Evaluation of Hydro Ottawa's Proposed Custom Incentive Regulation Framework

for The Ontario Energy Board

By

Nick Crowley
Dan McLeod, PhD
Xueting (Sherry) Wang, PhD

October 14, 2025

Table of Contents

Evaluation of Hydro Ottawa's Proposed
Custom Incentive Regulation Framework

for

The Ontario Energy Board

by

Christensen Associates Energy Consulting

October 14, 2025

1. INTRODUCTION

1.1 Qualifications

1. Christensen Associates Energy Consulting, LLC ("CA Energy Consulting"), a wholly owned subsidiary of Laurits R. Christensen Associates, Inc., provides utility industry stakeholders with expert support on economic issues ranging from rate design, cost of service, cost of capital, and performance-based regulation ("PBR"). In recent years, the firm has undertaken substantial project work assisting utilities and regulators in both the United States and Canada with evaluating and designing incentive regulation frameworks. The company has a long history of work in this field, having been involved in developing the theoretical foundations and practical design of incentive regulation plans dating back to the inception of incentive regulation in North America in the 1980s.

2. This report is authored by CA Energy Consulting experts with substantial experience on issues related to incentive regulation. Mr. Nicholas Crowley is a Vice President. He has testified on incentive regulation issues in Massachusetts, New Hampshire, and Alberta, and has authored public and non-public research reports in Ontario,[1] Indiana, Maine, and other jurisdictions. He has also conducted research related to incentive regulation, with articles published in the journal *Utilities Policy* and *The Electricity Journal.* Prior to joining CA Energy Consulting, Mr. Crowley was an economist in the Office of Energy Market Regulation at the United States Federal Energy Regulatory Commission ("FERC"), where he assisted with industry benchmarking, the price cap regulation of oil pipelines, and the review and evaluation of natural gas pipeline rate cases. He holds a Bachelor of Science degree in economics, as well as a Master of Science degree in economics from the University of

[1] "Jurisdictional Review of Utility Remuneration Models," *CA Energy Consulting,* September 2024, https://engagewithus.oeb.ca/advancing_pbr.

Wisconsin-Madison. He is also a CFA charterholder and holds the Certified Rate of Return Analyst designation. Mr. Crowley's resume is attached as Appendix 2.

3. In rate proceedings involving PBR, Dr. Daniel McLeod has sponsored testimony, performed industry productivity and cost benchmarking analyses, and co-authored a report that examined the appropriate financial remedy following a reopener. He has also co-authored research reports on PBR. He holds a PhD in economics from the University of Wisconsin-Madison, where he graduated with a focus in industrial organization and applied econometrics. Dr. McLeod's resume is attached as Appendix 3.

4. Dr. Xueting(Sherry) Wang has co-authored public and non-public research reports in Ontario, Maine, and Massachusetts related to incentive regulation. She has assessed the incentive properties of alternative, customized PBR frameworks as applied to electric distribution utilities. She holds a PhD in sustainable development from Columbia University specializing in energy economics and a Master of Public Policy degree from the National University of Singapore. Dr. Wang's resume is attached as Appendix 4.

1.2 Purpose of the report

5. CA Energy Consulting has been asked by the Ontario Energy Board staff ("OEB staff") to provide an independent evaluation of the PBR framework filed by Hydro Ottawa Limited ("Hydro Ottawa", or "the Company") under docket EB-2024-0115. This work has involved reviewing materials filed before the Ontario Energy Board ("OEB") pertaining to Hydro Ottawa's Custom Incentive Regulation ("Custom IR") plan, including a review of the initial application, the Company's responses to interrogatories, and the transcript of the Technical Conference. This report contains our independent evaluation of Hydro Ottawa's Custom IR plan proposal and offers recommendations for certain elements of the framework.

6. The report is organized as follows. After this introduction, Section 2 evaluates the productivity component of Hydro Ottawa's proposed X factor. Section 3 assesses Hydro Ottawa's modified benchmarking analysis and stretch factor. Section 4 provides an analysis of the proposed growth factor. Section 5 reviews the Company's proposed Earnings Sharing Mechanism ("ESM"), and Section 6 examines the Company's proposed variance accounts. Each of these sections contain recommendations following our analysis. The final section concludes with a summary of our recommendations.

7. We acknowledge that we have a duty to provide opinion evidence to the OEB that is fair, objective, and non-partisan.

2. PRODUCTIVITY FACTOR

2.1 Productivity Factor Background

8. Hydro Ottawa has filed a Custom IR framework that consists of a revenue cap on operations, maintenance, and administration (OM&A)-related revenue. The X factor is a central component of a properly calibrated revenue cap. In Ontario, the X factor consists of two components: (1) industry productivity growth; and (2) a stretch factor. This section addresses the industry productivity component of the X factor.

9. Revenue cap regulatory frameworks annually adjust prices or revenues based on a formula of factors largely beyond the control of the company.[2] This formula sets either prices or revenues such that the utility's costs and allowed revenues are temporarily de-linked. The formula consists of an inflation factor (I) less industry productivity growth (X) plus a growth factor (G). The formula is derived from a fundamental economic principle of market competition, which states that over the long run, the costs and revenues of a firm are equal in a perfectly competitive market. Appendix 1 presents this derivation.

10. The X factor for a revenue cap that adjusts a company's total allowed revenue—i.e., both operating-related revenue and capital-related revenue—relies on an empirical measure of sector-specific total factor productivity ("TFP") growth.[3] However, for purposes of calibrating an OM&A-only revenue cap, the productivity calculation should by definition contain only OM&A inputs. The inclusion of capital as an input would bias the X factor unless the growth rates of capital inputs and non-capital inputs were identical. Therefore, the appropriate X factor measure for an OM&A-only revenue cap must rely on a partial measure of productivity in which input growth includes labor and materials but excludes capital. Such a partial measure of productivity is by definition <u>not</u> TFP growth (since the "total" in total factor productivity refers to a study that includes all inputs, including capital).

11. In Ontario, the X factor consists of two components: a productivity factor and a stretch factor. Under both the "Price Cap IR" and "Annual IR Index" menu options set forth in the OEB's Renewed Regulatory Framework, the productivity factor reflects electricity distribution

[2] If the regulated company is included in the sample of firms in the TFP growth study, the company's actions would influence the results of the study to such a small degree that the effect would be ignored by management's decision-making.

[3] Where $\%\Delta TFP = \%\Delta Outputs - \%\Delta Inputs$.

sector TFP growth in Ontario.[4] A third menu option, Custom IR, allows the electricity distributor to adjust rates over a five-year period according to an individually tailored multi-year rate plan, which may include a partial revenue cap. Under such an approach, an annual rate adjustment mechanism is informed by three elements: (1) the distributor's own forecasts; (2) the OEB's inflation and productivity analyses; and (3) benchmarking. The productivity factor component of the X factor in a partial revenue cap framework should be based on a partial productivity ("PFP") growth rate, which would be based on growth of OM&A inputs relative to output growth.[5]

2.2 Hydro Ottawa's Proposed Productivity Factor

12. Hydro Ottawa has proposed to adjust OM&A-related revenue by an X factor that consists of two components: (1) a productivity factor based on industry TFP;[6] and (2) a stretch factor based partially on a benchmarking analysis.[7] As discussed below, the proposed productivity factor biases the X factor downward.

13. Hydro Ottawa has proposed to adopt the OEB's productivity factor of 0.00 percent. This productivity factor typically applies to utilities operating under either the "Price Cap IR" or the "Annual IR Index" menu options under the Renewed Regulatory Framework. As explained in Section 2.1, these two menu options rely on a TFP growth rate that has been calibrated for the purpose of setting a price cap, where prices have been set to recover a distribution utility's total revenue requirement, inclusive of both OM&A and capital. The OEB's accepted productivity factor was not set for the purpose of adjusting an OM&A-only revenue cap. As such, the proposed productivity factor, which, as the Company states, is based on TFP growth, is not appropriate.

14. The appropriate productivity factor for Hydro Ottawa's proposed revenue cap, which only adjusts OM&A-related revenue and not capital-related revenue, would exclude capital input

[4] "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach." *Report of the Board*. Ontario Energy Board. October 18, 2012. p. 13.

[5] This has in some cases been termed "partial factor productivity" (PFP) since it does not include all inputs (namely capital) of a TFP study. We note that because the value of OM&A PFP is conditional on the quality and quantity of capital input growth that is paired with OM&A growth to produce output growth. In other words, changing the quality or quantity of capital input growth that is used in conjunction with OM&A input growth will yield a different OM&A "PFP" result. Since physical capital and operating costs are intertwined, productivity associated with only certain inputs is difficult to measure. Thus, the OM&A adjustment factor can be thought of as a partial factor productivity measure if it is understood that the value of this PFP is dependent on the value of unmeasured inputs (i.e., capital) and that changes in unmeasured inputs will change the value of this PFP.

[6] Exhibit 1, Tab 3, Schedule 1, p. 20, line 15.

[7] Ibid, p. 20-23.

growth from the calculation of productivity growth. The appropriate productivity factor, a PFP growth rate, should be based on the growth of OM&A inputs relative to output growth. As explained above, industry PFP growth would not equal TFP growth, except by coincidence. This means that the OEB's productivity factor of 0.00 percent should not be automatically applied to a revenue cap that adjusts only OM&A-related revenue. Instead, the productivity factor component of the X factor should rely on an empirical analysis of industry productivity that excludes capital input quantities.

2.3 Ontario Electricity Distribution Sector Partial Productivity

15. CA Energy Consulting conducted a partial productivity analysis that includes 84 Ontario distribution utilities over the period 2013-2023 using the OEB's Total Cost Benchmarking data. The analysis calculates the PFP growth rate as follows:

$$\%\Delta PFP_{OM\&A} = \%\Delta Outputs - \%\Delta Inputs_{OM\&A}$$

Where $Outputs$ reflects a weighted average of the number of customers served, peak demand (kW), and delivery volumes (kWh), and $Inputs_{OM\&A}$ contains the inputs associated with OM&A expenditures. Further details on the data and methods of this calculation can be found in Appendix 1.

16. The analysis finds that, during the period 2013-2023, the average partial factor productivity growth rate was +1.29 percent. Table 1 presents the annual growth rates for each year. Note that in 2020, the year during which the COVID-19 pandemic began, OM&A PFP grew 8.38 percent. This is likely because outputs remained relatively unchanged while certain OM&A spending was halted. If that year is excluded, the average PFP growth rate was +0.50 percent.

Table 1:
Ontario Electricity Distribution Annual PFP Growth

Year	PFP Growth
2014	-2.86%
2015	-0.55%
2016	5.78%
2017	0.75%
2018	5.01%
2019	0.12%
2020	8.38%
2021	0.50%
2022	-2.87%
2023	-1.34%
Avg	**+1.29%**
Avg, w/out 2020	**+0.50%**

17. The findings presented in Table 1 align with recent empirical work conducted with data from US distribution utilities.[8] The data indicates that capital input growth has been greater than OM&A input growth in recent years. Elevated capital input growth has reduced the TFP growth rate, which results in a substantive divergence between TFP growth and OM&A PFP growth.

2.4 Productivity Factor Recommendations

18. For the reasons explained in Sections 2.1 and 2.2, the OEB's price cap productivity factor of 0.00 percent is not an appropriate productivity factor for Hydro Ottawa's OM&A-related revenue cap. The proper productivity factor should exclude capital inputs from the productivity calculation.

19. The productivity factor should reflect expected future productivity growth during the revenue cap term, which in this case spans 2026 to 2030. Typically, an empirical measure of historical average productivity serves as an estimate for this expected growth rate. The data indicate that average OM&A PFP growth during the years of available data was equal to +1.29 percent. However, given the COVID-19 disruption of work that occurred across the

[8] "Direct Testimony of Mark E. Meitzen and Nicholas A. Crowley," Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-150, August 17, 2023.

industry in 2020, CA Energy Consulting recommends the use of a historical average excluding 2020 as the productivity factor within Hydro Ottawa's X factor. This more conservative recommended productivity factor is +0.50 percent.

3. BENCHMARKING ANALYSIS AND STRETCH FACTOR

3.1 Benchmarking Background

20. In Ontario, the stretch factor is determined by a distributor's efficiency ranking. This efficiency ranking is obtained from an econometric benchmarking analysis, which compares a distributor's actual costs to the costs predicted by an econometric model developed by Pacific Economics Group ("PEG"). The econometric model is estimated using utility industry data in Ontario and captures the relationship between utility operating conditions and cost.

21. A distributor's cost performance, as estimated in the benchmarking regression, is used to establish a stretch factor over the five-year term. Under the "Price Cap IR", the stretch factor is updated each year based on the latest data and analysis produced by PEG during the five-year term.[9] The stretch factor assignment is based on Table 2, established in a 2013 OEB report:

Table 2:
Demarcation Points and Stretch Factor Values[10]

Group	Demarcation Points for Relative Cost Performance	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within +/-10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

[9] "Filing Requirements For Electricity Distribution Rate Applications -2025 Edition for 2026 Rates" Chapter 3, Ontario Energy Board, June 19, 2025, p. 6.
[10] "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors." *Report of the Board.* Ontario Energy Board. December 4, 2013. EB-2010-0379.

3.2 Hydro Ottawa's Proposed Benchmarking Study and Stretch Factor

22. Hydro Ottawa has argued that its operating conditions, as measured by the variables in PEG's econometric model, need to be adjusted so that the Company's cost performance is not underestimated. Specifically, the Company stated that it uses "adjusted values, including total circuit kilometers that include secondary lines (in addition to its primary lines), which had been omitted from the model in the past. This inclusion is consistent with existing practices and, if included correctly, will produce a more accurate estimate of the utility's predicted total costs. Further adjustments are made for the impact of provincial conservation and demand management ("CDM") programs on kW and kWh, and Other Revenues."[11]

23. Hydro Ottawa does not plan to adjust its stretch factor during the rate term.[12] However, as explained in Section 5, Hydro Ottawa proposes to adjust ESM if the Company falls into a less efficiency cohort according to the annual cost benchmarking results.

3.3 Corrections to the Modified Benchmarking Analysis

24. For the purpose of this discussion, we assume Hydro Ottawa's inputs for the proposed adjustments are correct. While the adjustments may not be entirely correct, we will demonstrate that even if they are, the Company will significantly overstate its performance using its proposed methodology. We begin by discussing the bias that likely results from correcting OM&A for Other Revenues before moving on to the circuit kilometer and CDM adjustments. In all cases, the issue stems from correcting Hydro Ottawa's data without correcting the data for all other companies in the sample and re-estimating the parameters of the model before predicting Hydro Ottawa's costs.

3.3.1 Adjustments Related to Other Revenues

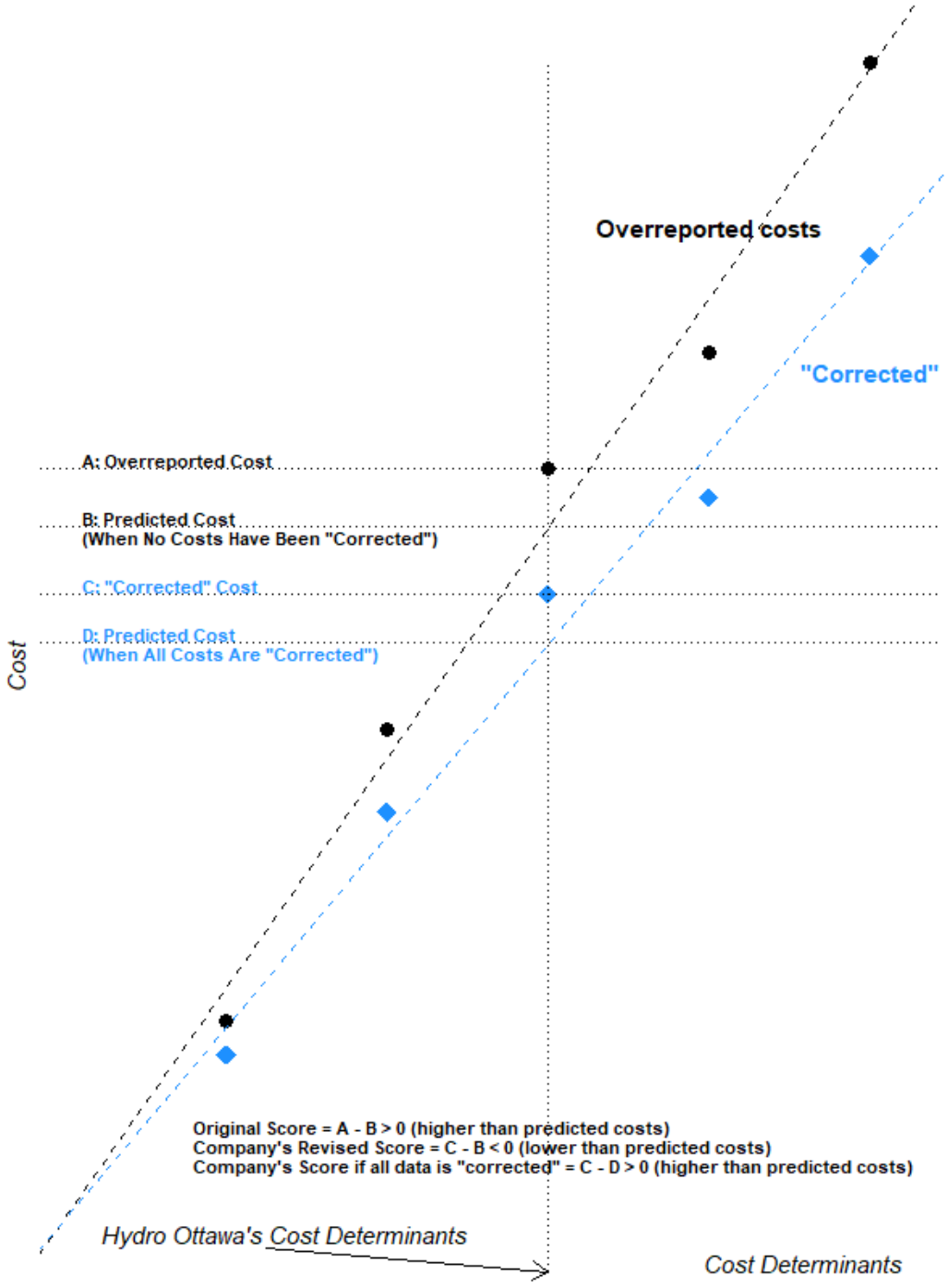
25. The Company has noted that Other Revenues compensate it for OM&A costs that are unrelated to its performance. For instance, the Company receives rental revenue for property that it leases to Hydro One, and thus its OM&A costs can fluctuate due to actions taken by Hydro One and not the Company. Hydro Ottawa argues that Other Revenues are a proxy for costs within OM&A that it cannot control, and should thus be removed.

[11] Exhibit 1, Tab 3, Schedule 3, page 8.
[12] Exhibit 1 Tab 3 Schedule 1, page 19.

26. However, if this is the case for other companies in the sample, then adjusting Hydro Ottawa's OM&A cost and comparing it to the model's prediction without correcting all other company costs and re-estimating the model's parameters will overestimate Hydro Ottawa's performance. This problem can be visualized in the illustrative example shown in Figure 3.1.

Figure 3.1:

Overstatement of Company Performance from OM&A Correction



27. In this figure, the X axis summarizes the model inputs or cost determinants (e.g. customers, capacity, etc.) and the Y axis represents cost. Each data point represents a company; the black circles show the companies' costs without Other Revenues removed and the blue diamonds remove these costs. Hydro Ottawa's cost determinants are denoted by the vertical dotted line. Its "overreported cost" – i.e. its OM&A cost before deducting Other Revenues – is denoted by the black circle intersecting the vertical dotted line. The existing model parameters are a reflection of these overreported costs; the model's predicted cost for each company is represented by the black dashed line, which best fits these data points. Hydro Ottawa's performance is computed as the difference between its *overreported cost* and the *predicted cost* from the existing model, or A – B in the plot.

28. The Company argues that it should correct its cost for Other Revenues. This "corrected" cost is shown as the blue diamond that intersects the vertical dotted line.[13] However, in this example, all companies in the sample have overstated costs. If corrections were made to the data of all companies, the data would be made up of strictly blue data points. At this point, the model's parameters would be re-estimated to reflect the corrected data, and a lower cost is predicted for each company. This makes sense: for any value of cost determinants, actual costs would be lower, and thus the updated model will predict lower costs for each company. Notice that if one compares the company's overreported cost to the existing model's prediction (comparing the black data point to the black dashed line), the difference is similar to the difference between the company's corrected cost and the updated model's prediction (comparing the blue data point to the blue dashed line). In either case, the company has slightly higher costs than predicted. However, if the company's corrected cost is compared to the existing model's prediction (comparing the blue data point to the black dashed line), the company's cost is below the model's prediction, and the conclusion about its cost performance is flipped. This is what the Company has proposed to do, and it explains why its cost performance has improved so dramatically after correcting its input data without correcting the data of other companies in the sample and updating the model's prediction to reflect this corrected sample.

29. The conclusion that the Company's performance is likely overstated is supported by the Company's response to 1-Staff-14, in which it noted that "[a]ll utilities submit Other Revenues as part of their annual RRR. However, the PEG Model omits these auxiliary revenue programs while accounting for their costs. However, the amount of other revenue

[13] While we are assuming these are in fact corrections in this analysis, we are highlighting the possibility that Hydro Ottawa's proposed data revisions are incorrect.

expenses that distributors are recording in OM&A or Other Revenue will influence outcomes."[14]

3.3.2 Adjustments Related to Total Circuit Kilometers and CDM

30. Like the adjustment to OM&A cost, it is our view that adjustments to the Company's input data like circuit kilometers, kW, or kWh without accounting for adjustments to all input data in the sample will result in an overstatement of the Company's performance. This can be visualized in Figure 3.2. The example is analogous to the example depicted in Figure 3.1; but rather than overstating costs as in the previous example, input data are understated. Hydro Ottawa's original and corrected cost determinants are depicted with two dotted vertical lines.

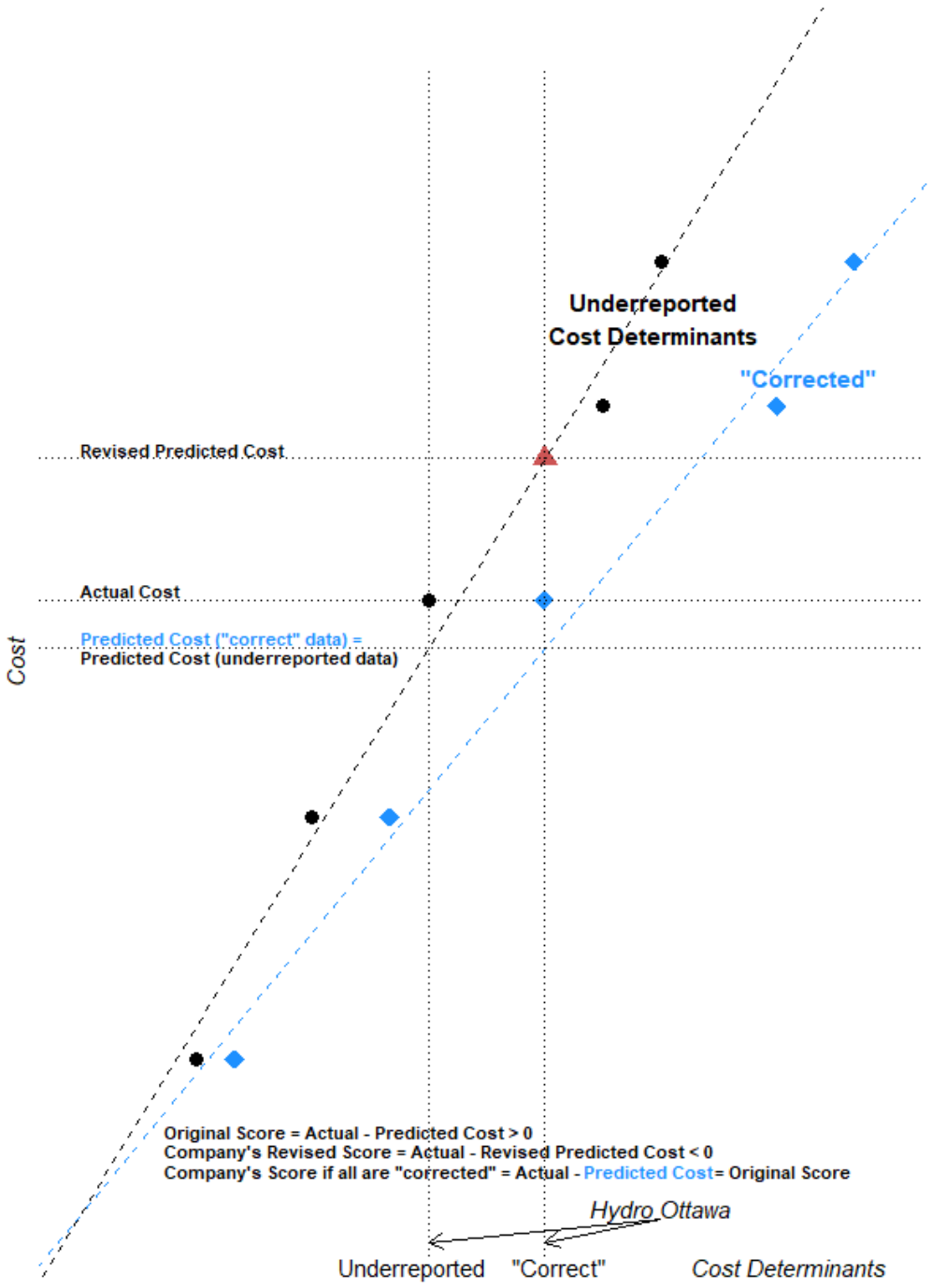
31. Before the adjustment to its input data, Hydro Ottawa's performance can be visualized as the vertical difference between the black data point that intersects the "underreported" vertical dotted line (the left-side vertical line) and the existing model's prediction, shown as the point where the black dashed line intersects the same "underreported" vertical dotted line. In this example, the Company has slightly higher costs than predicted by the model. The Company has proposed to "correct" its input data and predict its costs using the existing PEG regression model. The Company's corrected input data is denoted by the right-side vertical line. The existing model's prediction of the Company's costs at this corrected value is denoted by the red triangle, which is far above the Company's actual cost. This means that the Company will look far more efficient when the correction is made only to its own data and not to the data of any other companies in the sample.

32. However, if all data in the sample are "corrected" and the model is re-estimated to reflect the correct data, the Company's actual cost will be compared to the prediction based on the dashed blue line, not the dashed black line. Doing so will result in the exact same performance score as if no data had been corrected at all. This can be seen by noting that the vertical difference between the black data point and the black dashed line is precisely the same as the difference between the blue data point and the blue dashed line. In other words, because one would ideally correct all sample data and re-estimate the model to reflect the correct data, the Company's performance before its input data are corrected is a better indicator of its actual performance than after its input data are corrected and the rest of the sample is left unchanged.

[14] Interrogatory Response 1-Staff-14.

33. The conclusion that Hydro Ottawa's performance is likely overstated in the Company's proposed benchmarking approach is supported by the Company's response to 1-Staff-14, in which it noted that "All utilities in Ontario omit the effects of Conservation and Demand Management on their deliveries (kWh) and capacity (kW). An additional step would be required to add back in and quantify the loss of load resulting from these programs." The Company's response acknowledges that the underlying data used to estimate the PEG model has not been adjusted to account for CDM-related kWh and kW for any of the other companies in the sample. Additionally, in this response, Hydro Ottawa notes several other companies that have submitted total circuit kilometer corrections to the OEB.

Figure 3.2:
Overstatement of Company Performance from Input Data Correction



3.3.3 Additional Considerations

34. In the above examples, the measurement error in OM&A, circuit kilometers, kW, and kWh as a percentage of the true data is the same for all companies. In reality, the measurement error will almost certainly vary across companies, and some companies may have very little measurement error. Regardless, unless Hydro Ottawa is the only company with "incorrect" data, the Company's proposed approach to correcting its stretch factor will lead to a biased revision of its efficiency score: the Company will appear to be more efficient than it actually is after its data have been updated.

35. Hydro Ottawa's current stretch factor is 0.45%. In addition to recommending a reduction in its stretch factor from 0.45% to 0.30% as a result of these data corrections, Hydro Ottawa has argued that it should receive a further reduction from 0.30% to 0.15%, which reflects an anticipated exogenous reduction in productivity stemming from accelerated electrification, which will increase costs during the 2026-2030 term. Specifically, the Company notes "the model's historical data and assumptions fail to account for the increase capital expenditures, workforce expansion, and technological upgrades required to support the rapid adoption of electric vehicles, the integration of distributed energy resources, expanded housing connections, and the broader modernization of the grid to accommodate higher loads."[15]

36. Hydro Ottawa also justified a reduction of the stretch factor over the 2026-2030 rate term to 0.15% due to "embedded productivity" in its 2026 OM&A Test Year forecast. The Company states that, for example, online billing adoption supports this position: "Online billing enrollment was 55% as of the end of 2020, and is projected to reach 80% by the end of 2025, with that level being maintained through 2030 (inclusive of customer growth)."[16]

3.4 Stretch Factor Recommendations

37. We do not recommend that the OEB accept the Company's revised cost performance estimates, as the approach contains econometric flaws. When Hydro Ottawa's data is entered into the PEG model without revisions, the resulting performance score corresponds to cohort 4, which indicates a stretch factor of 0.45% according to the OEB's stretch factor mapping shown above in Table 2. Therefore, if Hydro Ottawa were operating under the Price Cap Index menu option, the correct stretch factor would be 0.45%.

[15] Exhibit 1, Tab 3, Schedule 1, page 22.
[16] Exhibit 1, Tab 3, Schedule 4, page 25.

38. As noted in Section 3.3.3, Hydro Ottawa suggests that the PEG cost benchmarking model will not generate an accurate stretch factor over the 2026 to 2030 term because of increasing electrification costs.[17] The Company has not supported this claim empirically. The PEG model accounts for cost changes due to variation in total customers, peak load, and volumes—key variables in predicting distribution utility costs. Increased costs associated with electrification will likely affect all Ontario distributors, and therefore it is not clear that Hydro Ottawa's relative cost performance will shift substantially. For this reason, and the reasons described above, we are not convinced that changes should be made to the stretch factor based on Hydro Ottawa's criticisms of the PEG regression model in this proceeding.[18]

39. Questions about the regression model aside, we acknowledge a broader question about how to determine the stretch factor value in a revenue cap plan. First, if the purpose of the stretch factor is to anticipate cost efficiency improvements expected during the five-year term and return a portion of those efficiency improvements to customers, it is reasonable to consider the extent to which additional cost efficiency gains can be expected after several years of indexed cap regulation. A company that has operated under an indexed cap framework for twenty years may be operating on its efficiency frontier. In such a scenario, an attenuated stretch factor may be reasonable. However, any change to the mapping between relative company performance and the appropriate stretch factor should apply to all companies in Ontario, as the Company has not offered clear evidence that it is in a unique position relative to its peers which would warrant a deviation from the recommendation in Table 2.

40. It should be noted that under the Company's proposed framework, the stretch factor is applied only to O&M-related revenue. Therefore, the Company's O&M cost performance would ideally be benchmarked against its peers rather than its total cost. To our knowledge, this is not possible because the PEG econometric model is a total cost model.

41. Identifying areas of expected future efficiency improvements and labeling the "embedded productivity" to reduce the current stretch factor is not recommended. Indexed cap PBR provides a regulated utility with an incentive to seek improvements in cost efficiency during the PBR term as they are able to retain the efficiency gain as profits until the end of the PBR term. Customers benefit from cost efficiencies at the start of the next PBR term through rebasing. For example, the Company was able to increase its realized ROE, all else equal,

[17] Exhibit 1, Tab 3, Schedule 1, page 22.

[18] Furthermore, the stretch factor applies only to a cap on OM&A-related revenue, meaning that expectations of capital spending related to electrification should not bear on the choice of stretch factor.

through the increase of online billing adoption in the current rate term (2021-2025), such that customers will receive the cost efficiency benefit at rebasing. This information does not inform the stretch factor value in future rate terms.

42. Finally, the Company proposes to maintain the same stretch factor value over all years of the Custom IR term. Generally, updating the stretch factor each year is preferred because it incorporates more recent information about utility performance. One reason that exists in other jurisdictions for maintaining a static stretch factor is that an annual cost benchmarking update imposes administrative burden on the utility. In Ontario, however, the OEB provides updated cost benchmarking results each year. Given (1) a preference for more recent data; (2) a limited administrative burden associated with making an annual stretch factor update in this case; and (3) our recommendation against the contingent ESM (see Section 5), we recommend using the OEB's annual benchmarking results to update the stretch factor each year of the term.

4. GROWTH FACTOR

4.1 Growth Factor Background

43. A principled revenue cap formula includes a growth factor, in addition to the inflation and X factors. The growth factor takes the form of a percentage change, reflecting the percentage change in outputs served by the utility. The correct growth factor value should reflect the outputs used in the measurement of productivity for the purpose of setting the X factor. For example, if the X factor relies on customers as the productivity output measure, the growth factor should reflect the growth in the number of customers served during each year of the revenue cap plan. The percentage change in growth adjusts revenues, in addition to inflation and X.

44. Revenue caps include explicit growth factors, while price caps do not, because price caps implicitly incorporate a growth factor by definition.[19] As such, the Renewed Regulatory Framework does not refer to a growth factor in its definition of the Annual Adjustment Mechanism for any of the three methods for setting distribution utility rates in Ontario.

[19] Under a price cap, revenue has no upper limit. If quantities sold increase—either in the form of larger sales volumes or an increase in customers served—revenue increases accordingly.

4.2 Hydro Ottawa's Proposed Growth Factor

45. Hydro Ottawa has proposed a growth factor set equal to a cost-weighted average of forecasted growth rate of system capacity (MVA) and number of customers served during years 2025 through 2030. The growth factor, as proposed, would equal 3.23 percent each year for all years of the revenue cap term.[20]

46. The proposed methodology for setting the growth factor differs from the current "Custom Price Escalator Factor" used to escalate OM&A during the years 2022 to 2025. The growth factor under the current framework relied upon a forecasted average growth rate in the number of customers served of 0.97 percent, multiplied by a scaling factor of 0.35 percent, generating an annual value of 0.34 percent.[21]

47. For the current application, by averaging the growth rate of customers served and the growth rate of system capacity, and by removing the scaling factor, Hydro Ottawa proposes a growth factor that is more than nine times larger than the currently effective growth rate under the Company's 2021-2025 Custom IR plan.

4.3 Growth Factor Recommendations

48. It is reasonable for Hydro Ottawa to include a growth factor in its revenue cap formula. However, we recommend adjustments to the Company's calculation of this value. As currently proposed, the growth rate in the number of customers includes growth attributable to suite-metered customers that have been disaggregated into separately-metered accounts.[22] This is problematic because it improperly biases the growth rate, creating the appearance of an expanding customer base in a circumstance where no new customers are added. In addition, we suggest using a revenue-weighted average to align with the weights used to calculate the productivity factor (see Appendix 1).[23]

49. The growth rate calculation also presents an additional question: should the growth factor reflect a forecast, or should the growth factor reflect actual output growth as established *ex post* with Hydro Ottawa's output data? The economic derivation of the revenue cap formula allows for flexibility on this point. One benefit of the forecast approach is that it can be used to reorient growth incentives. A forecasted growth factor affixes growth-related revenue

[20] Exhibit 1, Tab 3, Schedule 1, p. 24.
[21] Exhibit 1, Tab 2, Schedule 5, p. 7.
[22] Technical Conference, EB-2024-0115, September 25, 2025, p. 5, Line 19.
[23] Christensen, Shoech, Meitzen, *Traditional Telecommunications Networks,* Chapter 3: Telecommunications Productivity, 2003, p. 104.

adjustments regardless of actual customer additions or increased sales, which may be preferred in sectors in which policymakers aim to mitigate output growth.[24] The province of Ontario has no policy for electricity distribution services aimed at reducing output growth, so such a benefit does not provide sufficient value in this case. Hydro Ottawa states that an additional advantage of the forecasted approach is a reduced complexity for setting rates and managing operational budgets.[25]

50. We are not convinced that annually reporting the actual growth rate in capacity and customers served constitutes a substantial increase in complexity for rate setting. However, we acknowledge that output growth volatility may increase complexity for budget management.

51. The forecast approach presents two drawbacks. First, it introduces an information asymmetry problem: the Company has better information than the regulator for purposes of setting and assessing forecasted output. Second, it allows the utility to collect for the cost of output growth even if such growth does not occur.

52. For these reasons, we recommend that Hydro Ottawa's growth factor is set equal to a revenue-weighted average forecasted growth rate of customers and capacity, where the customer growth rate excludes growth attributable to the disaggregation of suite-metered customers. Furthermore, we recommend that the Company tracks its actual growth rate over the Customer IR term, so that in the Company's next rebasing application it trues up revenue growth attributable to the forecasted growth factor to the realized weighted average growth rate. This recommendation corrects the growth factor calculation, avoids the budgetary complexity of annual changes to the growth factor, and provides customers with an assurance that the growth factor will not result in inaccurately calculated revenue over the long run.

5. EARNINGS SHARING MECHANISM

5.1 ESM Background

53. An ESM is a means of sharing with customers the surplus or deficit caused by a utility deviating from its allowed return on equity ("ROE") target. Although ESMs may operate as

[24] For example, consider a policy goal to reduce a gas distribution utility's incentive to connect new gas customers. By establishing a forecasted customer growth rate to adjust rates over a five-year period, the gas distributor has a greatly reduced incentive to connect customers during those five years.
[25] Interrogatory Response 1-Staff-10.

guardrails in a PBR plan, they also dampen efficiency incentives because the utility does not retain all of its efficiency gains if it must share those gains with customers. The OEB does not require a Custom IR framework to include an ESM.[26] However, the OEB has stated that a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings deadband.[27]

5.2 Hydro Ottawa's Proposed ESM

54. Hydro Ottawa has proposed an ESM that is contingent on cost performance, as measured by an annual cost benchmarking analysis. The Company stated:[28]

> "Hydro Ottawa must maintain its Cohort III efficiency position in the adjusted PEG Model (as described in Attachment 1-3-3 (A) - PEG Benchmarking Analysis) by the end of the rate term, in order to be able to retain any cumulative earnings between 0 and 150 basis points. Failure to meet this condition results in Hydro Ottawa sharing all earnings exceeding the approved ROE with customers."

55. The Company's proposed ESM allows the utility/shareholders to retain earnings above the allowed ROE up to 150 bps, but only if it maintains or improves its cost efficiency cohort. The proposed ESM is asymmetric, which means that the Company cannot collect additional revenue if it fails to earn its allowed ROE.

5.3 ESM Recommendations

56. We recommend that the Company operate under an asymmetric ESM with a 300-basis point deadband, 50% earnings sharing, and no contingencies based on cost performance. The revenue cap formula recommended in this report provides sufficient incentive for the Company to control its cost growth. An ESM that shares any earnings in excess of allowed ROE reduces the cost efficiency incentives of the plan. Furthermore, if the Company's costs increase such that the cost benchmarking results shift Hydro Ottawa to a less efficient cohort, the Company is not likely to have any earnings above the allowed ROE to share anyway.[29]

---

[26] "Handbook for Utility Rate Applications." Ontario Energy Board. October 13, 2016.

[27] "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach." *Report of the Board*. Ontario Energy Board. October 18, 2012. p. 13.

[28] Exhibit 1, Tab 3, Schedule 1, page 27.

[29] Since the Company's revenues are constrained by the plan, cost increases will reduce earnings below the allowed ROE, in which case the ESM, as proposed, would be unlikely to benefit customers.

6. DEFFERAL AND VARIANCE ACCOUNTS

57. Electric utilities incur costs and make capital outlays to maintain and grow service in accordance with their obligation to serve customers and, recently, electric utilities across North America have increased spending in a broad array of categories, from cybersecurity to technologies that support the electrification of the economy. Utility revenue constraints under indexed caps must balance the outcomes related to service obligations, policy goals, and cost efficiency. As such, indexed cap frameworks generally contain revenue support for capital expenditures (such as Hydro Ottawa's forecasted approach with variance accounts proposed in the present filing), as well as other mechanisms that track costs.

58. Under a revenue cap framework, variance accounts may reasonably serve to recover costs that are volatile, uncertain, and/or beyond the control of the utility. In Ontario, a utility must demonstrate that costs relate to the following criteria in order to qualify for recovery under a Group 2 variance account:[30]

    - Causation – Outside the base upon which rates were derived.
    - Prudence – Cost-effective.
    - Materiality – Exceed the OEB-defined materiality threshold.

59. While, for the reasons stated above, cost trackers or variance accounts may be necessary in some cases, such mechanisms also reduce the cost efficiency incentives of the rate framework. This is because trackers and variance accounts link utility revenues with costs more closely than the two would be linked under a pure indexed cap approach. A degree of judgement is required in assessing whether the characteristics of a particular set of costs warrant targeted cost recovery in light of corresponding lower efficiency incentives.

5.1 Hydro Ottawa's Proposed Variance Accounts

60. Hydro Ottawa has proposed modifications to five variance accounts and has proposed three new variance accounts. Table 3 summarizes these proposed changes.[31] Asymmetrical variance accounts to track underspending operate by refunding to customers revenue collected above the costs associated with each account. Asymmetrical variance accounts to track additional costs collect additional revenue from customers. Symmetrical accounts operate by refunding to customers revenue collected above costs and allow Hydro Ottawa to collect additional revenue in the case of a shortfall.

[30] "Filing Requirements For Electricity Distribution Rate Applications -2025 Edition for 2026 Rates" Chapter 2, Ontario Energy Board, December 9, 2024, p. 68.
[31] Exhibit 1, Tab 3, Schedule 1, pp. 9-11.

Table 3:
Hydro Ottawa's Proposed Variance Accounts

Asymmetrical Sub-Accounts	Symmetrical Sub-Accounts
To track underspending: • System Access – except relocations and "Growth Capital Development Additions"[32] • System Renewal and System Service • General Plant *To track additional costs:* • Tariff Impacts	• System Access – plant relocations and Growth Capital Development Additions. • Connection Cost Recovery Agreement (CCRA) Payments • Non-Wires Solutions (NWS) • Large Load Revenue

61. The proposed Capital Additions Variance Account (which consists of the first three sub-accounts under the Asymmetrical category) continues the existing mechanism, with some changes.

62. Under the Company's proposal, no change would be made to the CCRA variance account. The proposed Non-Wires Solutions (NWS), Large Load Revenue, and Tariff Impacts variance accounts are new.

5.2 Incentive Considerations Regarding Variance Accounts

63. The weakness of both asymmetric and symmetric variance accounts as they are currently structured is that they do not incent cost control. This is clearly true under a symmetric variance account, as the Company may potentially recover whatever it spends.

64. This also applies to the asymmetric variance accounts associated with capital in this proceeding because the Company's revenue requirement associated with capital is forecasted. If the Company anticipates in its forecast a range of potential costs associated with a capital project, under an asymmetric variance account the Company has an incentive to forecast spending near the upper bound of that range in order to reduce risk, knowing that it will not be able to collect if the cost is ultimately higher than its forecast. Therefore, it should be recognized that an asymmetric variance account may not necessarily lead to more efficient spending levels. In fact, the asymmetric approach as structured could lead to higher spending levels than the symmetric variance account when the project's costs are more uncertain. Therefore, we do not recommend asymmetric variance accounts be adopted for

[32] As defined by Hydro Ottawa in Exhibit 1, Tab 3, Schedule 1, p. 10.

categories of forecasted spending in which project costs are highly uncertain and the OEB lacks sufficient information to determine the validity of the forecast.

65. The inclusion of a symmetric or asymmetric variance account also interacts with other parts of the plan if there is substitutability between capital and O&M inputs (e.g. if the Company can allocate spending away from capital toward O&M or vice versa to complete a project). For example: under the OM&A revenue cap, a growth factor should be included. If Hydro Ottawa's forecast approach for the growth factor were accepted, the Company would not be compensated for OM&A spending associated with *unexpected* customer or load growth. Under such a scenario, a rational company would inefficiently capitalize more of its spending if it can collect additional revenue through a symmetric variance account. This is an additional reason for modifying Hydro Ottawa's proposed growth factor so that it trues up to actual output growth rather than a forecast.

5.3 Variance Account Recommendations

66. Hydro Ottawa stated that it has proposed changes to its asymmetrical System Access sub-account to exclude commercial expansions.[33] To the extent that commercial expansions constitute a non-trivial portion of the Company's revenue requirement and are difficult to forecast, we recommend accepting this proposed change given our discussion in paragraph 61. Likewise, the Large Load connections impose uncontrollable costs that are difficult to forecast. We recommend allowing these costs to be recovered in a symmetrical variance account for the same reason.

67. Hydro Ottawa stated that the proposed NWS symmetrical variance account aims to facilitate innovations in line with the OEB's Framework for Energy Innovation.[34] A symmetrical variance account associated with NWS would, all else equal, provide support to the utility for undertaking projects that reduce the need for the addition of new physical plant. We consider revenue recovery under a symmetrical variance account for NWS to be appropriate for the same reasons discussed regarding the System Access symmetrical account: these costs are difficult to forecast and could constitute a material portion of company costs over the five-year term.

68. We propose a modification to the Company's proposed asymmetrical Tariff Impact deferral account. While price increases related to tariff hikes may be easy to measure, costs

[33] Exhibit 1, Tab 3, Schedule 1, p. 30.
[34] Ibid, p. 31.

associated with supply chain disruptions are less straightforward from an accounting perspective. For example, if the Company requires a transformer that is imported, and supply chain disruptions delay the arrival of the transformer by three months, it is not straightforward to determine the cost associated with that delay. Or, if transformers become more expensive due to scarcity—separate from but related to an existing tariff hike—the dollar value to include in this deferral account may not be clearly defined on an invoice. For this reason, we recommend that the Tariff Impact deferral account is accepted, but only for costs that are clearly quantifiable from accounting data as driven solely by tariff changes, and not secondary supply chain effects.

69. In the opinion of CA Energy Consulting, the CCRA variance account, which Hydro Ottawa proposes to keep unchanged from the existing mechanism, is reasonable.

6. CONCLUSIONS

70. This report contains recommended updates to Hydro Ottawa's proposed Custom Incentive Regulation framework, which will establish rates between 2026 and 2030. Table 4 summarizes our recommendations regarding the cap on OM&A-related revenues. The combined productivity factor and stretch factor equate to an X factor of +0.95%. We consider the proposed variance accounts to be reasonable from an economic standpoint, with the exception of the portion of the Tariff Deferral account associated with supply chain disruptions, as discussed in Paragraph 68.

Table 4:
Recommended Updates to Hydro Ottawa's Revenue Cap

Framework Element	Hydro Ottawa's Proposed Approach	Recommended Approach
Productivity Factor	0.00%	+0.50%
Stretch Factor	+0.15%, Static over the 5-yr term	+0.45%, Updated annually
ESM	50/50 sharing above 150 bps of ROE, subject to efficiency test	50/50 sharing above 300 bps, no efficiency test
Growth Factor	+3.23%	*To Be Recalculated by Hydro Ottawa*[35]

[35] The recalculation would set the growth rate equal to a revenue-weighted average forecasted growth rate of customers and capacity, where the customer growth rate excludes growth attributable to the disaggregation of suite-metered customers. In addition, we recommend that revenues associated with the growth factor are trued-up to actual growth upon rebasing following this five-year Custom IR term.

APPENDIX 1: DERIVATION OF THE REVENUE CAP FORMULA

Overview

The proposed revenue cap in Hydro Ottawa's PBR framework applies only to O&M-related costs. As such, the productivity component of the X factor within the revenue cap formula should be calibrated using O&M-related inputs. Mechanically, the calculation of the PFP growth rate resembles the calculation of Total Factor Productivity (TFP) growth, but without including capital inputs.

PFP Calculation Data and Methods

As in the calculation of TFP growth, the PFP growth rate equals a measure of output growth minus a measure of input growth.

$$\%\Delta PFP_I = \%\Delta Output_I - \%\Delta Input_I$$

Because this is based on an industry average, we use the subscript "I". The output growth measure in the PFP growth study is based on a revenue-weighted average of billable output growth, which includes customer growth, capacity (kW) growth, and growth in deliveries (kWh). The input growth measure is an inflation-adjusted measure of OM&A cost growth.

The data for this analysis was obtained from the OEB cost benchmarking study Excel file ("Benchmarking Update Calculation 2024.xlsx"). From this file, the input growth measure for each company is "Percent Change in OM&A" minus "OM&A Index Growth [30% GDPIPI growth + 70% AWE Growth]." The output growth measure is an average of the growth in "Number of Customers," "Delivery Volume," and "Annual Peak Demand", with the weights determined by Hydro Ottawa's reported revenue shares for each variable.

The sample includes all companies in the cost benchmarking file. This dataset contains 52 Ontario distribution-only utilities in the year 2023, with more companies included in prior years.

Derivation of the OM&A Revenue Cap Formula

The OM&A revenue cap formula allows revenue to grow at the rate $I - X + G$. This ensures that the Company's revenue will increase at the same rate as its costs, assuming it maintains productivity growth consistent with that of the industry. The derivation of the formula is based on the theory that in competitive markets, over the long term, firms will earn zero economic profit. This is equivalent to the condition that revenue growth ($\%\Delta R_I$) is equal to cost growth ($\%\Delta C_I$). For the average company in the industry,

$$\%\Delta R_I = \%\Delta C_I \quad (1)$$

The rate of revenue change ($\%\Delta R_I$) can be decomposed into the rate of change in prices ($\%\Delta P_I$) plus the rate of change in billable outputs ($\%\Delta Output_I$).

$$\%\Delta R_I = \%\Delta P_I + \%\Delta Output_I \quad (2)$$

where the subscript I denotes the average company in the industry. Similarly, the percentage change in OM&A cost can be decomposed into the rate of OM&A input price growth ($\%\Delta W_I$) plus the rate of input quantity growth ($\%\Delta Q_I$).

$$\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I \quad (3)$$

Substituting (2) and (3) into (1) and rearranging,

$$\%\Delta P_I = \%\Delta W_I + \%\Delta Q_I - \%\Delta Output_I$$

$$\%\Delta P_I = \%\Delta W_I - (\%\Delta Ouptut_I - \%\Delta Q_I)$$

$$\%\Delta P_I = \%\Delta W_I - \%\Delta PFP_I \quad (4)$$

Using Equation (2):

$$\%\Delta R_I - \%\Delta Output_I = \%\Delta W_I - \%\Delta PFP_I$$

$$\%\Delta R_I = \%\Delta W_I - \%\Delta PFP_I + \%\Delta Output_I \quad (5)$$

where $\%\Delta PFP_I = \%\Delta Output_I - \%\Delta Q_I$ is industry OM&A PFP growth. Because this formula was derived for the average company in the industry, it is important to discuss what deviations from this formula are necessary for a given company *i.* It is generally assumed that companies face that same growth rate in input prices $\%\Delta W_I$ and should be able to match the average productivity growth rate in the industry of $\%\Delta PFP_I$. However, it should be recognized that output growth will differ exogenously between companies. This implies the following revenue growth cap for a given company *i:*

$$\%\Delta R_i = \%\Delta W_I - \%\Delta PFP_I + \%\Delta Output_i \quad (6)$$

Note that the weights used to calculate the growth factor $\%\Delta Output_i$ should be the same as the weights used to calculate output growth in the PFP (or TFP) growth study. For example, if the PFP calculation employs a revenue-weighted average of customer growth, kW growth, and kWh growth to set the output growth measure, the growth factor should also use a revenue-weighted average of outputs.

APPENDIX 2: RESUME OF NICK CROWLEY

Nick Crowley

RESUME

October 2025

Business Address:

Laurits R. Christensen Associates, Inc.
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Telephone: 608.216.7170
Email: nacrowley@caenergy.com
LinkedIn: https://www.linkedin.com/in/nicholasacrowley/

Academic Background:

Master of Science – University of Wisconsin-Madison, 2014, Economics
Bachelor of Arts – University of Wisconsin-Madison, 2012, Economics
Chartered Financial Analyst – Charter Awarded in October 2024
Certified Rate of Return Analyst – Awarded June 2025

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., Jan. 1, 2024-present
Senior Economist, Laurits R. Christensen Associates, Inc., Sept. 1, 2021-Dec. 2023
Economist, Laurits R. Christensen Associates, Inc., 2019-Aug. 31, 2021
Staff Economist, Laurits R. Christensen Associates, Inc., 2016-2018
Economist, Federal Energy Regulatory Commission, 2015-2016

Professional Experience:

I am an expert witness on issues in network economics, with an emphasis on corporate finance, cost allocation, rate design, and productivity measurement. In my time as a consultant, I have testified on behalf of major public utilities in rate proceedings, measured cost of capital and assembled corresponding reports, developed alternative rate designs, and forecasted electricity load for supply planning purposes. I have also performed extensive research for benchmarking purposes using publicly available data. My work includes marginal cost estimation and the development of marginal cost models for major electric utilities. My reports have been filed before regulatory authorities across North America. Prior to joining Christensen Associates Energy Consulting, I served as an Economist at the Federal Energy Regulatory Commission, where I assisted with energy industry benchmarking, market power studies, and the review and evaluation of natural gas pipeline rate cases.

PUBLIC TESTIMONY

"Direct Testimony of Nicholas A. Crowley and Daniel McLeod, PhD," New Hampshire Department of Energy, Docket DE 24-070, January 24, 2025.

"Pre-filed Direct Testimony of Nicholas A. Crowley," Florida Public Utilities Commission, Docket No. 20240099-El, August 22, 2024.

"Rebuttal Testimony of Mark E. Meitzen and Nicholas A. Crowley," Massachusetts D.P.U., D.P.U. 23-150, April 26, 2024.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, New Hampshire Department of Energy, Docket DE 23-039, December 13, 2023.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, Michigan Public Service Commission, Case No. U-21488, December 11, 2023.

"Direct Testimony of Mark E. Meitzen and Nicholas A. Crowley," Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-150, August 17, 2023.

"Direct Testimony of Nicholas A. Crowley," Nicholas A. Crowley, MS, Massachusetts D.P.U., D.P.U. 23-80 AND D.P.U. 23-81, August 17, 2023.

"Rebuttal Evidence," Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission, Proceeding 27388, April 28, 2023.

"Determination of the Third-Generation X Factor for the AUC Price Cap Plan," Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, Alberta Utilities Commission Proceeding 27388, January 20, 2023.

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, June 10, 2022.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 22-22, January 14, 2022.

"Rebuttal Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, April 23, 2021.

"Direct Testimony of Mark E. Meitzen Ph.D. and Nicholas A. Crowley, MS," Massachusetts D.P.U. 20-120, November 13, 2020.

PUBLICATIONS

"Trends and Drivers of Distribution Utility Costs in the United States: A Descriptive Analysis from 2008 to 2022." *Electricity Journal.* 37 (2024) 107397.

"Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities." *Utilities Policy.* Vol. 72, October 2021. (with Dr. Mark Meitzen)

REPORTS AND WORKING PAPERS

"Reopener Proceeding for ATCO Utilities: Rebuttal Report," with Dr. Daniel McLeod, Alberta Utilities Commission, Proceeding 29064, February 12, 2025

"Evaluation of Reopener Remedy Options," with Dr. Daniel McLeod, Alberta Utilities Commission, Proceeding 29064, November 29, 2024.

"Making Sense of Multi-Year Rate Plans," with Dr. Daniel McLeod, Technical Brief, October 2024.

"Cost of Capital Study," for Grand Bahama Power Company, Ltd. August 15, 2024.

"BC Hydro Performance-Based Regulation Framework," for the British Columbia Hydro and Power Authority." With Dr. Daniel McLeod and Dr. Mark Meitzen. December 21, 2023.

"2022 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Aidan Glaser-Schoff)

"2021 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Aidan Glaser-Schoff)

"Long Term Avoided Costs, for assessment of Resource Options Including Conservation Programs and LED Lighting." For Florida Public Utilities Company. 2021.

"Cost of Capital Study," For Grand Bahama Power Company, Ltd. April 15, 2021.

"2020 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Navya Kataria)

"Cost of Capital Study," St. Croix Valley Natural Gas Company, Inc. June 20, 2019.

"2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"Methodology and Cost Estimates for Generation and Transmission Services, 2021-2029." For Newfoundland and Labrador Hydro. November 15, 2018.

"Cost of Capital Study," Grand Bahama Power Company, Ltd. October 17, 2018.

"2018 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark)

"2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

"2017 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: Ex-post and Ex-ante Report for Customers with Net Energy Metering." (with Michael Ty Clark and Dan Hansen)

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: Ex-post and Ex-ante Report." (with Michael Ty Clark and Dan Hansen)

"Common Metrics Report: Performance Metrics for Regional Transmission Organizations, Independent System Operators, and Individual Utilities for the 2010-2014 Reporting Period." *Federal Energy Regulatory Commission Staff Report,* 2016.

CONFERENCE PRESENTATIONS

"Essentials of Costing: Embedded and Marginal Cost." With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics.* October 6, 2025.

"Introduction to Alternative Regulation." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2025.

"Costing and Pricing to Support Rate Innovation." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2025.

"Marginal Cost Analysis of Electricity Services for Utilities." With Michael Clark and Michael Vigdor. EUCI Workshop. May 28, 2024.

"Dynamic, Tailored, and Niche Rate Design." With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics.* October 8, 2024.

"Introduction to Alternative Regulation." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2024.

"Avoided Costs of Electricity Services." With Michael Clark and Michael Vigdor. EUCI Workshop. March 19, 2024.

"Essentials of Costing: Embedded and Marginal Cost." With Bruce Chapman. Wisconsin Public Utility Institute. *Energy Utility Basics.* October 10, 2023.

"Rate Design for Revenue Adequacy and Price Efficiency." With Bruce Chapman. Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

"Marginal Costs of Electricity Services." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2023.

"Introduction to Performance-Based Regulation." EUCI Workshop. Virtual. May 2023.

"Introduction to Retail Electricity Regulation for FERC Staff." Federal Energy Regulatory Commission, Office of Energy Market Regulation Training Council. Virtual. February 2023.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. February 2023.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 4, 2022.

"Rate Innovation for Cooperatives and Public Power." EUCI Workshop. Virtual. March 2022.

"Marginal Costs of Electricity Services." EUCI Workshop. Virtual. March 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. February 2022.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Virtual. November 2021.

"Rate Design for Revenue Adequacy and Price Efficiency." Wisconsin Public Utility Institute. *Energy Utility Basics.* October 2, 2021.

"Rate Design and the Potential Impacts of Covid-19." EUCI Workshop. Virtual. November 17, 2020.

"Ratemaking Under Performance-Based Regulation." EUCI Workshop. Atlanta, Georgia. March 9, 2020.

"Load Impact Evaluation: *Base Interruptible Program*." DRMEC Spring Workshop, California Public Utilities Commission. April 26, 2019.

"FERC Regulatory Policy and Relevant Environmental Issues, Focusing on the United States Natural Gas Grid," 2015 Energy Hub Conference. Hosted at the University of Wisconsin-Madison.

COMPUTER/PROGRAMMING SKILLS: Deep knowledge of Excel and STATA for data analysis; experience with R, SAS, and Python for API data acquisition and manipulation.

APPENDIX 3: RESUME OF DANIEL MCLEOD

Daniel McLeod

RESUME

December 2024

Address:

Laurits R. Christensen Associates, Inc.
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Telephone: 608.216.7125
Email: dpmcleod@lrca.com

Academic Background:

PhD, University of Wisconsin-Madison, 2021, Economics
MS, University of Wisconsin-Madison, 2014, Economics
BA, University of Wisconsin-Madison, 2013, Economics

Positions Held:

Economist, Laurits R. Christensen Associates, Inc., July 2021-present

Professional Experience:

As an energy economist, I specialize in incentive regulation. In PBR proceedings, I have calibrated price and revenue caps, performed cost benchmarking studies, quantified financial remedies following a reopener, helped design and evaluate incentive regulation plans more broadly, and sponsored testimony. I have published work in the *Electricity Journal.*

My experience in litigation spans several industries, including poultry, electronics, and telecommunications. I have worked in the areas of economic cost measurement in the airline and railroad industries, and productivity measurement in the postal and electric utility industries.

My academic background is in empirical industrial organization and applied econometrics. My research proposed a novel econometric approach to estimating marginal costs in the airline industry and quantified the impacts of airline mergers using both structural models of the industry and emerging deep learning algorithms. My teaching was in the areas of introductory econometrics and machine learning.

Research Papers:

"Trends and Drivers of Distribution Utility Costs in the United States: A Descriptive Analysis From 2008 to 2022" (with Nick Crowley), *The Electricity Journal,* v. 37 n. 3 (April 2024)

"Structural Estimation in the Airline Industry with Markup Restrictions"

"Cost Sharing During Periods with Low Airline Passenger Demand" (job market paper)

"Predicting the Price Effect of Horizontal Mergers" (with Lorenzo Magnolfi)

APPENDIX 4: RESUME OF XUETING (SHERRY) WANG

Xueting (Sherry) Wang

RESUME

July 2025

Address:

Laurits R. Christensen Associates, Inc.
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Telephone: 608.216.7110
Email: swang@caenergy.com

Academic Background:

Doctor of Philosophy – Columbia University, 2021, Sustainable Development
Master of Public Policy – National University of Singapore, 2014, Public Policy
Bachelor of Science – National University of Singapore, 2011, Chemistry & Political Science

Positions Held:

Economist, Laurits R. Christensen Associates, Inc., Sep 2021-present
Research Assistant, Columbia University, 2018-2021
Teaching Assistant, Columbia University, 2015-2019
Research Assistant, National University of Singapore, 2013-2014

Professional Experience:

I have training in applied econometrics, economic model development and analysis of large datasets. I have applied these skills to assist utilities in evaluating load impacts of demand response programs, load forecasting, developing rate design models and performing bill impact calculations. In my doctoral research, I have developed and estimated a model of consumer product choice in retail electricity markets using a large consumer-level dataset; estimated the competitive effect of wind power using firm-level energy offer curves; estimated the effect of transmission expansion on electricity market dispatch using wholesale market transmission limit and price data. I have used Stata, R, MATLAB, Python, Excel, ENVI, and ArcGIS for economic and statistical analysis. I am a referee for the *Energy Journal*. I have also provided economic analysis for class action lawsuits.

Major Projects

Prepared a report on performance-based regulation.

Estimated load impacts for an automated response technology program.

Estimated heat hump electricity and gas usage for a utility.

Prepared a memorandum evaluating alternative rate designs.

Prepared a report on utility remuneration and performance incentive mechanisms. Prepared a memorandum reviewing the methodology of embedded cost of service study.

Supported density rate design by a natural gas utility.

Developed a rate design model for a municipal utility.

Prepared a memorandum describing the merger of two rate classes.

Prepared a memorandum discussing performance incentive mechanisms.

Calculated cost allocators for a utility rate case application.

Produced long-term load forecast for a utility rate case application.

Calculated customer bill impacts for a utility rate case application.

Estimated load impacts for a residential air conditioning load control program.

Estimated load impacts for a non-residential critical peak pricing program.

Evaluated pricing for a voluntary retail service option.

Calculated electricity rates under an alternative rate design for an electric utility.

Provided economic analysis in antitrust class action of price-fixing.

Provided economic analysis in antitrust class action of no-hire agreement.

Professional Papers

"Performance-Based Regulation Report," for the Maine Public Utility Commission, with Mr. Nicholas Crowley, et al., April 29, 2025.

"2024 Load Impact Evaluation for Pacific Gas & Electric Company's Automated Response Technology Program" with Michael Vigdor, Corey Goodrich, and Michael Ty Clark, 2025.

"2024 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program" with Van Ngo and Andi Romanovs-Malovrh, 2025.

"Jurisdictional Review of Utility Remuneration Models for the Ontario Energy Board" with Nicholas A. Crowley and Andi Romanovs-Malovrh, 2024.

"2023 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates" with Michael Ty Clark, Daniel McLeod, Daniel G. Hansen, 2023.

"2023 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program" with Corey Lott and Andi Romanovs-Malovrh, 2023.

"2022 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates" with Daniel G. Hansen, Michael Ty Clark, and Corey Lott, 2023.

"2022 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program" with Corey Lott, 2023.

"2021 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates" with Daniel G. Hansen, Michael Ty Clark, Corey Lott, and Michael Vigdor, 2022.

"2021 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program" with Corey Lott, 2022.

Conference Presentations

"Introduction to Alternative Regulation." Edison Electric Institute. Hosted at the University of Wisconsin-Madison. July 2025.

"Load Impact Evaluation: *Automated Response Technology program*." DRMEC Load Impact Evaluation and Enrollment Workshop (Virtual) May 2025.

"Cost Allocation and Electricity Rate Design for Data Centers." EUCI's Data Center Project Development, Utilities & Load Growth, Denver, CO, March 2025.

"Load Impact Evaluation: *SmartAC program*." DRMEC Load Impact Evaluation and Enrollment Workshop (Virtual) May 2023.

"Load Impact Evaluation: *SmartAC program*." DRMEC Load Impact Evaluation and Enrollment Workshop (Virtual) May 2022.

"Are Long Term Fixed Rate Contracts Valuable to Consumers? Evidence from Retail Electricity Market." Asian Pacific Industrial Organization Conference. Tokyo, Japan. December 2019.

"How Much Value has Retail Electricity Choice Created?" Heartland Environmental and Resource Economics Workshop. Illinois. September 2019.

"Switching Cost and Deregulation in Retail Electricity Market." 2019 Georgetown Center for Economic Research Biennial Conference. Washington, DC. May 2019.

"The Effect of Transmission Limit on Market Outcome." Empirics and Methods in Economics Conference. Chicago, IL. October 2017.

"Performance Management in the Office of Energy Efficiency and Renewable Energy." American Society for Public Administration Conference. Washington, DC. March 2014

Working Papers

"The Price Effect of Large-Scale Wind Energy."

"Long Term Contracts in Retail Electricity."

"The Effect of Transmission Limit on Market Outcome: Evidence from ERCOT."

Computer/Programming Skills: Deep knowledge of R, MATLAB, and STATA for data analysis; some experience with Python, Excel, ENVI, and ArcGIS.