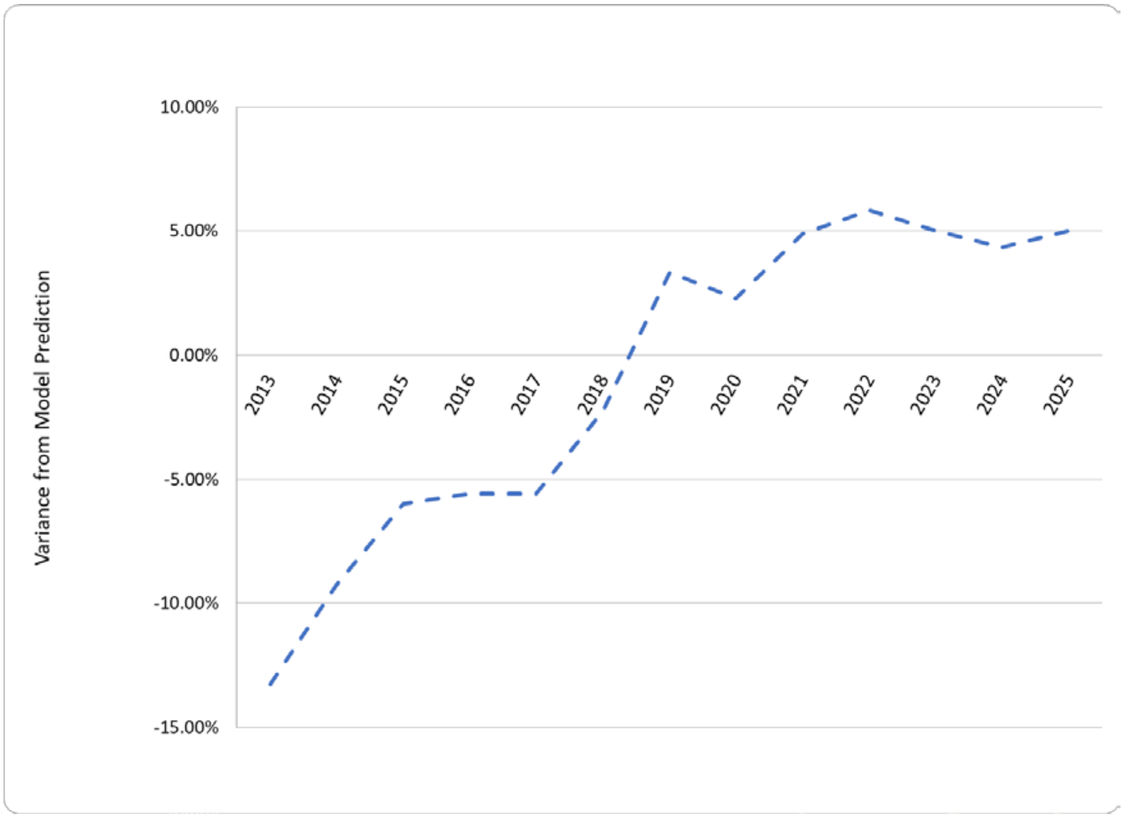


Table 7

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2013	-18.2%
2014	-11.3%
2015	-5.9%
2016	-7.2%
2017	-9.1%
2018	-0.5%
2019	*0.1%*
2020	*-1.6%*
2021	*-0.9%*
2022	*-0.8%*
2023	*-0.6%*
2024	*-0.3%*
2025	*0.0%*
Annual Averages	
2013-2018	**-8.7%**
2016-2018	**-5.6%**
2021-2025	**-0.5%**

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

Note: Italicized numbers are projections/proposals.

Figure 2

Hydro Ottawa's OM&A Cost Benchmarking Scores

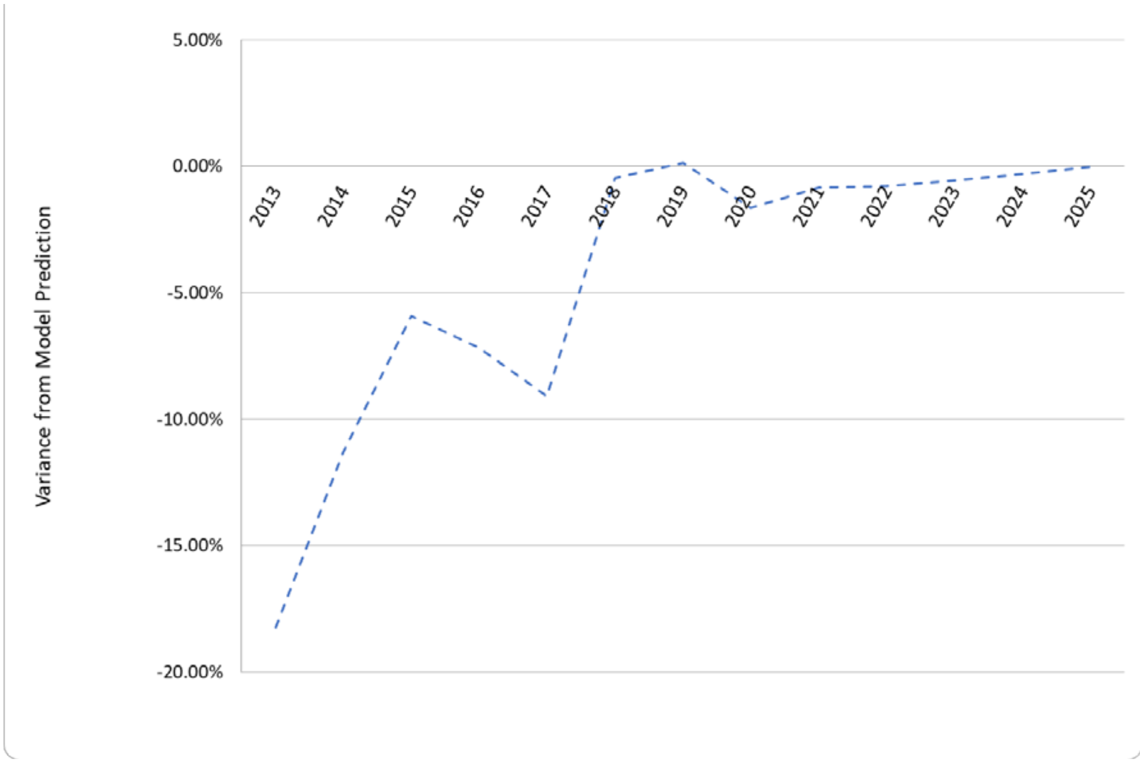


Table 8 and Figure 3 show results of our econometric *capital* cost benchmarking. It can be seen that Hydro Ottawa's capital cost was about 6% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. Capital cost performance will decline considerably during the Company's current IR plan but is projected to stabilize during the next plan after a decline in 2021. On average, projected/proposed total cost during the new plan will be 12.2% above the benchmarks for the 2021-25 period.

Table 8

Year by Year Capital Cost Benchmarking Results

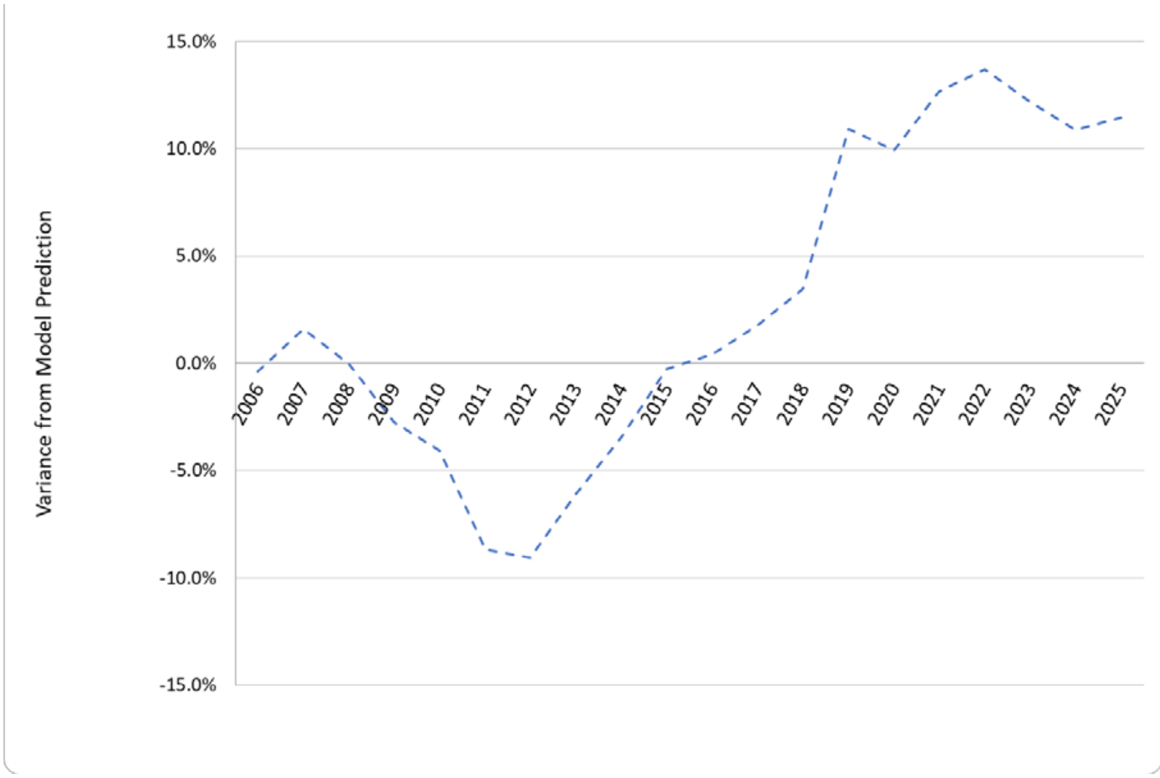
Year	Percent Difference[1]
2006	-0.4%
2007	1.6%
2008	0.0%
2009	-2.8%
2010	-4.1%
2011	-8.7%
2012	-9.1%
2013	-6.1%
2014	-3.4%
2015	-0.3%
2016	0.4%
2017	1.8%
2018	3.5%
2019	*10.9%*
2020	*9.9%*
2021	*12.7%*
2022	*13.7%*
2023	*12.2%*
2024	*10.9%*
2025	*11.4%*
Annual Averages	
2006-2018	**-2.1%**
2016-2018	**1.9%**
2021-2025	**12.2%**

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

Note: Italicized numbers are projections/proposals.

Figure 3

Hydro Ottawa's Capital Cost Benchmarking Scores



5.4 Stretch Factor

The stretch factor should be based on the total cost of Hydro Ottawa's base rate inputs. The cost of the two major capex projects that the Company has taken should not be excluded. Major plant additions may to some degree be driven by external business conditions but they are also to some degree optional (especially with regard to timing). New construction has the disadvantage of tying up funds in the ownership of assets that are especially valuable because they will last for many years. The geometric decay approach to measuring capital cost that PEG and Clearspring both use in benchmarking captures this disadvantage. Utilities are thereby incentivized to postpone plant additions until they are really needed. Analogous exclusions were not made for the costs of other companies in the sample.

Hydro Ottawa's 5.0% average total cost benchmarking score over the 2021-25 sample period would be commensurate with a 0.30% stretch factor under Price Cap IR conventions. On the basis of our research, we believe that a 0.30% stretch factor is indicated for Hydro Ottawa. We recommend this stretch factor if the Board is comfortable fixing the stretch factor for the full plan term.

5.5 Base Productivity Trend

Hydro One's proposed CPEF would apply only to the Company's OM&A revenue. Should the Board wish to adopt this approach, the question of an appropriate productivity growth target arises. As we noted in Section 2 above, the OEB states in the Rate Handbook that

> 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.[73]

In recent testimony for the Massachusetts AGO, PEG found that the OM&A productivity growth of a large sample of U.S. power distributors averaged 0.39% over the eleven year 2007-2017 sample period. The number of customers was the sole output variable in this calculation.

Early RRF guidelines called for Custom IR ARMs to reflect "the Board's inflation and productivity analyses." OEB Staff has asked PEG, as part of the engagement, to calculate the OM&A productivity trend of U.S. utilities for this proceeding. Pursuant to this request, we calculated the trend in the OM&A productivity of U.S. distributors in the Clearspring sample. The sample consisted of all of the U.S. distributors included in the sample that had good data for all years of the sample period. Florida Power & Light was excluded due to the recognition in 2017 of a large amount of deferred storm damage cost, which resulted in an atypical end point that cannot be relied upon for a trend analysis. We also added Kansas City Power & Light to the sample, as its area data problem did not affect the OM&A PFP calculations.

In this exercise, output growth was an elasticity-weighted average of the growth in customers and ratcheted peak demand. OM&A input quantity growth was calculated as the difference between the growth in OM&A expenses and an OM&A input price index we developed using company-specific and time-varying cost share weights for labor and other OM&A inputs.

Results of this exercise can be found in Table 9. It can be seen that, over the full 2007-2017 sample period considered, the OM&A productivity of the sampled U.S. distributors averaged 0.27%. The scale index averaged 0.51% growth while OM&A input quantity growth averaged 0.24%.

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[73] *Rate Handbook*., pp. 25-26.

Table 9

US Power Distributor OM&A Productivity Trend[1]

(Growth Rates)

Year	Scale Index	O&M Input Quantity Index	O&M Productivity Index
2007	1.03%	6.35%	-5.32%
2008	0.57%	-1.59%	2.16%
2009	0.24%	-1.43%	1.67%
2010	0.33%	0.89%	-0.57%
2011	0.20%	2.30%	-2.11%
2012	0.27%	-0.59%	0.86%
2013	0.42%	-6.51%	6.94%
2014	0.49%	4.83%	-4.34%
2015	0.69%	-3.85%	4.54%
2016	0.78%	3.77%	-2.99%
2017	0.62%	-1.48%	2.10%
Average Annual Growth Rate 2007-2017	**0.51%**	**0.24%**	**0.27%**

[1]All growth rates are calculated logarthmically.

Scale Escalator

We showed in Section 3 of the report 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 for a utility that will be experiencing brisk growth in scale. The output growth of Hydro Ottawa in the next four years is clouded by the current pandemic challenge, but has traditionally been brisk. We accordingly support the proposed customer growth escalator.

Fixed vs. Variable CPEF

Given the uncertainty that the COVID-19 pandemic has triggered surrounding inflation and customer growth in the next five years, we recommend that the OEB not approve a fixed CPEF for Hydro

Ottawa. The ability to adjust revenue growth to changing business conditions without weakening utility incentives is one of the chief advantages of indexed attrition relief mechanisms.

CPEF Summary

If the CPEF applies only to OM&A revenue, as proposed by Hydro Ottawa, our recommended CPEF formula is Inflation – 0.57% + G where the X factor is the sum of a 0.27% base OM&A productivity trend and a 0.3% stretch factor. If CPEF applies to *all* revenue (i.e., OM&A and capital) in a rate adjustment formula similar to what the OEB has approved for Hydro One and Toronto Hydro in 2019 decisions, we recommend a 0.30% X factor consisting of 0% base TFP trend and a 0.3% stretch factor.[74]

[74] EB-2017-0049, March 7, 2019 for Hydro One distribution and EB-2018-0165, December 19, 2019 for Toronto Hydro.

6. Other Plan Design Issues

The other provisions of the Custom IR plan proposed by Hydro Ottawa are in some respects uncontroversial. We have noted that the plan is similar to the expiring one, which was detailed in a Board-approved settlement. There are some customer protections since an ESM would asymmetrically share only surplus earnings and the capital variance account would asymmetrically return capital revenue requirement savings to customers. We are nonetheless concerned about some other features of the Company's proposal.

6.1 Capital Cost Concerns

Basic Concerns

The ratemaking treatment of capital is our chief concern about the other plan provisions. We begin by acknowledging that utilities operating under indexed ARMs based on industry cost (e.g., price and productivity) trends sometimes do need extra capital revenue. We noted in Section 3 that productivity growth drivers vary between utilities and, for individual utilities, over time. Some kinds of capex are lumpy and capex, once incurred, raises costs recoverable from customers based on in-service asset values, for many years. Index research used to design ARMs may, furthermore, fail to properly capture utility cost trends.[75] MRPs with ARMs based on cost trends have, for these and other reasons, had provisions for supplemental capital revenue in Ontario and several other jurisdictions (e.g., Alberta, British Columbia, and Hawaii).

The fairness of supplemental revenue provisions is magnified if the subject utility has either not previously operated under MRPs or *has* operated under such plans but prior ARMs were under-compensatory. On a net present value basis, *under*-compensation in the early years of operation under MRPs will tend to outweigh any possible *over*-compensation in future years. MRPs with under-compensatory ARMs would, under these circumstances, tend to be unfair to the utility as well as increasing its risk and the cost of accessing funds in capital markets.

[75] The research might, for example, not capture the cost impact of repex which utilities experience.

While extra capex funding is sometimes needed, provisions for such supplements can nevertheless be controversial and greatly complicate MRP design and execution. Legitimate concerns can arise as to capex containment incentives, over-compensation, and regulatory cost. All of these concerns arise with Hydro Ottawa's proposed plan.

Weak Incentives

Under Hydro Ottawa's plan, growth in its capital revenue requirement would be based on a projection/proposal of its total capital cost. This projection would, if approved, be fully funded without even a stretch factor markdown. The entirety of any cumulative revenue requirement reduction that occurred due to capex *under*spends would be returned to ratepayers. The ongoing annual capital cost of the depreciated balance of any capex *over*spends could possibly be added to required revenue in future rebasings. The Company could also recover, through the Z factor (or similar mechanisms), the entirety of material capex incurred due to some unforeseen external events. Capital revenue would thus be determined on a largely cost of service basis while OM&A revenue would be indexed.

These provisions would greatly reduce Hydro Ottawa's capex containment incentive.[76] There would, for instance, be an incentive to spend too much on capital that reduces OM&A business expenses.[77] The Company's capital cost has grown rapidly under the provisions of its current Custom IR plan, which is its first. For example, the Company has undertaken a "once in a generation" building project and plans another big project during its next plan for 2021-2025. On balance, this approach to Custom IR has such weak incentive power that it may not seriously merit an IR characterization.

Despite the proposed claw back of all capital cost savings, Hydro Ottawa would still have some incentive to exaggerate its capex needs since exaggerations strengthen the case for Custom IR, which affords the Company extra revenue and preapproval of capex budgets and reduces pressure to contain

[76] It is important to emphasize that the pass-through of all capital cost savings is the chief, though not the only, incentive problem with Hydro Ottawa's proposal.

[77] There is, for example, an extra incentive to underground lines. The tendency for over-capitalization is a well-known issue referred to as the Averch-Johnson effect. See Averch, Harvey and Leland L. Johnson (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. 52 (5): 1052–1069

capex and the risk that too little was requested.[78] Hydro Ottawa would also still have some incentive to "bunch" deferrable capex, in this and similar future plans, in ways that bolster extra revenue.[79] If, for example, the Company could change, after 2025, the timing of its capex so that $I - X + G$ escalation of its first-year revenue requirement was compensatory throughout the plan it would not qualify for extra revenue. There is also a temptation to change the mix of capex projects during the plan so that there remain some projects that justify continuation of Custom IR. Continual operation under Custom IR has joined the bunching of capex around the rebasing year as a serious concern.

Overcompensation

An overcompensation problem arises if a utility receives more funding than it needs for a given capex surge. Overfunding may occur during a plan and/or over multiple plans. Hydro Ottawa's proposed plan raises several overfunding concerns.

Consider first that most of the capex that occasions supplemental revenue is similar in kind to that incurred by distributors sampled in productivity studies used to set X factors. For example, distributors occasionally build, replace, or substantially expand transformer stations and office buildings. To the extent that this capex slows their productivity growth, the X factor will be lower and ARMs will have grown faster in previous IR plans, the current plan, and future plans. The OEB has been setting base TFP trends at 0% for several years, and the capex of Ontario distributors has doubtless reduced provincial TFP growth. Hydro Ottawa can then be compensated twice for some of the same capex: once via full funding of its projected/proposed capital budget and then again by low X factors in past, present, and future IR plans.

A related overcompensation concern is that, while customers would be asked to fully compensate Hydro Ottawa when its capital cost growth is *brisk* for reasons beyond its control, the Company can in the future switch to Price Cap IR and avoid commensurately reducing its capital revenue

[78] Exaggeration of capex needs may reduce the credibility of Hydro Ottawa's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted.

[79] While an incentive to bunch would exist, the optimal bunching strategy for Hydro One is not obvious since spreading out high capex creates a rationale for continuing Custom IR.

if capital cost growth is unusually *slow* for reasons beyond its control.[80] Slow capital cost growth in the future could very well occur for reasons other than good management. For example, depreciation of recent and prospective surge capex like that for the South Nepean MTS will tend to slow the Company's capital cost growth in the future as its net plant value gradually depreciates. The Company acknowledged in response to an interrogatory[81] that "accumulated depreciation reduces the rate base and capital cost growth. Given the same amount of capital spending, all else equal, when the rate base starts at a higher level the capital cost growth will be lower." To the extent that capex has been bunched during Custom IR, there may be less need for it afterwards. While a capex surge and the resultant short-term productivity slowdown and revenue shortfall are easily discerned, productivity growth that modestly exceeds the peer group norm which may precede or follow the surge is likely to be attributed to good management.

Under Hydro Ottawa's proposal, customers therefore would never receive the full benefit of the industry's TFP trend, even in the long run and even when it is achievable.[82] The Company would, by the same token, manage to skirt the challenge of having to match industry TFP growth in the long run in order to achieve the target rate of return between rate cases. These problems illustrate how hard it is to design good IR plans when the premise is accepted that expected revenue shortfalls in one plan should be fully funded without consideration of previous and subsequent plans.

Note also that no consideration has been paid, in the Company's past or current plan, to any special *advantages* Hydro Ottawa has in managing its costs. These advantages have included in the past, and may in the future continue to include, comparatively brisk customer growth that increases opportunities to realize scale economies. The Board's 0% base productivity trend applies to all Ontario utilities and is effectively an industry standard.

[80] If the Company embraced the Annual IR Index option, the X factor would be higher.

[81] Hydro Ottawa Interrogatory Response to OEB-34 a).

[82] It is possible, of course, that a utility could experience an inordinately large number of (or inordinately large) unfavorable events that make it difficult to achieve the MFP trend of the peer group in the short run or long run. For example, a distributor directly hit by a hurricane may deserve supplemental compensation even though few utilities in the productivity sample used to calibrate X have been similarly afflicted. A utility ordered to replace all wooden poles with cement poles could, similarly, argue that this has rarely been asked of peer group utilities. However, the degree to which peer group productivity trends reflect various kinds of unfavorable events is difficult to assess.

Still another overcompensation concern is that, due to the specific hybrid design of the revenue cap, the stretch factor term in the CPEF would apply only to the Hydro Ottawa's OM&A revenue. This is less than half of the Company's total revenue requirement.[83]

High Regulatory Cost

Hydro Ottawa's weak incentive to contain capex and its incentives to exaggerate its capex needs and strategically manage capex in order to bolster extra revenue all give stakeholders and the Board extra reasons to scrutinize the Company's multiyear capex proposal. Careful oversight of capex plans raises regulatory cost and has proven increasingly taxing to the OEB and stakeholders as most of Ontario's larger utilities queue up for Custom IR. Regulatory cost is an important consideration in Ontario, which has large gas and electric utility industries and an unusually large number of power distributors to regulate.[84] Containment of regulatory cost is part of the rationale for using indexed ARMs and statistical benchmarking in Ontario. The Board has used the regulatory cost argument to rationalize materiality thresholds to limit use of Z factors, ACMs, and ICMs.

Despite the extra effort, the OEB and stakeholders naturally struggle with the difficult task of effectively reviewing distributor capex proposals for multiyear plans. In essence, the Board has sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements but has not made investments that British and Australian regulators have in the capability for appraising multiyear capex proposals. Both of these regulators have, for example, commissioned statistical benchmarking and engineering models to produce independent estimates of capex needs. The British regulator Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IR proceedings.[85] Ofgem has also devised a complicated Information Quality Incentive to encourage truthful cost forecasts. Ofgem also has spent considerable sums on engineering consultants.

[83] We noted in Section 5.5 above the additional concern that the X factor in the CPEF formula would be based on total factor productivity growth.

[84] It should also be noted that the analogous regulators in American states do not have primary jurisdiction over power transmission rates and services.

[85] Ofgem (2014), RIIO-ED1: *Final determinations for the slow-track electricity distribution companies Overview Final Decision*, November 28, p. 22.

Excessive Use of Custom IR

It is also notable that the full funding of its capital cost growth which Hydro Ottawa proposes is more remunerative than that available under Price Cap IR. We noted in Section 2.2 that ACMs and ICMs feature a materiality threshold with a meaningful dead band before projected capital revenue shortfalls are funded.[86] The disparity in expected returns encourages distributors to choose Custom IR instead of Price Cap IR or an Annual IR Index. Some distributors may now or in the future choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though efficient and compensatory operation under Price Cap IR or an Annual IR Index is feasible.

Conformance with Board Policy

Partly for the reasons just discussed, the proposed plan does not conform well to the Board's policies and recent decisions concerning Custom IR. We noted in Section 2 that Hydro Ottawa's prior plan was approved before the Board issued its *Rate Handbook* in 2016. The Handbook states that

> Custom IR is not a multi-year cost of service; explicit financial incentives for continued 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).[87]

Only the proposed ratemaking treatment of OM&A expenses satisfies these guidelines, and these expenses account for less than half of the Company's revenue requirement. Hence, the proposed plan is conformant with the Handbook only if these guidelines are construed as not necessarily intended to apply to most of an applicant's costs.

Alberta Experience

Other regulators have sought to balance a need to make IR reasonably compensatory with the high regulatory cost and weak cost containment incentives that can result from such efforts. This has

[86] The Board rationalized these thresholds chiefly (and in the cast of Z factors entirely) on the grounds of reducing regulatory cost even though they make sense for other reasons.

[87] *Rate Handbook*, *op. cit.*, p. 25.

sparked periodic reconsideration of IR and new IR approaches. The RIIO approach to regulation in Great Britain is one such outcome.

In this section we discuss the deliberations of the Alberta Utilities Commission ("AUC"). The AUC has, in generic proceedings, developed two generations of MRPs for large gas and electric power distributors. In each generation of plans, rates or (for gas distributors) revenue per customer have been escalated by I-X formulas designed using evidence on industry cost trends. In both proceedings, jurisdictional distributors claimed an outsized need for capex due in part to the "boom and bust" nature of Alberta's economy. This led to provisions for extra capex funding in both generations of MRPs. The AUC has addressed many of the issues that the OEB has grappled with.[88]

In the first-generation plans supplemental funding was provided, via "capital trackers," for *individual categories* of capital cost if an "accounting test" convincingly demonstrated that the funding otherwise provided by the ARM was insufficient. The resultant percentage adjustments to rates were called "K factors." All benefits of capex underspends were passed back to customers. A great deal of capex proved to be tracker-eligible. A further generic proceeding was required just to clarify tracker policy. Regulatory cost was high and incentives to contain capex were weak.

The AUC stated the following about its experience with this plan.

> The Commission considers that **finding a mechanism that achieves the balance between providing incremental funding for capital while maintaining the incentives to improve productivity and lower costs inherent in the PBR plans, without double-counting, has been challenging during the first PBR term**… many highly complex issues involving the interpretation and application of the capital tracker criteria, including grouping issues, the establishment of the accounting test to determine the amount of funding available under I-X, and project assessment to confirm the need for a project, have arisen in the various capital tracker proceedings. The number and complexity of these issues far outstrip any other issues that have arisen from the implementation of the PBR plans.
>
> Accordingly, **the Commission considers that it is reasonable to consider whether modifications to, or substitutes for, the capital tracker mechanism can be made in the next generation PBR plans to improve regulatory efficiency** while achieving the balance of objectives identified in Decision 2012-237. **These modifications could include**, as

[88] For example, The AUC stated in D-2012-237 that "A capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting." (p. 115).

> suggested by AltaGas, **streamlining options**, particularly for multi-year capital tracker programs.[89] **[Emphasis added]**

The mentions of regulatory efficiency and streamlining are notable given the Board's stated concerns with Custom IR.

Conclusions

The OEB has evinced mounting frustration with the cumbersome Custom IR option that most large Ontario utilities now request. It is notable that high regulatory cost has been a major concern since this was not emphasized in the OEB's Custom IR guideline discussions. 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 distributors. Custom IR should be streamlined and/or used less frequently. 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.

6.2 Alternative Ratemaking Treatments for Capital

Absent a comprehensive generic proceeding to reconsider the RRF, we have, with a limited budget aligned with aims of our work in reviewing Hydro Ottawa's Custom IR proposal in this application, extended the analysis of possible reforms to the ratemaking treatment of capital which we have provided in some other recent Custom IR proceedings. We believe that the following alternatives to Hydro Ottawa's proposed ratemaking treatment of capital merit consideration by the Board and other parties to this proceeding. We group the alternatives into: 1) smaller reforms that are evolutionary in character; and 2) more sweeping changes to Custom IR. All of the options should be appraised for their ability to strengthen utility performance incentives, reduce regulatory cost, and ensure customers a reasonable share of IR benefits.

[89] Alberta Utilities Commission Final Issues List in Alberta Utilities Commission Proceeding 20414, August 21, 2015, p. 9.

Smaller Reforms

C Factor and S Factor

The most obvious alternative to Hydro Ottawa's proposal is that approved by the OEB in recent Custom IR decisions for THESL and Hydro One.[90] The CPEF would nominally apply to capital as well as OM&A revenue. A C factor would be added to the CPEF formula which escalates revenue for a portion of any positive difference between the approved growth in the Company's total capital cost and the capital revenue growth that the CPEF would otherwise provide. The capital cost growth eligible for recovery would be reduced by the TFP growth target, the stretch factor, and a supplemental stretch factor (aka S factor) for capital. This is, effectively, a materiality threshold that includes a dead band.

The capital revenue requirement in the first indexing year can be represented formulaically as

$$RK_1 = \{CK_o \times [1 + [I - (TFP + Stretch) + G)]\} + \{CK_1 - CK_0 \times [1 + (I + G) + S]\} \quad [7a]$$

$$= CK_o \times [1 + (I + G)] - CK_o \times (TFP + Stretch) + CK_1 - CK_0 \times (1 + G) - CK_0 \times S \quad [7b]$$

$$= CK_1 - (TFP + Stretch + S) \times CK_0. \quad [7c]$$

where

RK = allowed capital revenue

CK_t = capital revenue requirement in year t

I = growth in the inflation measure

TFP = base TFP trend

Stretch = stretch factor

G = growth factor

Compared to Hydro Ottawa's proposal, this approach would strengthen capex containment incentives, reduce overcompensation concerns, and conform better with the OEB's Custom IR Guidelines with only a small increase in regulatory cost.[91] Since a portion of *capital cost growth* would be ineligible for funding, a portion of the *capex* (which utilities control during the plan) would also be

[90] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019 and *Decision and Rate Order*, EB-2018-0165, February 20, 2020.

[91] The chief incremental regulatory cost is deciding on the S factor.

ineligible. The stretch factor would apply to capital as well as to OM&A revenue. This approach also has the merit of not binding future Board panels that must approve new regulatory systems.

On the other hand, gains from this approach would be modest at the low values for X and S which the OEB has recently approved. Incentives and the likelihood that a capex plan would be ineligible for Custom IR depend on the base TFP trend, which the Board has for several years been setting at zero. There would not be a meaningful materiality threshold for Custom IR even though the arguments for such a threshold apply to Custom IR just as they do to ACMs, ICMs, and Z factors.

It should also be noted that the THESL and Hydro One plans are compliant more with the letter than with the spirit of the Board's Custom IR guidelines.[92] When the base TFP trend is set at zero, such plans are particularly close to violating the *Rate Handbook* standard that "it is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications." The incremental capital stretch factor of 0.15% barely achieves compliance. As noted in Section 2.4, the Board indicated in its recent THESL decision a lack of enthusiasm for considering additional plans with these features.

The benefits from the C factor approach would be increased were the S factor raised substantially from the 0.15% level recently approved for Hydro One Transmission. A higher S merits contemplation for several reasons.

- An S of 0.15% is unlikely to establish parity with the ACM and ICM capex markdowns.
- The OEB has rationalized materiality thresholds (and, in the case of the ACM and ICM, dead bands) chiefly on the grounds of reducing regulatory cost. Yet we have noted two other rationales for markdowns: stronger capex containment incentives and lessened overcompensation concerns.
- The markdown in the ACM and ICM materiality thresholds is actually far less than 10%.

[92] This approach conforms to the Board's Custom IR guidelines in the Rate Handbook in the same sense that a restaurant offers a lobster dinner if it offers a dinner featuring lobster plus a chef's special "menu surprise," where the surprise is that 60% of the lobster is replaced with poor man's lobster in the form of previously-frozen haddock.

- A higher markdown could, over time, materially reduce the number of capex plans eligible for Custom IR. It could particularly discourage continuation of Custom IR when utilities are approaching the end of a period of high capex.
- A higher S conforms to the OEB's guideline that, for a Custom IR plan, X be higher than and certainly no lower than what it would be under Price Cap IR.

Utilities may respond to a higher markdown by asserting a need for higher capex and/or bunching more capex to attain eligibility. To the extent that a higher markdown is rationalized on the grounds of overcompensation in *future* IR plans, it should be noted that the future of IR in Ontario is unclear. MRPs with indexed ARMs based on industry cost trends may not continue. Higher markdowns therefore makes more sense to the extent that the Board is confident that regulation will continue to be broadly similar.

Also on the downside, the Board stated in the Rate Handbook that Custom IR did not involve a "threshold test." However, the Board's approved C factor approaches have effectively involved thresholds.[93] Regulatory cost would still be high and capex containment incentives would still be weak.

If the Board chooses the C factor approach for Hydro Ottawa, we believe that the S factor should be at least high enough that, together with the TFP target, it achieves parity with the capex markdowns in the ACM and ICM formulas. We further encourage the Board to consider an even higher S factor that is more likely to materially reduce the number of eligible Custom IR applications.

Variants on the C Factor Theme

Variants on the current C factor approach to Custom IR also merit consideration. One variant would be to calculate C using the (typically slower) productivity growth trend of capital, while the X factor for OM&A revenue would reflect the (typically faster) productivity trend of OM&A. This would modestly reduce the size of C factors and, combined with a meaningful materiality threshold, reduce the frequency of Custom IR plans. Escalation of OM&A revenue would better reflect industry OM&A cost

[93] The AUC, in its first generation PBR decision, approved a 40 basis point *cumulative* materiality threshold on projects eligible for tracking. A 4 basis point threshold was applied to individual projects. AUC Decision 2013-435, p. 86.

trends. There is precedent for separate indexing of O&M and capital revenue in British Columbia IR.[94] Unfortunately, there is no contestable recent research available to the panel in this proceeding on the capital productivity trends of power distributors.

Consider next that one reason why incentives are weak under the current C factor approach is that utilities have no incentive to contain their *incremental* capex once capital cost growth exceeds the threshold. The following alternative mechanism would provide an incentive to contain incremental capex.

$$RK_1 = CK_0 \times \{1 + [(I - (TFP + Stretch) + G)]\} - \{[CK_1 \times (1\text{-}S)] - CK_0 \times [1 + (I\text{+}G)]\} \quad [8a]$$

$$= CK_1 - (S \times CK_1 + (TFP + Stretch) \times CK_0). \quad [8b]$$

An alternative approach with more complicated math would also accomplish this

$$RK_1 = CK_0 \times \{1 + [(I - (TFP + Stretch) + G)]\}$$
$$- \{CK_1 - CK_0 \times [1 + (I - (TFP + Stretch) + G)]\} \times (1\text{-}S) \quad [9]$$

Formula [8b] would not establish a materiality threshold. Desirable attributes of both approaches could be combined by using [7c] to establish the materiality threshold and then using [8b] to determine the exact amount of eligible capital cost. In other words, if proposed capital cost exceeded the materiality threshold, a percentage of *all* (or a wider range of) unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capex at the margin.

Consider next that, under the current mechanism, the choice of the S factor is tied to the base productivity trend. The appropriate value of S would likely be higher if X is 0% (or -0.3%) than if it is 0.3%. This complication in choosing S can be sidestepped by making the capital cost eligible for extra revenue independent of the base productivity trend. This can be achieved by the following formula.

$$RK_1 = CK_o \times \{1 + [I - (TFP + Stretch) + G]\}$$
$$+ \{[CK_1 - CK_0 \times [1 + (I - TFP + G) + S)]\} \quad [10a]$$
$$= CK_o \times [1 + (I\text{-}TFP\text{+}G)] - CK_o \times Stretch + CK_1 - CK_0 \times [1 + (I\text{-}TFP\text{+}G)] - CK_0 \times S \quad [10b]$$
$$= CK_1 - (Stretch + S) \times CK_0. \quad [10c]$$

[94] See, for example, the recent plans of FortisBC (formerly West Kootenay Power) and FortisBC Energy (formerly Terasen Gas). Note that the base productivity trends have been the same for OM&A and capital revenue.

Consider finally that it is difficult to calculate a value for S that establishes parity with the markdown that ACMs and ICMs require. A straightforward way to sidestep this calculation is to abandon the current C factor mechanism entirely and to instead use the current ACM/ICM mechanism to determine the capex eligible for supplemental revenue. Alternatively, the ACM/ICM mechanism might be used to determine incremental capex eligible for supplemental revenue, which would then be used to determine the C-factor for the rate adjustment in each year. This might require some adjustments to the C factor formula to maintain parity with the ACM/ICM.

Alternative Eligibility Restrictions

Eligibility of capex for supplemental revenue could be scaled back by the alternative method of making certain *kinds* of capex ineligible. Some capex would then be addressed by the CPEF. Here are some possible exclusion criteria.

- Some approved MRPs with indexed ARMs based on cost trends permit variance account treatment only for plant additions that are major and/or unpredictably timed. The FRP and South Nepean MTS projects of Hydro Ottawa would likely qualify. This approach is featured in the recently expired MRPs of FortisBC and FortisBC Energy.[95] An example from Hawaii is discussed below.
- While distributors serving rapid-growth regions experience growth-related cost bumps, growth-related capex could be deemed ineligible for supplemental revenue (or certain *kinds* of supplements) on several grounds.[96] For example, a lot of growth-related capex is partially self-

[95] British Columbia Utilities Commission ("BCUC") (2014), *In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, pp. 170-175.

BCUC (2014), *In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, pp. 176-181.

[96] The AUC stated in Decision 2012-237 that one of its capital tracker eligibility criteria

> excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth, and also through contributions in aid of construction.

However, in a later decision it revised this criterion. Capex eligible for tracker treatment must also exceed a materiality threshold. The Commission described its eligibility requirements as having a "targeted criteria-based financed by growth in billing determinants and contributions in aid of construction. Some kinds of growth-related capex (e.g., costs incurred due to construction of mass transit and highway infrastructure) are potentially eligible for Z factoring. Intensive use of CDM and distributed generation and power storage can reduce the need for substation and substransmission system capacity expansions.[97] Consider also that distributors in rapid-growth regions tend to have outsized opportunities to realize scale economies. Our research over the years has revealed that such distributors often experience rapid MFP growth.

- Capex in the last year of the plan term could be deemed ineligible for extra revenue because this involves only one year of underfunding.

This general approach would strengthen capex containment incentives and reduce overcompensation concerns despite a net *reduction* in regulatory cost. The freedom of OEB panels in future proceedings would not be fettered. On the other hand, to the extent that such eligibility restrictions are rationalized on the grounds of overcompensation in future IR plans, it should again be noted that the future of IR in Ontario is unclear. This approach therefore makes more sense to the extent that the Board is confident that regulation using ARMs based on industry cost trends will continue.

<u>X Factor Adjustment</u>

The X factor could be raised, in this and any future IR plans, by an amount sufficient to increase the likelihood that revenue cap indexes reflect industry productivity growth over multiple plans. This could be accomplished in several ways.

- One approach would be to recompute TFP growth removing a certain share of the capex made by sampled utilities. In a study for a British Columbia proceeding, PEG reported that, over the ten year 2002-2011 period, removing 10% of gross plant additions from the study increased the

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nature" that "limits the number of projects that are outside the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible." (September 2012, pages 124 and 127).

[97] Encouragement of such non-wire alternatives ("NWAs") to load-related capex is a focus of IR today in some American states (e.g., New York). See, for example, the Brooklyn-Queens demand management project of Consolidated Edison of New York.

average annual TFP growth of a large sample of U.S. power distributors by 25 basis points.[98] A downside of this particular approach is that it is difficult to establish what share of capex should be removed from the productivity study. There is no contestable evidence on this matter in this proceeding.

- Another approach would be to require utilities seeking supplemental funding to borrow revenue escalation privileges from future plans. If, for example, customers were in one plan effectively asked to fund capital productivity growth that was 3.2% above the industry norm on average over the indexing years of a plan, the X factor could be SK x 0.4% or roughly 0.2% higher in this and the next 7 plans to make customers whole. Here SK would be the typical share of capital cost in total utility cost.

Several benefits of this general approach of adjusting the X-factor are notable. Overcompensation concerns would be reduced. The incremental regulatory cost is small. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro Ottawa's capex containment incentives. X factor adjustments would continue only if a broadly similar form of IR with an indexed ARM based on industry cost trends was used in future plans.

One downside of this general approach is that the freedom of future Board panels may be fettered, or they may choose not to honor past commitments. If future growth in the ARM is slowed by this means, the utility is more likely to request supplemental capital revenue in future plans via Custom IR, ACMs, or ICMs.[99] However, this problem could be mitigated by having higher Custom IR, ACM, and ICM materiality thresholds.

Continued Tracking

Capital costs that occasion supplemental revenue could be subject to continued variance account treatment in later plans. Customers, having fully funded the initial cost of surge capex, would then receive the benefit of its depreciation between rate cases in later plans. This would reduce

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[98] Lowry, M.N., Hovde, D.A., and Rebane, K. (2014), *X Factor Research for Fortis PBR Plans*, Submitted on behalf of Commercial Energy Consumers Association of British Columbia in British Columbia Utilities Commission Projects 3698715 and 3698719, January 7, pp. 35-37.

[99] This concern would, however, be lessened by a meaningful materiality threshold.

overcompensation concerns. The utility's revenue for surge capex would closely track the annual cost of the investment that the Board deemed prudent. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro Ottawa's capex containment incentives. Tracking need continue only if a broadly-similar form of IR with an indexed ARM based on cost trend research continued.

On the downside, the regulatory burden of continuing to track the revenue requirement for old capex would be non-negligible. However, the recent MRPs for the Fortis companies in BC tracked the cost of *all* older capital.[100] The freedom of future regulators may be abridged and they may choose not to abide by the arrangement (e.g., they may instead role surge capex into the rate base addressed by the indexed ARM and not continue to track its cost).

A portion of depreciating older plant would be excluded from the cost that is addressed by the ARM in Price Cap IR or its successor. This would increase the likelihood that Hydro Ottawa would in the future claim a need for supplemental revenue in the form of an ACMs, ICMs, or Custom IR. However, this problem could be mitigated by having meaningful Custom IR, ACM, and ICM materiality thresholds.

Incentivized Variance Account

The capital variance account is the single leading cause of the weak capex containment incentives in Hydro Ottawa's proposed plan. In Ontario, these accounts were initially approved in proceedings where the ability of utilities to spend the high levels of capex which they proposed was questioned.[101] The ability of Ontario utilities to markedly increase their capex has been since been amply demonstrated.

One way to incentivize the capital variance account would be to permit Hydro Ottawa to keep a share of the revenue requirement impact of capex underspends.[102] The Company could, for example, be permitted to keep the revenue requirement impact resulting from the first X% of savings, as in the Hydro One Custom IR plans.

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[100] These expiring plans indexed only the revenue requirements for OM&A expenses and routine capex.

[101] See, for example, Ontario Energy Board EB-2014-0140.

[102] A share of any revenue requirement overruns could, in principle, be deemed ineligible for rate basing.

This general approach would strengthen Hydro Ottawa's incentive to contain capex with little increase in regulatory cost. The freedom of future Boards would not be compromised. However, a reduction in overcompensation is not ensured since this approach would reduce customer clawbacks of underspends and increase the Company's incentive to exaggerate its capex needs.[103] Moreover, gains would be small under the sharing provisions that the OEB has thus far approved. Regulatory cost would still be high, capex containment incentives would still be weak, and even a plan with a C factor would still be compliant more with the letter than the spirit of the Board's guidelines.[104] The benefits from this approach would be increased were the Company's share of revenue requirement savings raised substantially. At the extreme, the plan could contain no capital cost variance account, like a previous Enbridge Gas Distribution plan.[105]

An exemption of underspends due to productivity gains also strengthens incentives to underspend but encourages strategic behavior by the utility. For example, the Company has an incentive to misrepresent the extent of true productivity gains and to hold back on productivity gains in its initial revenue requirement offer. Regulatory cost would be increased materially**.**

A third approach meriting consideration is to place a hard cap on the capital revenue requirement. The undepreciated balance of investment resulting from a capex overspend would then be ineligible for inclusion in rates in later rebasings. Alternatively, only a share of the overspend capex could be declared eligible.

Variants of the approaches to capital variance account incentivization used thus far in Ontario merit consideration. The dead band could be eliminated, or a range could be established where variances are shared. For example, customers could be permitted to keep the entirety of the first 10% of cumulative revenue requirement savings and 50% of any additional savings.

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[103] The AUC stated in its first generic PBR decision 2012-237 that "The use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs…to be a major drawback to such an approach." p. 131.

[104] This approach conforms to the Board's Custom IR guidelines in the same sense that a restaurant offers a lobster dinner if it offers a dinner featuring lobster plus a chef's special "menu surprise" where the surprise is that 2/3 of the lobster is replaced with previously-frozen haddock.

[105] EB-2012-0459, *Decision with Reasons*, July 14, 2014.

Precedents for incentivized trackers in the regulation of other utilities shed light on their potential merit and possible designs. PEG has not undertaken a comprehensive survey of approved cost tracker sharing provisions but we are aware of several examples. Most notably, this type of mechanism has been approved for capex in California, Britain, and British Columbia.

Details of some approved capital tracker sharing mechanisms can be found in Table 10 below. Please note the following.

- The BCUC has approved Certificates of Public Convenience and Necessity for several large capex projects that were conditional on a mechanistic sharing of cost variances. Some of these mechanisms shared cost overruns or underspends that were outside of a +/- 10% band evenly between the utility's shareholders and customers. Notice that in the cited BC plans *customers* kept the entirety of the first 10% of variances.

- In the United States, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas obtained special ratemaking treatments to recover the cost of full AMI deployment. These treatments combined a preapproved multiyear capex forecast with a cost tracker. Recovery was allowed for capital costs net of OM&A savings. If each company's actual cost to deploy AMI was in line with the approved forecast, there would be no subsequent prudence review.

  Southern California Edison's AMI deployment tracker featured an asymmetric sharing mechanism wherein 90% of the first $100 million in excess of the approved forecast was absorbed by shareholders and 10% by customers without the need for a further prudence review. Exceptions to the cost caps were made for *force majeure* events, changes in the project's scope due to government or regulatory activity, and delays in Commission approval. The treatment of variances from forecasted cost for San Diego Gas & Electric was similar, as 90% of the first $50 million over the budget would be absorbed by shareholders without a further prudence review. San Diego Gas & Electric's AMI tracker also authorized a sharing of the first $50 million under the budget, with 10% going to the company. Southern California Gas' AMI tracker was similar to San Diego Gas & Electric's. The company would absorb 50% of the first $100 million above the budget and keep 10% of the first $100 million under the budget without a further prudence review.

Table 10

Details of Incentivized Capital Cost Trackers

Jurisdiction	Company Name	Services	Eligible Investments	Special Treatment of Cost Variances	Case Reference
BC	Terasen Gas (now FortisBC Energy)	Gas	Customer Care Enhancement Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Order C-1-10
BC	Terasen Gas Vancouver Island (now FortisBC Energy)	Gas	Gas pipeline lateral from Squamish to Whistler	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Orders G-53-06, G-76-06
BC	Terasen Gas Whistler (now FortisBC Energy)	Gas	Conversion of Whistler Gas system from propane to methane, meter/regulating station	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order G-53-06
BC	BC Gas (now FortisBC Energy)	Gas	Southern Crossing Pipeline Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk.	Order G-51-99
BC	FortisBC	Bundled power service	Big White Supply Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order C-17-06
CA	San Diego Gas & Electric	Power and Gas Distribution	Advanced metering infrastructure ("AMI")	No deadband. Asymmetrical mechanism wherein 90% of the first $50 million over the cap and 10% of first $50 million under the cap allocated to shareholders (No prudence review required)	Decision 07-04-043 (April 2007)
CA	Southern California Edison	Power Distribution	Deployment of AMI	No deadband. Asymmetrical Mechanism wherein 90% of first $100 million over the cap charged to customers (No prudence review required)	Decision 08-09-039 (September 2008)
CA	Southern California Gas	Gas	AMI	Overrun sharing mechanism: Up to $50 million to be paid by shareholders, calculated as 50% of first $100 million over total cost; Underrun sharing mechanism: Up to $10 million to be received by shareholders, calculated as 10% of first $100 million under total cost.	Decision 10-04-027 (April 2010)

- In Britain, energy utility revenue requirements are based on total (capital and operating) expenditures (aka "totex"). Utilities may share in both underspends and overspends of totex relative to approved amounts. The utility's share of totex variances is tied mechanistically to how reasonable the utility's expenditure forecast is deemed to be by Ofgem. This provision is part of Ofgem's complicated information quality incentive mechanism.

Incentivized cost trackers have also been approved in North America for energy (e.g., generation fuel) procurement costs and for other operating revenues. It should also be noted that many multiyear rate plans have been approved over the years in which utilities keep the benefits of *all* capex underspends or share them only through an ESM.

Custom IR Limits

Accumulating experience with Custom IR in Ontario (and analogous mechanisms elsewhere) suggests that it would be desirable to limit its usage. In addition to making its terms less favorable to utilities, the OEB should consider limiting the frequency with which utilities can use Custom IR. For example, the option could be made available in only three of each five (or two of each three) IR cycles. This would strengthen capex containment incentives and could substantially lower regulatory cost if utilities would otherwise likely opt for Custom IR continually.

However, utilities would be more likely under this restriction to bunch capex so that it occurs in years when Custom IR plans are permissible. Utilities denied the right to use Custom IR could make aggressive use of ACM, ICM, and Z factor provisions of Price Cap IR. This would increase the importance of DSP reviews. The freedom of future Board members could be abridged or they may refuse to abide by the arrangement.

Strengthen Reviews of Capex Prudence

The OEB should encourage greater effort to review capex prudence. Performance incentives can be strengthened thereby and overcompensation reduced. The Board has already taken a big step in this direction by requiring DSPs and learning how to review them. One the other hand, regulators will still struggle with the asymmetry of information.

Further upgrades to the prudence review process merit consideration. Engineering and econometric models could be commissioned to ascertain the need for repex, and variants on Ofgem's information quality incentive mechanism could be developed. Plans can be reviewed over periods longer than five years for their tendency to bunch capex in ways that bolster supplemental capital revenue. Inefficient bunching of capex should be discouraged, but so too should be strategies that unduly prolong Custom IR. Plans in the late stages of a capex surge merit special scrutiny. Excessive use of capex to reduce OM&A expenses is another special concern. For example, proposals to increase system undergrounding merit special scrutiny.

On the downside, conscientious reviews of capex are costly. The OEB will still operate at an information disadvantage. Thus, a mix of prudence reviews and IR mechanism will continue to be optimal.

Major Departures

The Board may also wish to consider more substantial departures from the capital cost treatments it has approved in prior Custom IR proceedings. The following alternative ratemaking treatments of capital in Alberta and California then merit consideration.

Alberta and California

California The California Public Utilities Commission ("CPUC") has required jurisdictional gas and electric utilities to operate under MRPs since the 1980s. Revenue decoupling has been common, so these plans have typically featured *revenue* caps, not *price* caps. Escalation of these caps between rate cases has often involved hybrid mechanisms with separate treatments of OM&A and capital revenue.[106] OM&A revenue has typically been indexed for inflation. The capital revenue requirement is calculated, using traditional cost accounting, under the assumption that a utility's gross plant additions in each year of the plan will equal its recent historical average or the approved test year additions. The Office of the

[106] *See, e.g.*, the current multiyear rate plan of Southern California Edison as approved in CPUC Decision 19-05-020.

Ratepayer Advocate has often expressed a reluctance to consider multiyear capex forecasts.[107] Gross plant additions are sometimes adjusted for inflation in later years of the plan.

These plans typically have not included capital variance accounts that returned benefits of most capex underspends to customers. Earnings sharing mechanisms have also been uncommon.

Hybrid revenue caps in California have sometimes been combined with capital cost trackers that are limited in scope but address major plant additions with hard to predict timing (e.g., AMI and generation facilities). Under a hybrid ARM, it is easier to ensure that capital costs are not double counted should the need for a capital cost tracker arise, as parties can identify whether or not the costs associated with a project are already addressed through the capital cost budget.

Alberta The second-generation Alberta MRPs[108] allow for two methods by which distributors may obtain extra capex funding. Trackers may fund material capex that is required by a third party or extraordinary. Supplemental funding for other kinds of capex is provided by the "K-bar." A base K-bar value was established for each distributor for the first year of the plan based on its recent *historical* capex, adjusted for growth in inflation, X, and billing determinant growth, which were not funded by base rates. [109] This process is repeated for subsequent years. These plans do not include ESMs or trackers that return the benefits of capital underspends to customers.

Appraisal The California and Alberta approaches to ARM design have notable selling points. Regulators need not sign off in advance on the prudence of detailed multiyear capex plans. There is less opportunity for utilities to exaggerate their capex needs. This can reduce regulatory cost considerably. Capex containment incentives are strengthened by the lack of an ESM or capex underspend clawback

[107] It may be noted that these are large distributors, three of which serve over six million customers, and this has helped to stabilize capex requirements. A very large distributor might, for example, build or replace three substations every five years whereas a small Ontario distributor might build or replace one substation every forty years.

[108] PEG is not recommending this ratemaking treatment for Hydro Ottawa.

[109] For power distributors the change in billing determinants is calculated across all billing determinants including energy, demand, and the number of customers, while the billing determinants for gas distributors is calculated as the weighted average change in the number of customers among rate classes.

and by increased uncertainty about capex prudence reviews in the next rebasing.[110] Overcompensation is reduced if OM&A revenue escalation is not based on TFP trends. Other overcompensation concerns would remain, however, in an application to Ontario since Hydro Ottawa could return to Price Cap IR in a future plan.

On the other hand, this approach requires confidence that recent capex levels will continue during the plan term. DSPs are still needed to provide this confidence. It is possible that a utility's capex needs will change during the plan due to unforeseen circumstances such as a deep recession. Some OEB Custom IR guidelines are violated since the capital revenue requirement is unaffected by the industry productivity trend or stretch factor. However, the Board could modify the California approach in order to incorporate its rate-setting principles and policies as documented in the Rate Handbook.

Capex containment incentives can be weakened if this approach continues in future plans and the capital revenue requirement in these plans is again expected to be based on recent historical capex. For example, Hydro Ottawa's incentives would be weakened during its new plan if there was an expectation that its capex in the 2021-2025 period was going to be used to set the capex budget for the next plan. Research by PEG for Berkeley Lab found that the TFP growth of California distributors has been slower and not more rapid than the sample norm during their years of operation under MRPs.[111] In the case of Hydro Ottawa, this problem can be mitigated by using the same base capex levels in any third Custom IR plan. However, it seems doubtful that this strategy would be reasonable for more than one additional plan. An argument could be made for extending the new plan to seven years with an understanding that a return to Price Cap IR would follow.

Some parties may be concerned that this approach invites the utility to defer capex without sharing benefits and then argue that another high capex budget is needed in the next plan. An ESM or incentivized capital variance account can share benefits. Alternatively, any revenue requirement reduction from capex underspends can be reserved to fund future capex subject to the understanding

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[110] The AUC stated in its first generic PBR decision (D-2012-237) that "The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker, p. 131.

[111] Lowry, Makos, Deason, *op. cit*., pp. 6.11-6.13.

that elevated capex budgets will not long be permitted. For example, Hydro Ottawa could be instructed that it is eligible for only one additional consecutive Custom IR plan.

The California approach to ARM design may seem to be inconsistent with some OEB Custom IR guidelines. However, a capital cost projection that is based on an annual budget for gross plant additions that is fixed in nominal or real terms can be used to make C factor calculations.

Econometric MFP Projections

In Hawaii, a generic proceeding is underway to develop a new performance-based regulation ("PBR") framework for the Hawaiian Electric Companies ("HECO") and two affiliates. These three vertically integrated electric utilities ("VIEUs") are chiefly engaged in T&D since most power in Hawaii is generated by third parties or customers. Like many Alberta and Ontario distributors, the HECO companies claim a need for high levels of repex.[112]

The Commission has decided that the new PBR framework will feature MRPs with revenue cap indexes that have I – X formulas designed using cost trend research.[113] Each plan will also have a major plant interim recovery cost tracker. Repex will, importantly, *not* be eligible for tracker treatment. The X factor thus has special importance in this proceeding. The challenge has been to use research on the cost trends of mainland VIEUs to determine an X factor that is suitable for the costs to which the revenue cap index will apply, which include considerable repex.

PEG has performed an econometric study funded by the HECO companies to identify drivers of mainland VIEU productivity growth and quantify their impact. A T&D "repex requirement indicator" that we developed was found in the study to be a highly significant VIEU cost driver. This indicator is based on past capex patterns using data on gross plant additions back to 1948.

PEG developed from this research an econometric MFP growth projection for the next five years which is specific to the business conditions that HECO expects to face in managing the costs that its revenue cap index will address. These projections are, essentially, an estimate of the MFP growth that typical utility managers would achieve in managing these costs. The projections take account of the fact

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[112] The repex surge in the islands is occasioned by the surge in capex in the years following Hawaiian statehood.

[113] These plans will feature revenue decoupling.

that HECO will experience sluggish electric customer growth and a growing need for repex but the costs subject to indexing will not include those for any AMI buildout, new emissions controls, gas customer growth, or generation plant additions which mainland VIEUs have experienced. The projections provide the basis for an X factor that is customized to HECO's business conditions but doesn't weaken its incentive for capex containment.

This productivity research was based on a methodology pioneered by Denny, Fuss, and Waverman.[114] PEG first used econometric MFP growth projections in work for the OEB in a gas IR proceeding.[115] An article on this research was published in the *Review of Network Economics.*[116]

This kind of research could in principle be used to establish an X factor for Hydro Ottawa or other Ontario distributors. Econometric research on power distributor cost could consider the impact of productivity growth drivers such as customer growth, AMI, and the need for repex. This research could provide the basis for an econometric MFP growth projection for Hydro Ottawa during the four indexing years that is specific to the business conditions the Company is expected to face during these years. This could be the company's base TFP growth trend. Alternatively, X could be based on the industry productivity trend and the MFP growth projection could provide the basis for a CPEF adjustment like the C factor.

The potential advantages of this approach are numerous. Compensation could be provided for special capex challenges without weakening Hydro Ottawa's performance incentives. The Company would have less opportunity to exaggerate its capex needs.

On the downside, the research required to establish the method would be somewhat costly and controversial. The contracted budget for our engagement by OEB staff in this proceeding, and the schedule for the proceeding, did not allow for such research in this project. The MFP projection would reflect the typical impact of system *age* on cost when the OEB has encouraged distributors to base repex

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

[115] Lowry, M.N., Hovde, D., Getachew, L., and Fenrick, S. (2007), *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*, Report to the Ontario Energy Board filed in Ontario Energy Board Cases EB-2007-0606 and EB-2007-0615, November 20, pp. 41-49.

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

on system *performance*. However, this is not different in spirit from basing the base TFP trend on an industry study and then adding a stretch factor which reflects the stronger performance incentives generated by IR.

The X factor would likely be based on research using U.S. data and would likely be negative. However, the stretch factor would ensure that customers receive the benefit of productivity growth that is superior to the projection.

Sensible Pairings

Several of the rate setting options detailed in this Section are complements more than substitutes. Here are some provisions that could be sensibly combined.

- A California or Alberta-style ARM, which reflects a utility's recent past capex, reduces concerns about the utility's exaggerations of its capex requirements. This can increase the attractiveness of incentivizing or eliminating the capital variance account.
- A California or Alberta-style ARM could also be combined with a limit on the frequency of Custom IR plans.
- An MFP growth projection that considers the need for repex can be combined with a tracker to fund lumpy growth-related projects like the South Nepean MTS, the need for which is more difficult to identify econometrically due to data limitations.
- If the C factor approach is adopted without major modification, it could be combined with other mechanisms that strengthen incentives (e.g., capital variance account incentivization), reduce overcompensation (e.g., continued tracking), and reduce regulatory cost (e.g., Custom IR limits).
- Using Custom IR more frequently than three out of every five plans could be tied to a requirement that any surplus capital revenue be offset by future X factor reductions if the use of ARMs based on industry cost trends continues.

Appendix

A.1 U.S. vs. Canadian Data for Power Distributor Cost Benchmarking

Accurate statistical benchmarking is facilitated by abundant, high quality data on utility operations. In this section we discuss the relative advantages of U.S. and Ontario data for statistical benchmarking of Ontario power distributors.

Pros and Cons of Ontario Data

About seventy utilities provide power distribution services in Ontario today. These utilities also provide a wide range of customer services that include conservation and demand management ("CDM"). The distribution systems of some companies include subtransmission lines and substations that receive power at subtransmission or higher voltages. The largest provincial distributor, Hydro One Networks, also provides most power transmission services in Ontario.

Advantages of using data for other Ontario utilities to appraise the cost performance of Hydro Ottawa include the following.

- Standardized, high quality data are publicly and electronically available on operations of numerous Ontario distributors for more than a decade. Thus, a large sample is available for econometric estimation of cost model parameters. Large samples of good data improve the accuracy of econometric model parameter estimates.
- Data are available for all distributors on peak loads and the total length of distribution lines (in circuit km).
- There is no need for currency conversions in an Ontario benchmarking study, and adjustments are fairly straightforward if desired for differences between input prices in various parts of the province.

Disadvantages of Ontario data include the following.

- Many of the distributors serve small towns outside the larger metropolitan areas and hence face business conditions quite different than those of Hydro Ottawa.

- Many distributors recently transitioned to Modified International Financial Reporting Standards ("MIFRS"). These new standards reduced capitalization of OM&A expenses for many companies and thereby raised reported OM&A expenses.
- Itemized data on pension and benefit expenses of most Ontario distributors, including Hydro Ottawa, are unavailable for lengthy sample periods. These costs are difficult to benchmark accurately, and the Company proposes to address pension expenses with a variance account rather than indexing. Canadian labor price indexes are available only for salaries and wages and not for comprehensive employment costs
- Data needed to calculate capital costs and quantities for most distributors using monetary methods are available only since 1989.[117] In addition, data on *gross* plant additions, which we normally use to calculate capital costs, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross (undepreciated) value of plant. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available. Statistics Canada suspended calculation of its electric utility construction price indexes several years ago. These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.
- Itemization of OM&A salary and wage and material and service expenses is not readily available for a lengthy sample period.

Pros and Cons of U.S. Data

Power distributor services in the United States are provided to most customers by investor-owned utilities ("IOUs") but are provided in some areas by cooperative or municipal utilities.[118] U.S. distributors typically provide several customer services (e.g., metering, meter reading, billing, and

[117] We believe that it is straightforward to interpolate plant additions over the few years for which gross plant value data are available before the year 2000.

[118] Cities that are served by municipal utilities include Austin, Los Angeles, Memphis, Nashville, Sacramento, and Seattle.

collection) but varied levels of CDM services.[119] Most IOUs also provide power transmission services in their service territory and many provide generation and/or gas utility services.[120] The distribution systems of some companies include subtransmission lines and substations that receive power at transmission voltages.

American IOU operating data have several advantages in a Hydro Ottawa total cost benchmarking study.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of IOUs.
- Distributors provide an array of services that is similar to Hydro Ottawa's.
- Several IOUs serve medium-sized metropolitan areas.
- U.S. cost data are credibly itemized, permitting calculations of the cost of power distributor services even for vertically integrated utilities ("VIEUs").
- Data on the net value of plant and the corresponding gross plant additions have been itemized for power distribution and general assets since 1964. Custom price indexes are available on the construction cost trends of power distributors. These advantages make U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power distributors.
- Urbanization, operating scale, and other business conditions vary widely amongst IOUs and this facilitates their identification and quantification of their impact.

There are, however, some downsides to using U.S. IOU operating data in distributor cost research.

[119] CDM services in some states are provided by independent agencies.

[120] Examples of vertically integrated electric utilities ("VIEUs") include Duke Energy Carolinas, Florida Power and Light, Georgia Power, and Northern States Power.

- Good data on distribution line length, a potentially useful scale variable, are not publicly available for most major IOUs.[121]

- Peak load is another potentially relevant scale variable in a power distribution cost study. Available U.S. peak load data include sales for resale, and these sales are material for some VIEUs. In order to use these data in a distribution cost study it is necessary to adjust them and these adjustments will typically not be exact.

- Itemized data are available on administrative and general expenses and the value of general plant but these are driven by the entirety of each IOU's operations and not just by the provision of distributor services. If these costs are to be considered in the research, it is necessary to assign a portion of them to distributor services by some arbitrary means.

Mixing Ontario and U.S. Data

The appropriate mix of Ontario and U.S. data to use in a study to benchmark the costs of an Ontario distributor is difficult to ascertain. Since Hydro Ottawa did not provide us with all of the data we need in order to remove pension and other benefit expenses from its costs, we have decided to include the data from all seven Ontario distributors that are included in the Clearspring sample for the econometric research.

A.2 Measuring Capital Cost

Monetary Approaches to Capital Cost Measurement

Monetary approaches to the measurement of capital costs and prices have been widely used in statistical cost research. These approaches decompose capital cost into consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \cdot Quantity^{Capital}. \qquad [A1]$$

In utility cost studies, the capital prices are usually calculated using data on utility construction costs and the rate of return on capital. The capital price index is sometimes a "rental" or "service" price index, so

[121] Some data on *overhead* pole (aka structure or route) miles are available for a considerably larger group of companies from surveys of an American data vendor.

called since, in a competitive rental market, the price of rentals would tend to reflect the cost incurred to supply a unit of capital services (e.g., the use of an automobile for one week).

Several monetary methods to measuring capital cost are well established. A key issue in the choice between these methods is whether utility plant is valued in historic or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from each year's gross plant additions. Decay can result from many factors including wear and tear, casualty losses (e.g., ice storms), increased maintenance requirements, reduced reliability, and obsolescence.

Three monetary methods have been used in statistical research on utility costs.

- The geometric decay ("GD") specification features a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay in the quantity of capital resulting from each year's gross plant additions. A utility's cost is therefore fairly sensitive to the age of its assets and TFP growth is comparatively sensitive to high levels of repex. Assets are valued in replacement dollars. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

  Academic research has supported use of the GD method to characterize depreciation in many industries. [122] GD has been the most widely-used method by far in North American X factor studies. PEG has used the GD method in most of its productivity and benchmarking work for the Board.

  The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[123] However, the U.S. Bureau of Labor Statistics uses the alternative

[122] See, for example, C. Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right," University of Maryland working paper, 2008.

[123] The BEA states on p. 2 its November 2018 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

hyperbolic decay specification in its studies of the productivity trends of the US economy and its major sectors.

- The one hoss shay ("OHS") capital cost specification assumes that the quantity of capital from each year's gross plant additions does not decay gradually but, rather, all at once as the assets reach the end of their service lives and are replaced. Plant is once again valued at replacement cost and a capital service price is used. With this specification, a utility's capital cost is comparatively insensitive to the age of its system and TFP growth is comparatively insensitive to high levels of repex. The one hoss shay method has been used occasionally in X factor and benchmarking research.
- The cost of service ("COS") specification is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historical valuation of plant. A utility's capital cost is unusually sensitive to the age of its system and TFP growth is unusually sensitive to high levels of repex. The capital price and quantity formulas are complicated, making them more difficult to code and review. PEG has used this approach in several X factor studies, including two for the OEB.[124]
- Hyperbolic Decay ("HD"). HD is an alternative monetary capital cost specification that merits consideration in utility cost trend and cost performance studies. The service flow from groups of assets considered is assumed to decline at a rate that may increase as assets age. Like OHS and GD, an HD specification typically assumes a replacement valuation of plant. Cost is net of capital gains. The capital price is a service price which reflects these assumptions.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely

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[124] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment 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 earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and to estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex 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 cost 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.

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