

# Issues in the Design of a New Ratemaking Framework for OPG's Regulated Hydro-Electric Generating Business

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## Table of Contents

|  |           |
|--|-----------|
| Executive Summary _____                                    | <b>4</b>  |
| The OEB’s Evolving IR Policies _____                       | 4         |
| Stretch Factor _____                                       | 5         |
| Alternatives to Cost Forecasting for Capital Revenue _____ | 5         |
| Productivity Factor _____                                  | 8         |
| Summing Up _____   | 9         |
| <b>1. Introduction .....</b>                               | <b>12</b> |
| <b>2. Incentive Regulation in Ontario.....</b>             | <b>13</b> |
| <b>2.1. The Early Years _____</b>                          | <b>13</b> |
| <b>2.2. Renewed Regulatory Framework _____</b>             | <b>17</b> |
| Price Cap IR _____   | 17        |
| Custom IR _____  | 19        |
| <b>2.3. Subsequent CIR Decisions _____</b>                 | <b>20</b> |
| Horizon Utilities (2014) _____                             | 20        |
| Hydro One Distribution (2015) _____                        | 20        |
| Toronto Hydro (2015) _____                                 | 21        |
| Hydro Ottawa (2015) _____                                  | 22        |
| PowerStream (2016) _____                                   | 23        |
| Hydro One Distribution (2019) _____                        | 23        |
| Toronto Hydro (2019) _____                                 | 24        |
| Hydro Ottawa (2020) _____                                  | 25        |
| Hydro One Networks (2022) _____                            | 26        |
| Toronto Hydro (2024) _____                                 | 27        |
| Hydro Ottawa (2026) _____                                  | 28        |
| Next Generation Rate Framework _____                       | 28        |
| <b>2.4. Summing Up _____</b>                               | <b>29</b> |
| <b>3. OPG's Rate Regulation .....</b>                      | <b>31</b> |

|  |           |
|--|-----------|
| <b>4. Evaluating OPG’s Proposed CIR Framework.....</b>   | <b>35</b> |
| 4.1. Summary of OPG’s Evidence _____   | 35        |
| 4.2. OPG’s Rationale for CIR _____   | 37        |
| <b>5. PEG Critique: Price Cap Index Formula.....</b>   | <b>39</b> |
| 5.1. Stretch Factor _____  | 39        |
| 5.2. Productivity Factor _____   | 39        |
| 5.3. Price Cap Index Design _____  | 40        |
| <b>6. PEG Critique: Reliance on Cost Forecasts .....</b>   | <b>41</b> |
| 6.1. Overview _____  | 41        |
| 6.2. Forecasting Pros and Cons _____   | 41        |
| Forecasting Pro _____  | 41        |
| Forecasting Con _____  | 41        |
| 6.3. Alternative Approaches to Capital Revenue Escalation _____  | 44        |
| Reduce the Share of Any Gap Between Indexed Revenue Growth and Forecasted Capital Cost That is Eligible for Supplemental Revenue _____ | 45        |
| Increase the I-X Growth Applicable to Capital _____  | 46        |
| Reduce the Escalation of OM&A Revenue _____  | 46        |
| Historical Own-Cost Trending _____   | 47        |
| British Remedies _____   | 56        |
| Summing Up _____   | 57        |
| PEG Recommendations _____  | 57        |
| <b>7. PEG Credentials .....</b>  | <b>59</b> |

## Executive Summary

Ontario Power Generation Inc. (“OPG,” or “the Company”) is in EB-2025-0297 proposing a Custom Incentive Rate-Setting (“CIR” or “Custom IR”) framework for its prescribed hydroelectric (“hydro”) generation assets. Following a conventional rebasing of revenue to cost in 2027, the Company’s regulated payment amounts would be escalated in the next four years by a custom price cap index. The index formula that OPG proposes includes the difference between an Inflation Factor (“I”) and an X Factor (“X”) that is the sum of a 0% Productivity Factor and a 0.15% Stretch Factor.

The index formula also includes a Capital Factor (“C”) that would supplement capital revenue growth based on the difference between  $I - X$  and the Company’s forecast of growth in its capital cost less the 0.15% stretch factor. This effectively gives the attrition relief mechanism (“ARM”) a hybrid design in which OM&A revenue is subject to  $I - X$  escalation while capital revenue is escalated primarily on the basis of OPG’s capital cost forecast. A Capacity Refurbishment Variance Account (“CRVA”) applies to eligible projects and would recover capital expenditure (“capex”) overspends, subject to a prudence review, as well as returning underspends to customers. A Gross Hydroelectric Capital Variance Account would ensure that underspends on all other kinds of capex would also be returned to customers.

OEB Staff has retained Pacific Economics Group Research LLC (“PEG”) to appraise key aspects of OPG’s proposed rate framework and empirical research by London Economics International (“LEI”) in support of the framework. This report provides a summary of our work. Details of our empirical research can be found in the Appendix.

### The OEB’s Evolving IR Policies

CIR in Ontario has typically involved ARMs with hybrid designs that entail indexing of the OM&A revenue requirement and heavy reliance on multi-year cost forecasts to escalate capital revenue. Revenue growth for OM&A and capital costs alike has been slowed by a productivity factor based on industry productivity trends and a stretch factor linked to statistical cost benchmarking. Many CIR plans have also featured a clawback of capital cost underspends. OEB panels have on several occasions taken exception to extensive reliance on capital cost forecasts and asked distributors proposing such ARMs to go in a different direction in their next CIR application.

The OEB is considering elements of the Renewed Regulatory Framework (“RRF”) as part of a generic policy review of utility remuneration. However, the OEB has been open to the evolution of approved ARMs in proceedings to approve CIR applications. These innovations can inform subsequent generic deliberations. Some innovations have been proposed by distributors and others by OEB Staff and intervenors.

## Stretch Factor

PEG discusses many concerns about LEI’s cost benchmarking research in the Empirical Appendix. For example, LEI’s work could not be replicated or verified because a non-disclosure agreement prohibited a sharing of work details. Cost during the proposed CIR plan was not benchmarked. PEG also has concerns about many details of LEI’s research methods.

Our own benchmarking research used econometric modelling methods like those typically used in CIR proceedings. We found that OPG’s forecasted total cost would be 7.1% above the prediction of our econometric total cost model during the five years of the proposed CIR plan (2027-2031). Based on this result, we recommend a **0.30%** stretch factor for OPG.

PEG also benchmarked the O&M and capital costs of OPG. This research revealed that a remarkable decline is expected in the Company’s O&M cost performance in 2027, the first year of the plan. This raises concern about strategic cost deferrals that PEG discussed in the recent Spending Pattern Analysis report for OEB staff.<sup>1</sup> OPG’s OM&A revenue has been limited by a rate freeze for several years but nonetheless has not reported an earnings deficiency in these years.

## Alternatives to Cost Forecasting for Capital Revenue

The prominent role that capital cost forecasting plays in CIR has long been criticized by intervenors and witnesses for OEB Staff. Concerns include weakened capex containment incentives and the high regulatory cost, uncertainty, and risks to customers when appraising the reasonableness of utility capex forecasts. Incentives to contain capex and OM&A expenses are imbalanced. We showed in recent testimony for OEB Staff in the Alectra Utilities CIR proceeding that the Total Factor Productivity

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<sup>1</sup> Lowry, Mark N., David Hovde, Matt Makos, and Rebecca Kavan, “Report on Spending Patterns and Capitalization Policy,” in EB-2025-0108, OEB Staff Report, January 8, 2026.

("TFP") trend of larger Ontario distributors that typically operate under CIR has been slower than that of the industry as a whole, and declining capital productivity is the biggest problem.

This report discusses various alternatives to the standard CIR approach. These include penalties for poor capital cost forecasting, supplemental capital stretch factors, a mechanistic sharing of differences between I-X and forecasted capital cost growth. Supplemental capital stretch factors have ample precedent in Ontario CIR, as shown in the following table.

| <b>Company</b>     | <b>Service</b>     | <b>Case Number</b> | <b>Approved Supplemental Stretch Factor on Capital</b> |
|--------------------|--------------------|--------------------|--|
| Hydro One Networks | Power distribution | EB-2017-0049       | 0.15%  |
| Toronto Hydro      | Power distribution | EB-2018-0165       | 0.3%   |
| Hydro One Networks | Power transmission | EB-2019-0082       | 0.15%  |
| Hydro Ottawa       | Power distribution | EB-2019-0261       | 0.15%  |
| Hydro One Networks | Power distribution | EB-2021-0110       | 0.20%  |
| Hydro One Networks | Power transmission | EB-2021-0110       | 0.20%  |
| Toronto Hydro      | Power distribution | EB-2023-0195       | 0.3%   |
| Hydro Ottawa       | Power distribution | EB-2024-0115       | 0.225%   |

Arguments favoring supplemental capital stretch factors (and the sharing mechanism alternative) include the need

- for a materiality condition in determining eligibility for supplemental capital revenue;
- to at least match the "dead zone" in the OEB's incremental and advanced capital modules;
- to protect customers from information asymmetries; and
- to strengthen capex containment incentives and avoid imbalanced incentives for OM&A and capital cost containment.

The forecasting approach to ARM design has been used by multiyear rate plan practitioners that include Great Britain, New York, and Minnesota. However, other practitioners have balked at relying heavily on cost forecasts for ARM design. In addition to indexing the OM&A revenue requirement, some

of these regulators have relied on historical own-cost trending of capital cost. This approach, which is used in Alberta, California, and Massachusetts, can entail fixing budgets for many kinds of plant additions in the out years of a rate plan on the utility's recent average historical plant additions, with possible escalation for construction cost inflation and growth in operating scale. In Alberta and Massachusetts, this approach has been labeled the "K-bar" approach.

We developed a straw man alternative ratemaking treatment of capital wherein we separate OPG's proposed capital projects into those that would be addressed by forecasts and/or deferral and variance accounts and others that would be addressed by historical own-cost trending. We generally avoided own-cost trending for asset categories where capex growth was either expected to accelerate markedly or to be highly uncertain. For asset categories that we recommend addressing with trending, we calculated the average plant additions over the five-year 2022-2026 period as adjusted to 2027 dollar and output levels. For each of the "out" years of the proposed CIR term (2028-2031), we escalated the capex averages from 2027 levels to the applicable years based on the growth in input prices and operating scale. Escalation for operating scale relied on forecasted growth in capacity based on the maximum continuous rating, in MW. The inflation-adjusted historical average capex deemed prudent that we nominate for this treatment is less than the Company's proposed capex in these years by approximately 11%. Our straw man approach does not entail calculation of a specific K-bar term and can dovetail with the general CPCI approach that OPG has proposed. Capital revenue growth would still be slowed by the stretch factor and capital productivity factor (if positive).

PEG acknowledges that strong evidence on how K-bar would work has not been produced in this proceeding due in part to an unwillingness by OPG to provide certain requested information. We also acknowledge that OPG may need an unusual surge in capex during its plan. PEG therefore instead recommends that the panel choose between two alternative ratemaking treatments of capital.

- a) A 0.3% supplemental capital stretch factor.
- b) Share the difference mechanistically between the capital revenue growth yielded by the index and the growth yielded by a capital cost forecast.

Formulas for both of these approaches can be found in Section 2.1 of the Appendix.

PEG also encourages the panel to consider a British-style penalty if it finds OPG's capital cost forecasting to be inadequate. Such a penalty could take the form of a capital stretch factor supplement between 0 and 10 basis points.

## **Productivity Factor**

PEG has many concerns about LEI's productivity research, and these concerns are discussed at length in the Appendix. Our own research for OEB Staff found the TFP growth of a sample of U.S. hydroelectric generators to average a 0.47% annual decline over the fifteen most recent growth rate years for which data were available.

PEG has occasionally proposed a negative productivity factor in OEB proceedings and this is a good proceeding to restate reasons that it can make sense when there is strong evidence of declining industry productivity that is driven by external business conditions. Productivity is not a pure measure of cost efficiency and can reflect mounting external cost pressures such as an increase in the share of capacity that is quite aged.

In an application to OPG, a negative productivity factor would increase OM&A revenue escalation but capital revenue escalation would be unaffected using the formula that we set forth in Appendix Section 2.1. That is because a non-negativity restriction would sensibly prohibit use of a negative productivity factor to accelerate growth in a revenue requirement that is based on a forecast. The negative productivity factor would however cause the C factor to fall. OPG would have no legitimate complaint about an implicit stretch factor.

Based on this reasoning PEG believes that a **-0.47%** Productivity Factor can make sense for OPG if it is combined with our recommendations for a **0.30%** stretch factor and a **0.30%** supplemental capital stretch factor. Consumers would then benefit on balance since capital revenue is much larger than OM&A revenue. Should the panel choose not to approve a negative productivity factor, it may reason that OPG may have considered the problem of an implicit stretch factor in proposing a marked increase in its OM&A expenses in 2027 to be followed by I-X escalation.

## Summing Up

PEG’s recommendations to the panel regarding the Company’s CIR plan are summarized in the following table. These recommendations are made for this rate proceeding and are not intended to apply to future proceedings.

### Comparison of OPG and PEG’s Proposed Ratemaking Frameworks

| Ratemaking Provision        | OPG Proposal  | PEG Proposal  |
|-----------------------------|---|---|
| Year 1 / “Going-In” Rates   | Standard cost of service rebasing based on 2027 test year   | Same  |
| Form                        | Custom Price-cap Index  | Price cap approach makes sense but productivity factor research should be based on capacity, not volume. An output differential is then needed in the formula but this can reasonably be set at zero for OPG. |
| Coverage                    | Comprehensive (capital and OM&A)  | Same  |
| Annual Adjustment Mechanism | $1+(I-X+C-GRCF)$  | Same <i>general</i> formula but the negative industry productivity trend would reduce and not increase the C factor.  |
| Inflation                   | Composite Index.<br>Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour Index (GDP-IPI-FDD Canada) | Same  |
| X Factor                    | Productivity Factor = 0%<br>Stretch Factor = 0.15%  | Productivity Factor = -0.47% but only escalates OM&A revenue.<br>Negative Productivity factors should not be added to capital cost forecasts.<br>Stretch Factor = 0.30%                                       |



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| <p><b>C Factor</b></p>   | <p>Difference between forecasted growth rates of capital cost and I-X less stretch factor</p> <p>Stretch Factor Capital Related Revenue Requirement Adjustment: 0.15%</p>  | <p>Difference between forecasted growth rates of capital cost and I-X</p> <ul style="list-style-type: none"> <li>• less a 0.30% stretch factor</li> <li>• less a supplemental capital stretch factor of 0.3%.</li> </ul> <p>The panel should also consider using historical own- cost trending for a portion of the capital revenue requirement. This would replace forecasting for part of the capital revenue requirement and could work with the C factor. There would be no capital underspend clawback on this capex.</p> <p>The panel should also consider adding to the supplemental capital stretch factor a penalty between 0 and 0.10% if OPG’s capital cost forecast is deemed insufficient.</p> |
| <p><b>Capacity Refurbishment Variance Account (“CRVA”)</b></p> | <p>Reference amounts determined for each year of the IR term based on forecast CRVA-eligible projects, to be reviewed on a five-year cumulative basis.</p> <p>Recovery subject to total capital-related revenue requirement exceeding capital funding available through payment amounts inclusive of C-factor (see interaction with GHCVA)</p> | <p>Consider mechanistic sharing of variances from forecasts</p>   |
| <p><b>Global Hydroelectric Capital Variance Account</b></p>    | <p>Records the difference, for the 2028-2031 period and asymmetrically in favour of ratepayers, between</p> <p>(i) the forecast capital-related revenue requirement (“CRRR”)</p>   | <p>Consider mechanistic sharing of underspends.</p>   |



|  |  |                    |
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|  | <p>that forms the basis of the C-factor, and</p> <p>(ii) the CRRR determined based on OPG’s actual capital in-service additions for the prescribed hydroelectric facilities over the 2028-2031 period</p>  |                    |
| <p><b>Earnings Sharing and Off-ramps</b></p> | <p>A regulatory review may be initiated if OPG’s annual reporting shows performance for OPG’s combined regulated nuclear and regulated hydroelectric operations outside of the <math>\pm 300</math> basis point ROE dead band, or if performance erodes to unacceptable measures.</p> <p>Earnings sharing mechanism shares 50% of any regulated earnings for OPG’s combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative 5-year period.</p> | <p>No Position</p> |



# 1. Introduction

Ontario Energy Board (“OEB”) proceeding EB-2025-0297 concerns an application by Ontario Power Generation Inc. (“OPG,” or “the Company”) to rebase its rates for rate-regulated generation, establish a new Custom Incentive Rate-Setting (“CIR” or “Custom IR”) framework for the regulated hydro-electric generation, and continue the separate CIR framework for the nuclear generation business. Incentive ratemaking (“IR”) is called performance-based ratemaking or “PBR” in some jurisdictions. The Company’s proposed framework is a multiyear rate plan (“MRP”) that would cover the five years from 2027 to 2031. The plan has an ARM for rates for generation from designated hydroelectric (“hydro”) facilities that takes the form of a Custom Price Cap Index (“CPCI”). London Economics International (“LEI”) has provided supportive statistical cost research for the proposal.

Pacific Economics Group Research LLC (“PEG”) has for many years been one of North America’s leading consultancies on the design of IR plans. We have played a prominent role in the development of IR in Ontario, Alberta, and several other North American jurisdictions. OEB Staff retained PEG to provide an independent appraisal and commentary on OPG’s CIR evidence. The goal is to assist the OEB in selecting an appropriate CIR plan for OPG, not to change the general approach to CIR in Ontario.

This report presents our analysis of other features of the proposed CIR framework. Section 2 discusses the evolution of the OEB’s ARM design policies and implications for OPG’s next plan. Section 3 reviews the history of OPG’s ratemaking, while Section 4 outlines OPG’s new CIR proposal and briefly considers OPG’s case for a new approach to IR. In Section 5 we critique the CPCI. Section 6 discusses the heavy reliance on cost forecasting for capital revenue escalation and considers alternative approaches. A brief discussion of PEG’s credentials is provided in Section 7. The views expressed in these reports are those of the author. LEI’s proposed productivity factor and stretch factor and supportive evidence and PEG’s alternative studies are discussed in the attached Empirical Appendix.

## 2. Incentive Regulation in Ontario

In this section we present a high-level review of OEB incentive ratemaking policies that have a notable bearing on OPG's CIR proposal. The focus is on the design of the ARM that escalates rates between rebasings. Statements of particular relevance to the OPG proposal are boldfaced in this review.

### 2.1. The Early Years

Rates of Ontario power distributors were for many years regulated by Ontario Hydro. The OEB approved its first-generation generic incentive ratemaking mechanism ("1<sup>st</sup> GIRM") for provincial power distributors for an initial 2000-2002 term. This mechanism was an MRP featuring a price cap index with an I-X formula and an earnings sharing mechanism ("ESM"). The OEB subsequently delayed implementation of the 1<sup>st</sup> GIRM to 2001 and removed the ESM. The 1<sup>st</sup> GIRM was later extended to March 2005 to afford distributors more time to "explore the incentives for improvements and savings provided by the current PBR regime." However, Bill 210, enacted in December 2002, froze existing distributor rates until May 2006 unless approval was otherwise granted by the Minister of Energy. Rate rebasing applications were filed in 2005 and decided in early 2006.

Between 1999 and 2006, it follows that Ontario power distributors operated without a rebasing or ESM. During these years, distributors had strong incentives to contain costs, and some may have responded by deferring some capital expenditures. This encouraged some deferring distributors to seek extra funding for capex in later years.

The 2<sup>nd</sup> GIRM used 2006 rates as a starting point. The OEB introduced staggered plan terms allowing approximately 1/3 of distributors to rebase rates each year between 2008 and 2010.<sup>2</sup> Utilities had up to 5 years on a new price cap index.

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<sup>2</sup> Due to the staggered nature of rate reviews, a handful of utilities were on 2<sup>nd</sup> IRM as late as 2011.

The 3<sup>rd</sup> GIRM also featured a price cap index, and its term was initially fixed at four years.<sup>3</sup> In a subsequent letter, the OEB discussed its expectations that distributors would not rebase rates prior to the end of the plan term.

The Board's rate-setting policies are such that distributors are expected to be able to adequately manage their resources and financial needs during the term of their IRM plan. The Board's multi-year rate setting approach does contemplate that some distributors may legitimately need to have their rates rebased earlier than originally scheduled, by making provision for an "off-ramp."<sup>4</sup>

Toronto Hydro ("THESL") nonetheless obtained rebasings of its rates for 2008, 2010, and 2011.<sup>5</sup> In its 2008 rebasing proceeding, that company initially requested approval of an MRP based entirely on cost forecasts. This was rejected by the OEB on several grounds.

In the Board's opinion, the Applicant's proposal does not meet a number of the key elements of its multi-year rate setting plan. First, multi-year regulation seeks to balance ratepayer and shareholder interests through the imposition of **explicit productivity goals**. This means that the multi-year plan should encourage productivity improvements within the Utility, and should ultimately share those gains with the ratepayers. In the Board's plan, this is accomplished through the use of an **offsetting productivity factor (the X-factor)**, which **provides a sharing of the benefit of efficiency gains to ratepayers immediately**. The Board simply could not see any discernable productivity driver within the Applicant's proposal. That is not to say that the Applicant is not concerned about productivity, but simply that there is no transparent reflection in its multi-year rate plan that addresses the issue. The Applicant's plan contains steady increases in spending in each of the three years, but there is **no explicit or measurable incentive to productivity**, nor any mechanism which would capture such gains in any year over the period.

Second, multi-year regulation should provide for a timely review of the extent to which the company is performing to its forecasts. Under the Applicant's proposal **there appears to be no check as to the accuracy of its forecasts** until the year following the last year of its program; namely, 2011. While this is not problematic under the Board's plan where rates based on one year's forecast are subject to a formulaic adjustment which includes the productivity incentive, here the Applicant has based its proposal on forecasts, each dependent in some measure on the

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<sup>3</sup> Some companies operated under 3<sup>rd</sup> GIRM as early as 2009, depending upon when their rate rebasing occurred.

<sup>4</sup> Ontario Energy Board, "April 20, 2010 Letter to All Licensed Electricity Distributors Re: Early Rebasing Applications," pp. 1-2.

<sup>5</sup> THESL initially requested three fully forecasted test years for rate years 2008-2010 based on forecasts. The OEB rejected this proposal, instead approving 2008 and 2009 rates based on cost forecasts.

previous year's forecast, with the result that **each additional year's forecast is subject to increasing uncertainty.**<sup>6</sup>

In this proceeding, the OEB ultimately approved rates for two forward test years (2008 and 2009) on the basis of cost forecasts. The issue of whether THESL should be required to operate under 3<sup>rd</sup> GIRM was discussed in subsequent applications. In a 2011 rate case decision, the OEB stated that THESL had made a "choice to approach the Board's ratemaking processes in a manner that is contrary to the Board's rate setting policies."<sup>7</sup> The OEB continued:

In order to justify its approach, THESL posits that two separate frameworks exist and that it has been operating within one of them, that being a cost of service framework. THESL argues that it would be inappropriate for the Board to now treat it as though it were operating within the other framework, that being an IRM framework. . .

The Board's rate setting policies are not composed of the two separate frameworks that THESL describes. As stated above, the Board has clearly articulated the mechanics of the multi-year rate setting plan and its expectations of distributors. . .

THESL has pointed to situations in which the Board's multi-year rate setting plan has not been strictly adhered to in support of its position that its view of the framework is one that the Board should accept. While the Board accepts that there have been deviations from the Board's stated multi-year rate setting plan, including the acceptance of THESL's non-conforming applications in the past, the Board considers the April 20, 2010 letter to be a clear and explicit statement of the Board's expectations of distributors on a going forward basis...<sup>8</sup>

**A THESL application for an MRP with an ARM based on forecasts for the 2012-2014 period was dismissed at the preliminary issue stage.**<sup>9</sup> Instead, THESL's rates for those years were set according to the provisions of 3<sup>rd</sup> GIRM.

No special ratemaking provisions for capital were discussed in the OEB's 1<sup>st</sup> GIRM decision. In the proceeding to approve 2<sup>nd</sup> GIRM, a Hydro One Networks, Inc. ("Hydro One") witness proposed a Capital Investment ("CI") Factor for supplemental capital revenue that would have functioned much like the C-factors approved in later years. This proposal was rejected due to a lack of perceived need, but

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<sup>6</sup> Ontario Energy Board (2008), May 15, 2008, Decision in EB-2007-0680, pp. 4-5.

<sup>7</sup> Ontario Energy Board (2011), *Partial Decision and Order* in EB-2010-0142, July 7, p. 8.

<sup>8</sup> *Ibid*, pp. 9-10.

<sup>9</sup> Ontario Energy Board (2012), Decision With Reasons and Order on the Preliminary Issue, January 5, p. 18.

distributors were permitted to file a rate case early. The OEB expressed concerns about special ratemaking provisions for capital in its decision.

In a capital-intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. **The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.**<sup>10</sup>

Supplemental capital funding in the 2<sup>nd</sup> GIRM was limited to a funding adder related to smart meters.<sup>11</sup> A true up between revenues received through this adder and actual revenue requirements resulting from smart meter implementation would occur at a later time. Recovery of a distributor's actual smart metering costs was not permitted until the costs had been reviewed for prudence.

The 3<sup>rd</sup> GIRM contained a supplemental revenue mechanism for capital called the Incremental Capital Module ("ICM"). The OEB described the ICM in its decision as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."<sup>12</sup> The OEB set a high bar for ICM approval as amounts were required to exceed a materiality threshold, meet three need criteria, and be prudent. The materiality threshold was determined formulaically and was intended to be a level of total plant additions materially higher than that funded by the price cap index, depreciation, and growth in billing determinants. The "dead zone" in which extra capital cost was ineligible for supplemental revenue was initially fairly wide. Smart meter riders also continued during the 3<sup>rd</sup> GIRM.

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<sup>10</sup> Ontario Energy Board, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 37. Filed December 20, 2006.

<sup>11</sup> A funding adder was effectively a rate rider that allowed the distributor to recover additional revenues. These revenues would address costs resulting from smart metering activities.

<sup>12</sup> Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 31. Filed September 17, 2008, in EB-2007-0673.

## 2.2. Renewed Regulatory Framework

The RRF that is currently used in Ontario ratemaking resulted from initiatives the OEB began in 2010 to review their policies on ratemaking, distribution system planning, and performance measurement. At an early stage of the RRF proceeding, the OEB 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.”<sup>13</sup>

In an early presentation to stakeholders, OEB Staff provided an overview of the RRF proceedings, its objectives, and guiding concepts. While regulatory cost was not treated as an objective of the RRF, it was discussed as one of its guiding concepts.

Regulatory frameworks should be sustainable. And, in practice, a framework should be predictable and understood by stakeholders, and **capable of being implemented through efficient & effective regulatory processes.**<sup>14</sup>

Three kinds of MRPs are available to distributors under the RRF: a fourth generation of generic IR (now called “Price Cap IR” or 4<sup>th</sup> GIRM), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach.<sup>15</sup> Distributors are also required to periodically file distribution system plans (“DSPs”) and most do so with their rebasing.

### Price Cap IR

Under price cap IR, rates in the later years of a plan are escalated by an I – X formula where I is an inflation factor that is calculated as a weighted average of the growth rates of the average weekly earnings of all employees in Ontario and Canada’s gross domestic product implicit price index for final domestic demand. The weights for these two indexes were the typical shares of direct labor OM&A

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<sup>13</sup> Ontario Energy Board, *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, filed in OEB Case EB-2010-0379, November 8, 2011, p. 1.

<sup>14</sup> Ontario Energy Board Staff, “Stakeholder Conference on Development of a Renewed Regulatory Framework: Board Staff Presentation on Staff’s Approach to the Consultation and the Issues,” February 2, 2011, filed in OEB Case 2010-0377, slide 9.

<sup>15</sup> Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012.

expenses and other costs in the total cost of the base rate inputs of medium and large distributors. These shares are 30% for labor and 70% for other costs.

An Advanced Capital Module (“ACM”) was developed subsequent to the development of the RRF 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. ACMs are generally very similar to ICMs, the key difference being that ACMs can only be requested at rebasing, while ICMs are now only available for capex that was unforeseen at rebasing or for distribution system plan capex that was significantly higher than forecasted. The OEB in its decision discussed the advantages of the ACM.

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

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.<sup>16</sup> [Emphasis added]

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<sup>16</sup> 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.

In its decision to implement an ACM option, the OEB reduced the dead zone for ACMs and ICMs alike, limited the scope of ICMs, and added a means test to prevent capital module requests from distributors that are overearning by more than 300 basis points.

## Custom IR

In the OEB's RRF Report of the Board, Custom IR was described as an approach to ratemaking in which 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."<sup>17</sup> 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."<sup>18</sup>

The OEB's Rate Handbook provides the following additional guidance for utilities requesting CIR.<sup>19</sup>

**The annual rate adjustment must be based on a *custom index* supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; *explicit financial incentives* for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, *must be incorporated through a custom index or an explicit revenue reduction over the term of the plan* (not built into the cost forecast).**

**The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. *If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.*** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

**It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to**

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<sup>17</sup> OEB, Renewed Regulatory Framework, op. cit., p. 13.

<sup>18</sup> *Ibid.*, p. 19.

<sup>19</sup> OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

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.<sup>20</sup> [Emphasis added]

## 2.3. Subsequent CIR Decisions

### Horizon Utilities (2014)

Horizon Utilities was the first power distributor to receive approval of a CIR plan. This plan was outlined in a settlement. The budget for OM&A was informed by parties' estimates of inflation, growth, productivity, and a stretch factor. Capital costs were also forecast, and a variance account was established to return capital revenue requirement underspends due to underspending on plant additions to customers. An asymmetric ESM provided customers with a 50% share of all overearnings, while a targeted performance incentive mechanism ("PIM") was established to penalize the company if its cost performance deteriorated sufficiently to move them out of their current stretch factor cohort in the OEB's annual benchmarking studies.<sup>21</sup> During the course of this plan, Horizon merged with Enersource Hydro Mississauga and PowerStream, creating Alectra Utilities.

### Hydro One Distribution (2015)

In 2013 Hydro One requested a 5-year CIR plan with an ARM that Hydro One described as based on a "forecast cost of service,"<sup>22</sup> the OEB approved only three years and stated the following.

**Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.**

Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behavior similar to that seen in commercially-oriented, consumer market-driven companies. **Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's**

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<sup>20</sup> *Ibid.*, pp. 25-26.

<sup>21</sup> CIR plans have fixed the productivity and stretch factor values during the term of the plan.

<sup>22</sup> EB-2013-0416, Exhibit C1, Tab 1, Schedule 1, p. 1.

**own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation....**

**The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are *external to the company*.** The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.

**The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company.** Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.<sup>23</sup> [emphasis added]

It is notable that the OEB questioned the incentive power of a forecasted ARM.

## **Toronto Hydro (2015)**

In 2015, the OEB approved a CIR plan for Toronto Hydro<sup>24</sup> that included several provisions used in several subsequent plans. The approved plan had a nearly 5-year term and a hybrid ARM design achieved by adding a custom capital ("C") factor to a price cap index formula. The C factor ensured capital revenue growth equal to the approved forecast of capital cost growth, less the sum of a 0% productivity factor and a stretch factor linked to total cost benchmarking. The mathematical formula for the C factor was reasonable but not intuitive. A symmetrical ESM addressed non-capital related earnings variances outside of a 100-basis point dead band. A variance account refunded the entirety of any capital cost underspends to customers. The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the plan IR term without specifying which proposed components were disallowed.

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

Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. . . **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests.**<sup>25</sup> [Emphasis added]

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<sup>23</sup> Ontario Energy Board, *Decision*, EB-2013-0416/EB-2014-0247, March 12, 2015, pp. 13-14.

<sup>24</sup> EB-2014-0116

<sup>25</sup> *Ibid.*, p. 4.

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

[a] Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.<sup>26</sup>

The OEB also commented on the challenge of processing THESL's application, which included multi-year capital cost forecasts.

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 . . . which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.**<sup>27</sup>

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

## Hydro Ottawa (2015)

In 2015 Hydro Ottawa obtained approval of a CIR plan that was outlined in a settlement. The ARM was a revenue cap with a hybrid design. After rebasing, the OM&A revenue requirement was escalated based on a forecast of inflation minus X (combined productivity/stretch factor) plus forecasted growth in operating scale. The OM&A escalator was updated for the last two years of the plan to reflect new inflation data. The capital revenue requirement was based on a forecasted rate base for each year without adjustment for productivity or stretch factors.

Variance accounts were instituted to refund cumulative capital cost underspends to customers due to capital additions that were less than forecast. There were two accounts created to address the

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<sup>26</sup> *Ibid.*, p. 5.

<sup>27</sup> OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

costs of the new operating centers and administrative facilities. The first addressed costs up to a cap, which the OEB had determined to be prudent. The second addressed costs above that cap, which would be addressed in the next rate rebasing. A penalty-only PIM was established that would penalize the company if its cost performance deteriorated during the plan term, as measured by annual benchmarking studies provided by PEG.

### **PowerStream (2016)**

The OEB rejected a CIR proposal for PowerStream in EB-2015-0003. This proposal featured forecasts of OM&A expenses and capital cost for the entire 5-year plan term. OM&A expenses would only be adjusted for inflation if the OEB's inflation factor was more than 200 basis points higher than the inflation assumption in PowerStream's budget. The OEB provided a lengthy list of its concerns with PowerStream's CIR proposal in its rejection.

PowerStream's approach to determining its customers' needs and establishing its future revenue requirement is not likely to result in advancing the OEB's policy objectives as set out in the RRF... over the five-year period of the application. PowerStream has not embedded financial incentives for continuous productivity improvement into its revenue requirement calculation or internal benchmarking that tracks year over year continuous productivity improvement. It has also not demonstrated sufficiently that its proposed increased capital investment levels will bring value to its customers and has not engaged customers in a way that provides useful input into the development of its business plans.<sup>28</sup>

### **Hydro One Distribution (2019)**

The OEB approved its first CIR plan for Hydro One Distribution in EB-2017-0049. This plan featured a revenue cap index formula with a C factor and a clawback of capital cost underspending. A growth factor was not included in the formula.

This decision also revealed a wariness on the part of the OEB with respect to multi-year capex forecasts and the related C factor. The OEB disallowed \$300 million (about 8.4%) of Hydro One Distribution's capex forecast. The OEB also adopted an **incremental capital stretch factor** of 0.15% that applied solely to the C-factor beyond the 0% productivity factor and the 0.45% stretch factor that

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<sup>28</sup> Ontario Energy Board (2016), "Decision and Order EB-2015-0003 PowerStream Inc. Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020," p. 3.

applied to the entire revenue requirement and was informed by econometric benchmarking research.<sup>29</sup> This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."<sup>30</sup> The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness (PEG) that the C-Factor and clawback of capex underspends led to imbalanced incentives to contain capex and OM&A expenses.<sup>31</sup>

In accepting Hydro One's revenue cap approach to ARM design, the OEB stated that

Under the Custom IR option, it is open to a utility to propose options as long as all requirements of the Custom IR framework have been met. It is, by its own definition, a custom approach to rate-setting.<sup>32</sup>

### **Toronto Hydro (2019)**

In 2019 the OEB approved another CIR plan for THESL that applied to the 2020-2024 period. This plan was broadly similar to that company's prior plan. The ARM took the form of a custom price cap index with an  $I - X + C - G$  formula, where  $I$  was the OEB-approved inflation factor for power distributors;  $X$  was the sum of a 0% productivity trend and a 0.60% stretch factor based on benchmarking evidence;  $C$  caused capital revenue to reflect the growth in the forecasted capital-related revenue requirement index reduced by both the  $X$  factor and an **incremental capital stretch factor** of 0.3%; and  $G$  is the growth in revenues from forecasted growth in load and the number of customers during the Custom IR term. To make this a price cap index,  $G$  was subtracted from this formula. Other features of the plan included an asymmetrical ESM for overearnings, a refund of capital underspends, and a symmetrical variance account for externally-driven capital.

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<sup>29</sup> These incremental capital stretch factors have gone by different names for each distributor that has had them approved. For simplicity, we will use the term incremental capital stretch factor.

<sup>30</sup> OEB, Decision and Order, EB-2017-0049, March 7, 2019, p. 32.

<sup>31</sup> *Ibid.*, p. 32-33

<sup>32</sup> *Ibid.* p. 24.

During the proceeding, parties questioned the need for Toronto Hydro to continue using Custom IR to determine rates and the incentive properties of Toronto Hydro's Custom IR plan framework. For example, in OEB Staff's view, Toronto Hydro's custom price cap index was nearly a multi-year cost of service and that it lacked a sufficient productivity incentive.

In its decision, the OEB expressed concerns about Toronto Hydro's approach to Custom IR.

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 does not agree that the proposed Custom IR framework provides the benefits to ratepayers suggested by Toronto Hydro compared to a standard IRM application....

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.**<sup>33</sup> (emphasis added)

The OEB also discussed the need to add an incremental capital stretch factor.

The OEB accepts a C-factor but requires an incremental stretch factor on capital of 0.3% be applied. It is a fundamental component of the OEB's RRF that utilities must demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. In addition, the OEB notes that pacing and prioritization is an important aspect of an efficient capital plan.<sup>34</sup>

## Hydro Ottawa (2020)

A second-generation CIR plan was approved for Hydro Ottawa in 2020. The terms of this plan were outlined in an OEB-approved settlement. The ARM has once again been a hybrid revenue cap. OM&A escalation has been based on a revenue cap index with an  $I - X + G$  formula. Here  $I$  was the

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<sup>33</sup> Ontario Energy Board, Decision and Order EB-2018-0165 Toronto Hydro-Electric System Limited, December 19, 2019, pp. 23-24.

<sup>34</sup> *Ibid.* pp. 40-41.

standard OEB inflation factor, updated annually.  $X$  was the sum of a 0% productivity factor and a 0.45% stretch factor. The growth factor  $G$  was 35% of the forecasted growth in customers during the plan term. The  $I$  factor was updated each year while the  $X$  and  $G$  factors have been fixed for the plan term. The capital revenue requirement has once again been based on a cost forecast, but capital revenue requirement growth has been reduced by the  $X$  factor and an incremental capital stretch factor of 0.15%.

Variance accounts refund to customers the capital revenue requirement from any capital addition underspends for most kinds of capex, while capital additions associated with third party requested relocations or residential service expansions have been subject to symmetrical reconciliation. The variance account for contributions made to Hydro One for transmission investments was retained. A variance account to address certain cloud computing costs was adopted. The ESM asymmetrically shares only surplus earnings. Penalty-only PIMs were established for system reliability and the unit cost performance for wood pole and underground cable replacement investments (e.g., if the cost per wood pole replaced exceeds a target, Hydro Ottawa must pay a penalty).

In its decision approving the plan, the OEB expressed a concern about Hydro Ottawa coming in repeatedly with requests for CIR plans. The OEB stated that “any future Custom IR application needs to be justified and **the OEB needs to be satisfied that other rate-setting options have been considered.**”<sup>35</sup>

## Hydro One Networks (2022)

In 2022 the OEB approved a second-generation CIR plan for Hydro One Networks.<sup>36</sup> The plan was outlined in a settlement amongst parties that provided base rate escalation using the growth in a revenue cap index with an  $I - X + C$  formula.<sup>37</sup> The  $C$  factor continues to be informed by a forecast of

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<sup>35</sup> OEB, Decision and Order in EB-2019-0261, November 19, 2020, p. 12.

<sup>36</sup> A second-generation CIR plan was also approved for Hydro One Networks’ transmission in 2022. This discussion focuses solely on the distribution plan that resulted.

<sup>37</sup> Decisions where the OEB approved a settlement have featured relatively few discussions about whether a CIR framework is appropriate.

capital cost growth that is adjusted for agreed to reductions (12.2% reduction of capex from Hydro One's original proposal) and an **incremental capital stretch factor** of 0.2%.

There were several noteworthy differences in this plan. For example, the C-factor is updated annually to reflect the latest actual inflation (e.g., the company included a placeholder of inflation that is subsequently updated in annual filings). The clawback of capital cost underspends was not retained. Variance accounts address the costs of second-generation AMI deployment, facility relocations, and some customer-requested distributed energy resource ("DER") upgrades and connections.

Notably, the settlement included a requirement for Hydro One as part of its next rebasing proceeding to **"consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year**, while meeting OEB Renewed Regulatory Framework ... objectives and striking an **appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.**"<sup>38</sup>

## Toronto Hydro (2024)

The OEB approved a third-generation CIR plan for Toronto Hydro in 2024. This plan features a Custom Revenue Cap Index with an *Inflation – X + Revenue Growth Factor* ("RGF") formula. The RGF effectively results in a hybrid revenue cap design. In years after the rebasing the OM&A revenue requirement is escalated by the standard OEB inflation factor for power distributors less X plus a 0.41% growth factor (G). Growth of the capital revenue requirement is based on a forecast of *real* capital cost growth that is escalated for inflation and reduced by the X factor. The new plan features a revenue decoupling mechanism where forecasted load growth is trued up to actuals, but only when this favours customers. The variance account that refunded capital underspends to customers in the prior plan has been discontinued. New variance accounts address capital costs of certain DER, load growth, and externally-initiated plant relocation and expansion projects. There is a symmetrical variance account for costs of non-wires solutions.

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<sup>38</sup> OEB, Settlement Proposal in EB-2021-0110, October 24, 2022, pp. 26-27.

## Hydro Ottawa (2026)

Hydro Ottawa has received approval of a 3<sup>rd</sup> generation CIR plan for the 2026-2030 period. A rebasing will set rates for the first year of the plan. The ARM once again takes the form of a hybrid revenue cap, with the OM&A revenue requirement updated annually by an index with an  $I - X + G$  formula. The capital revenue requirement is based on a forecast, reduced from the company's proposal and adjusted to reflect a stretch factor and an incremental capital stretch factor.<sup>39</sup> The  $X$  and  $G$  terms of the OM&A revenue cap are fixed for the term of the plan, while the inflation factor is updated annually.

Symmetrical variance accounts will address the costs of non-wires solutions projects net of any external funding, transmission contributions to Hydro One Networks, and capex for plant relocations, residential subdivisions, and new commercial developments. The previously effective variance account to refund the revenue requirement impact of capital underspends for most kinds of capital projects was discontinued.

The parameters of the ESM are dependent on the company's performance in annual benchmarking studies. If Hydro Ottawa is in cohort 5 (e.g., one of the worst performers in Ontario), the ESM will share all overearnings equally with customers. If Hydro Ottawa is in any other cohort, earnings sharing will begin once earnings exceed 150 basis points above the allowed ROE.

## Next Generation Rate Framework

In January 2026 the OEB opened a policy consultation to update the rate-setting framework for electricity distributors. The OEB's proposed scope for this consultation includes updates to the total cost benchmarking and total factor productivity studies; incorporating PIMs into the rate-setting framework; consideration of refinements to the three available rate-setting methodologies "to strengthen incentives, level the playing field for solutions, share risk, and/or mitigate risk due to

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<sup>39</sup> In theory, the stretch factors for OM&A and capital revenues could differ. However, this was not the case in this proceeding.

uncertainty”<sup>40</sup>; and to consider alternative approaches for setting the revenue requirement. The OEB considers that this will be a refresh of the existing rate framework rather than a radical redesign of it.

## 2.4. Summing Up

This review of the OEB’s ARM design policies has several implications for the OPG proceeding.

- CIR has typically involved hybrid ARM designs in which the revenue requirements for OM&A and capital have different escalators in the years following the rebasing year. Effectively, the OM&A revenue requirement has been escalated by an index while escalation of the capital revenue requirement has mainly been based on multi-year capital cost forecasts.
- The OEB’s recommendations of a “custom index” and external productivity growth offsets in ARM design have encouraged distributors to develop index-like formulas with C factors or revenue growth factors that effectively replace capital revenue escalation based on indexing with escalation that is primarily based on cost forecasts. Capital revenue requirement growth has in most plans been nominally slowed by a productivity factor and stretch factor, but the productivity factor has been zero. Custom IR has thus typically entailed “phantom” productivity growth offsets and no role for inflation indexing in limiting capital revenue escalation.
- As multi-year forecasts of capital cost came to play a central role in CIR ARM design, PEG’s view is that OEB panels became increasingly disenchanted with this approach and outspoken in their requests for alternative ARM design methods. In addition to noting high regulatory cost, the OEB has on several occasions made statements implying that a forecasted ARM yields weaker performance incentives than an indexed ARM.
- Notwithstanding the OEB’s expressed misgivings about forecasting, capex forecasts are still a central feature of utility CIR proposals and forecasts of OM&A costs are increasingly commonplace in these proposals as well.

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<sup>40</sup> Ontario Energy Board, “January 8, 2026 Letter Re: An Integrated Approach to Utility Remuneration – Next Generation Rate Framework (EB-2026-0002),” Appendix A, p. 4.

- In most of the CIR plans approved to date, an  $I - X$  formula that may also include a growth factor has effectively escalated the OM&A revenue requirement. Here  $I$  is the OEB's approved inflation factor for power distributors. The reasonableness of this index formula in an application to OM&A specifically has often been assumed rather than demonstrated even though distributors have been quick to question its reasonableness in an application to capital specifically.
- A logical next step in the design of ARMs for CIR is to consider what rate and revenue cap indexes are appropriate for OM&A and capital revenue specifically. PEG has discussed this option in prior testimony on behalf of OEB Staff.<sup>41</sup>
- The OEB has only provided general guidelines for CIR and has been open to diverse and evolving plan designs in utility-specific rate-setting proceedings. The approved innovations have included revenue caps, the addition of growth terms to revenue cap indexes, and incremental capital stretch factors. Some plans have included clawbacks of capital cost underspends while others have not.
- CIR and the Ontario approach to IR generally were developed before some IR mechanisms used today were well-established. These mechanisms include historical own-cost trending approaches to ARM design that we discuss in a later section.

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<sup>41</sup> See, for example, Exhibit M in EB-2019-0261 (Hydro Ottawa).

### 3. OPG's Rate Regulation

Section 78.1 of the Ontario Energy Board Act authorizes the OEB to set payment amounts (e.g., a price expressed as dollars per MWh of generation) to be paid by the Independent Electric System Operator ("IESO") for power produced from prescribed generation assets of OPG.<sup>42</sup> Six large hydroelectric generating stations were prescribed for Board regulation in 2005.<sup>43</sup> Most of these are located in the Niagara region [e.g., Sir Adam Beck ("SAB") 1 and 2]. Another 48 hydroelectric stations were prescribed for Board regulation effective in 2014.<sup>44</sup> In total, more than 6,500 MW of hydroelectric generating capacity was subject to OEB rate regulation in 2025.<sup>45</sup>

O. Reg. 53/05 provides the OEB with some discretion as to "the form, methodology, assumptions and calculations used in making an order that determines payment amounts" for OPG's prescribed facilities. O. Reg. 53/05 and OEB decisions have authorized variance and deferral accounts for regulated hydroelectric ratemaking that include the following:

- Pension and OPEB Cost Variance Account
- Pension and OPEB Cash Versus Accrual Differential Deferral Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account-Hydroelectric
- Income and Other Taxes Variance Account
- Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Surplus Baseload Generation variance account compensates OPG when the company is unable to store water in a surplus baseload generation ("SBG") situation. The Hydroelectric Incentive Mechanism ("HIM") was established in EB-2007-0905. It encourages OPG to increase

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<sup>42</sup> This has been calculated as OPG's revenue requirement divided by its forecasted generation volume.

<sup>43</sup> Ontario Regulation 53/05 filed February 2005.

<sup>44</sup> Ontario Regulation 312/13 filed November 2013.

<sup>45</sup> A1-Staff-285, Attachment 2.

production above monthly averages in hours when the market-clearing price exceeds the regulated payment amount. The HIM functions as a revenue sharing mechanism, allowing OPG to keep half of any increase in revenues from providing extra generation when power prices are above the regulated payment amount net of production shortfalls multiplied by the regulated payment amount for hours in which its production is less than forecast.

O. Reg 53/05 also provides that the OEB shall ensure that OPG recovers capital and non-capital costs and firm financial commitments that it incurs to increase the output of, refurbish, or add operating capacity to prescribed hydroelectric assets that are prudently incurred. A Capacity Refurbishment and Variance Account ("CRVA") was established in EB-2007-0905 and has been approved in all subsequent OPG rate applications. This account records variances between the revenue requirement impact of in-service additions to increase the output of, refurbish, or add operating capacity to prescribed generation facilities and the associated forecasts underpinning revenue requirements approved by the OEB.

The OEB has considered alternative ways to regulate OPG in EB-2006-0064.<sup>46</sup> It determined that, while IR might be preferable for the Company in the long run, it should be preceded by a period of cost of service regulation. The OEB established a flat rate per MWh sold from prescribed hydroelectric facilities. These rates were set in a sequence of cost of service proceedings (EB-2007-0905, EB-2010-0008, and EB-2013-0321), each of which involved two forward test years. OPG had one stay out year between each of these filings.

In 2011 the Board retained Power Advisory LLC to prepare a report on IR options for OPG's prescribed generation. Power Advisory recommended an IRM for OPG's hydroelectric operations with the following provisions:

- payment amounts escalated by a price cap index featuring a "modest" X factor and a Z factor;
- earnings sharing and off ramp mechanisms;
- retention of the HIM; and

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<sup>46</sup>OEB, A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation, Inc., November 2006.

- continuation of after-the-fact reviews of OPG's performance during SBG conditions.<sup>47</sup>

The OEB endorsed these findings, particularly given that the Niagara Tunnel project had been completed, "the capital investment schedule for the hydroelectric assets will now more closely resemble the 'steady state' that is desirable for IR-based payment setting" and that "an IR mechanism for OPG's prescribed hydroelectric assets is appropriate". The OEB outlined a process by which IR would be applied to OPG's hydroelectric assets.<sup>48</sup>

In 2015, the OEB issued a letter stating that "it is appropriate to incorporate IR into the rate-setting mechanism for OPG... A long-term, properly designed IR mechanism has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs."<sup>49</sup> Using the parlance of its regulatory system for power distributors, the Board recommended a price cap IR framework for OPG's hydroelectric assets and a custom IR framework for its nuclear assets.

In 2017 the OEB approved a price cap plan to set OPG's hydroelectric payment amounts for the 2017-2021 period.<sup>50</sup> Rates were not rebased in this proceeding. The approved plan escalated payment amounts by Inflation - X, where Inflation consisted of a weighted average of the growth in the GDPIPI FDD for Canada and the Average Weekly Earnings for the Ontario Industrial Aggregate. The weights for each measure were based on an industry average. The X factor was the sum of a 0% productivity trend and a stretch factor of 0.3%.

Two avenues for supplemental capital funding were made available to OPG as part of the plan. One was the continuation of the CRVA during the plan term. No explicit adjustments were made to the terms of the plan to account for this, except to apply the index to the threshold amount for CRVA-

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<sup>47</sup> Power Advisory LLC, Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets, April 2012, pp. 85-86.

<sup>48</sup> Ontario Energy Board (2013), "Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets EB-2012-0340", p. 7.

<sup>49</sup> OEB, "Re: Incentive Rate-Setting for Ontario Power Generation's Prescribed Generation Assets," Letter to all participants in EB-2012-0340, all participants in EB-2013-0321, and all other interested parties, February 17, 2015, p. 1.

<sup>50</sup> EB-2016-0152.

qualifying capital projects. An estimated 35% of OPG's capital spending was CRVA-eligible.<sup>51</sup> OPG also had the option to request funding through an incremental capital module. However, the Company did not request funding through the incremental capital module during the price cap IR plan.

The Company has been subject to a payment amounts freeze for its regulated hydro operations since 2022. During this freeze, OPG has had the option to book amounts to the CRVA for disposition in a future proceeding. OPG has booked amounts to the CRVA for each year of the 2022-2025 period.<sup>52</sup> The CRVA had a \$219 million balance as of December 2025.<sup>53</sup> OPG reports that it overearned on its prescribed hydro operations in every year of the 2022-2024 period.

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<sup>51</sup> Ontario Energy Board (2017), "Decision and Order EB-2016-0152 Ontario Power Generation Inc Application for payment amounts for the period from January 1, 2017 to December 31, 2021", p. 130.

<sup>52</sup> EB-2023-0536, Exhibit H1, Tab 1, Schedule 1 and H1-Staff-260, Attachment 2, Table 1. OPG is not requesting to clear the CRVA in this proceeding.

<sup>53</sup> H1-Staff-260, Attachment 1, Table 1

## 4. Evaluating OPG's Proposed CIR Framework

### 4.1. Summary of OPG's Evidence

OPG is proposing a Custom IR plan that enables it to “address the substantial incremental capital investments required over the forecast period which would not be funded under the price-cap framework.”<sup>54</sup> Supportive statistical cost research has been provided by London Economics International. Here are some key provisions of the Company's proposal:

- The term of the plan would be the five years from 2027 to 2031.
- Rates for 2027 would result from a cost of service rebasing using a fully-forecasted test year.
- Base rates in the last four years of the plan would be escalated by a “price cap” index with the following growth formula

$$HPA_t = HPA_{t-1} \times [1 + (I - X + C - GRCF)].$$

Here is an explanation for the terms in this formula.

- HPA is the hydroelectric payment amount.
- *I* would be a time-variant inflation factor that is a cost-weighted average of recent historical inflation in Canada's Gross Domestic Product Implicit Price Index - Final Domestic Demand and the Average Weekly Earnings for Ontario – Industrial Aggregate. The proposed weights for these two inflation subindexes would reflect generation industry costs and be based on LEI calculations.
- *X*, the X factor, would be the sum of a fixed 0% Productivity Factor supported by LEI's productivity trend evidence and a fixed Stretch Factor of 0.15% that is supported by LEI's econometric benchmarking evidence.
- *C* would be a predetermined but time-variant Custom Capital Factor that is portrayed as providing the supplemental revenue needed to fund the Company's capital projects.
- GRCF is a predetermined GRC Factor that would adjust rate escalation so that the revenue requirement for gross revenue charges and other water agreement costs is constant over the IR term.

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<sup>54</sup> Exhibit A1, Tab 3, Schedule 1, p. 17.

- The C factor and the GRCF together effectively produce an attrition relief mechanism for the last four years of the plan that has a hybrid design.
  - Allowed capital revenue would be escalated for the forecasted growth in OPG's capital-related revenue requirement ("CRRR") over the 2028-2031 period less the 0.15% X factor. The CRRR would be based on traditional capital cost accounting.
  - A GRC Factor would offset increases in Gross Revenue Charges that arise from the application of the index to those costs, effectively freezing Gross Revenue Charges for the five-year term.
  - The revenue requirement for other OM&A expenses would be escalated using the  $I - X$  formula.
  - The *net* OM&A revenue requirement would be established by subtracting other operating revenue.
- An Earnings Sharing Mechanism ("ESM") would asymmetrically share any cumulative earnings for the combined regulated hydroelectric and nuclear operations over the five years of the plan that exceed the established return on equity target by 100 basis points 50/50 between the Company and its customers.
- A Hydroelectric Water Conditions Variance Account would address the financial impact (e.g., revenues and changes in Gross Revenue Charge costs) of any variance between the actual generation volume and the forecasted volume arising from changes in water conditions at OPG's large hydroelectric facilities.
- A Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") would address the financial impact of foregone production due to surplus baseload generation conditions at OPG's large hydroelectric facilities.
- A Capital-Refurbishment Variance Account ("CRVA") would address variances, positive and negative, between actual and forecasted cost of increasing the output of, refurbishing, or adding operating capacity to a prescribed generation facility. CRVA-eligible capex is included in the calculation of the C factor.
- A Gross Hydroelectric Capital Variance Account ("GHCVA") would asymmetrically return to customers any cumulative positive difference between the proposed capital revenue requirement and actual capital cost during the 2028-2031 period.
- Costs and revenues eligible for deferral and/or variance account treatments that are separate from the price cap index would include those for pensions and other post-employment benefits; changes in Gross Revenue Charges due to deductions or changes in legislation or regulation; the impact of transitioning to international financial reporting standards from US GAAP; the impact



of clean energy investment tax credits (refunds only if not addressed by an existing deferral and variance account); the impact of changes in laws or regulations (if not already addressed in other deferral and/or variance accounts); and changes in income and other taxes due to changes in tax rates, tax rules, or assessments.

- Difficult to foresee events exceeding a \$20 million materiality threshold would be addressed through an accounting order process.
- Standard off-ramp provisions would apply.

## 4.2. OPG's Rationale for CIR

OPG discusses the drivers underlying the need for CIR in its filing. One major theme is the need is to “address the significant capital investment that could not be funded in a timely manner through a typical price cap framework.”<sup>55</sup> OPG proposes rapid growth in its capital cost during the new plan due to high capital spending. Plant additions are forecasted to be about 220% higher in nominal terms than the 2022-2026 average and about 190% higher in real terms.<sup>56</sup>

The primary driver of increased capital investment is associated with asset refurbishment. OPG claims that the average age of its regulated hydroelectric stations is about 90 years, with some stations in excess of 125 years old.<sup>57</sup> As a result, many of its stations require refurbishment, and the Company has proposed 53 refurbishment projects that are expected to come into service during the CIR plan term.<sup>58</sup> Several additional stations are forecasted to be redeveloped. OPG expects that its refurbishment plans will sustain “approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW.”<sup>59</sup> The Company indicates that these refurbishments are in alignment with Ontario’s Integrated Energy Plan, *Energy for Generations*.

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<sup>55</sup> Exhibit A1, Tab 3, Schedule 2, p. 3.

<sup>56</sup> Calculations based on Table 2 presented in Section 6.3 of this report.

<sup>57</sup> Exhibit A1, Tab 3, Schedule 1, p. 12 and Exhibit A1, Tab 4, Schedule 2, pp. 2-3.

<sup>58</sup> Exhibit F1, Tab 1, Schedule 1, p. 5.

<sup>59</sup> Exhibit F1, Tab 1, Schedule 1, p. 5.

OPG's forecast of capital expenditures and plant in service is unusual relative to other Ontario utilities in that it includes projects for which the scoping work is not complete and final approvals from OPG's Board of Directors have not yet been made. OPG explains that it is "in the process of refining their scope and completing their conceptual, preliminary, and detailed designs" which may lead to "changes in key project assumptions around cost and schedule that will be refined as the project progresses."<sup>60</sup> During the CIR term, about 60% of OPG's portfolio capex (e.g., projects that are sustaining investments supporting the continued operation and reliability of OPG's assets and are not part of extraordinary investment programs), 43% of its refurbishment capex, and at least 38% of its overall capex is for projects that are not fully scoped.<sup>61</sup>

The need for CIR is diminished for capex that can be addressed by the CRVA. However, in response to A1-Staff-289 part b, OPG argues that the funding provided by the CRVA is not timely.

The proposed CRVA methodology requires the balance to be evaluated on a cumulative basis over the IR period. This means that the balance recorded in the account cannot be evaluated until an application filed after the conclusion of the period, with recovery beginning subsequent to such an application. For example, an application to dispose of deferral and variance account balances could be filed in 2033 requesting disposition to begin in 2034. This timeline demonstrates that the recovery of costs incurred using the CRVA is delayed as compared to the use of the C-factor.

OPG did not provide a forecast of OM&A expenses for the entirety of the Custom IR plan term. Application of the index for OM&A expenses "preserves the efficiency incentives inherent in a price-cap model for 'steady state' operations," suggesting that OM&A is not a driver of OPG's need for CIR.

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<sup>60</sup> Exhibit D1, Tab 1, Schedule 2, p. 6.

<sup>61</sup> Exhibit D1, Tab 1, Schedule 1, Table 2.

## 5. PEG Critique: Price Cap Index Formula

PEG notes the following concerns about OPG's proposed custom price cap index.

### 5.1. Stretch Factor

In Appendix Section 5, PEG discusses many concerns about the benchmarking studies LEI undertook, of which the following are the salient:

- LEI relied on a data source for its benchmarking research that it believes cannot be released to parties in this proceeding even under confidential seal, as discussed in the response to A1-Staff-333. This issue renders it nearly impossible for parties to verify that the calculations underlying the study were completed accurately and to rely on it for ratemaking purposes.
- LEI's study, unlike most other benchmarking studies undertaken to support Custom IR proposals, only looked at historical cost performance. Parties are thus unable to glean insights as to how OPG's cost performance is expected to change after 2023, including for the entire Custom IR plan term.
- LEI's benchmarking methods were different than those typically used in benchmarking studies for IR proceedings and we have reservations about many of their methods.

Based on an alternative benchmarking study that addressed these and other concerns, PEG recommends a stretch factor of **0.30%**.

PEG also benchmarked the O&M and capital costs of OPG. This research revealed that a remarkable decline is expected in the Company's O&M cost performance in 2027, the first year of the plan. This raises concern about strategic cost deferrals that PEG discussed in the recent Spending Pattern Analysis report for OEB staff. OPG's OM&A revenue has been limited by a rate freeze for several years but nonetheless has not reported an earnings deficiency in these years.

### 5.2. Productivity Factor

PEG's concerns about LEI's method for measuring the TFP trend of hydro generators are discussed at some length in Section 6 of the Empirical Appendix. Our own study nonetheless finds that the OM&A, capital, and total factor productivity trends of the industry are materially negative. We

believe that this is a good time to restate reasons why the use of negative productivity factors in ratemaking can make sense when there is strong evidence of declining industry productivity. Productivity is not a pure measure of cost efficiency and can reflect mounting external cost pressures such as a general increase in system age. The OEB already reasonably provides automatic rate relief for external pressures resulting from input price inflation and, in some plans, customer growth. Most hydroelectric generators in the United States are not, like the power transmitters considered in a Hydro One proceeding a few years ago, regulated by incentive-weakening formula rates.

A negative productivity factor can reduce the supplemental revenue that utilities need from CIR and their complaints about implicit stretch factors. These complaints are sometimes legitimate as they pertain to OM&A revenue (which is escalated by I-X) and reduce the reasonableness of beefing up stretch factors on other grounds. PEG explains in Section 2.1 of the Appendix that a negative productivity factor would not be used to accelerate revenue requirement growth that is based on a cost forecast. In CIR it has the effect of reducing the C or revenue growth factor. Based on this reasoning we recommend a **-0.47%** Productivity Factor for OPG provided that the panel also adopts our capital revenue recommendations as discussed in the next section.

### 5.3. Price Cap Index Design

PEG agrees that a price cap rather than a revenue cap is warranted for OPG's prescribed hydro generation. This will provide stronger incentives for the Company to maintain or increase its hydro generation volume. However, for reasons explained at length in Appendix Section 6, it makes sense to measure the industry productivity trend using generation *capacity* rather than *volume* as the output metric. Since capacity is more of a *cost* than a *revenue* driver, this method for calculating TFP is more appropriate for a *revenue* cap index than for a *price* cap index. To create a price cap index, it is necessary in principle to adjust the index formula for any material difference between the capacity and the volume trends of OPG. This conversion uses an output differential that is discussed in Appendix Section 2.1. However, we show in the Appendix that this "output differential" is essentially zero for OPG.

## 6. PEG Critique: Reliance on Cost Forecasts

### 6.1. Overview

OPG's proposal also raises other IR plan design issues. Most notable is its proposal to effectively base the entirety of its capital revenue escalation on a capital cost forecast (less a small stretch factor) and to claw back any capital cost underspends to customers. Those plan design features raise many concerns that PEG has discussed in past CIR proceedings.<sup>62</sup>

### 6.2. Forecasting Pros and Cons

We begin by reviewing pros and cons of using forecasting in revenue escalation.

#### Forecasting Pro

One important advantage of forecasting is its ability to tailor ARMs to various cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capital cost surge such as OPG proposes. Unless underspends are returned to customers, the incentive to contain cost is still material. Another advantage is that capital cost forecasts are made using familiar capital cost accounting.

#### Forecasting Con

##### Uncertainty and Information Asymmetry

The biggest challenge with forecasted ARMs may be the difficulty of establishing a just and reasonable multi-year cost forecast. The efficient future cost of service is usually uncertain, and uncertainty increases with the length of the MRP term. For example, capital cost forecasts can be wrong about inflation.

The inflation uncertainty problem can be mitigated by making forecasts of capital costs, capital expenditures, or gross plant additions contingent on an inflation assumption that is later trued up to actuals.

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<sup>62</sup> See, for example, PEG's plan design discussion in the recent THESL proceeding (EB-2023-0195).

The OEB has approved explicit true ups of forecasted inflation to actuals for the C factor in the current CIR plan of Hydro One networks and the RGF factor in the current CIR plan of Toronto Hydro.<sup>63</sup> Advanced and incremental capital modules also feature an implicit true up of inflation assumptions to actuals. The forecasted revenue requirements of British power distributors for the MRP plan term are approved in real terms that are subsequently adjusted to account for inflation. Many capital cost trackers in the US implicitly true up inflation assumptions to actuals as part of a prudence review.

We are also concerned that utilities are incentivized to overstate required cost growth. Padding a cost forecast reduces the pressure on the utility to achieve cost savings and can legitimize more capex than it really requires. The utility may also be able to profit in the short term from spending less than it forecasts. Exaggeration of required revenue may reduce the company's credibility in future proceedings. However, the utility can always claim that it "discovered" ways to economize. This problem can also be finessed by spending close to the padded forecast, even if it isn't efficient. Concerns about information asymmetries and an uncertain future are often addressed by shortening the plan term and truing up forecasted costs to actual cost.

### Cost Containment Incentives

Another concern is the utility's incentive to contain costs when revenue escalation is based on forecasts. A utility is much more likely to undertake a capex surge when it is expressly approved in advance. In the United States, for example, submissions to regulators of distribution system plans have in many cases led to ambitious multiyear capex proposals. Utilities are incentivized to "bunch" their costs in ways that support their proposal to base ARMs on cost forecasts. If, for example, a utility could somehow manage to time its expenditures so that indexing was sufficiently compensatory, it would obtain less revenue. Incentives are further weakened by a clawback of underspends. If forecasting applies only to capital revenue, imbalanced incentives for capital and OM&A cost containment are a real concern. Incentives to contain a forecasted cost in a multiyear rate plan may nevertheless be stronger than under frequent rate cases or two-way variance accounts that fund overspends as well as returning underspends. OPG proposes such a clawback and additionally a two-way variance account for

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<sup>63</sup> EB-2021-0110 and EB-2023-0195.

refurbishment capex. PEG estimates that at least 45% of OPG's plant additions during the out years of the CIR plan (e.g., 2028-2031) are eligible for the CRVA.

### Regulatory Cost

Given OPG's weak incentive to contain CRVA-related costs, and the Company's incentive to exaggerate cost requirements and bunch costs, stakeholders and the OEB must be especially vigilant about the Company's cost proposal. This raises regulatory cost. The need for the OEB to approve multi-year revenue requirements greatly complicates CIR proceedings and is one of the reasons why the OEB now requires and must review complicated distribution system plans - a major expansion of its workload and that of stakeholders.

Despite the extra regulatory cost, OEB staff and intervenors inevitably struggle to effectively challenge the utility's cost proposal. Some regulatory communities lack the expertise to appraise multi-year cost forecasts. However, many commissions routinely use forward test years in rate cases and some of these use multiple test years. Some commissions also periodically review multi-year business plans of utilities or pay special attention to utility proposals for major plant additions (e.g., in proceedings to approve certificates of public convenience and necessity). Ontario's regulatory community does both.

In summary, a forecasted ARM weakens utility cost containment incentives relative to an indexed ARM and can further jeopardize customer benefits from IR due to the problem of information asymmetry. The utility is incentivized to include a comfortable cushion in its cost forecast. While the proposed clawback mitigates some of the concern about information asymmetries, this further weakens capex containment incentives. The approach to CIR that OPG proposes thus undermines the *main potential benefits* of multi-year rate plans -- stronger performance incentives and streamlined ratemaking.

Here are some additional concerns about undue reliance on forecasting that PEG has enunciated in prior CIR proceedings.

- While customers ultimately must fully compensate OPG for the bulk of its expected revenue shortfalls when cost growth is *rapid* for reasons beyond its control, the Company would be under no obligation in the future to return any surplus revenue if it chose to operate under

indexing and its cost growth was unusually *slow* for reasons beyond its control. Slow cost growth could occur in the future for reasons other than good cost management. For example, depreciation of surge capex which has provided the rationale for Custom IR will tend to slow future capital cost growth. Over multiple plans, the revenue escalation between rate cases may therefore not guarantee customers the full benefit of the industry's productivity trend, even if it is achievable.

- A related problem is that most of the cost addressed by the C and Z factors would be similar in kind to that incurred by the utilities in past and future productivity studies that are used to determine productivity factors. The Company can then be compensated twice for the same cost: once via the C factor and then again by low X factors in past, present, and future IRMs.
- If forecasting applies only to capital, any indexed ARM designed to fund total cost may be overly generous to the costs to which it really applies.
- This overcompensation issue when an indexed ARM is combined with supplemental capital revenue has been debated in several IR proceedings and no consensus has been established regarding its remedy. Some regulators have eschewed X factor adjustments that might address overcompensation and based X factors on industry productivity trends. However, the Hawaii Public Utilities Commission ruled in a 2020 IR decision that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that some of their major plant additions could be eligible for cost tracking.<sup>64</sup>

### **6.3. Alternative Approaches to Capital Revenue Escalation**

The preceding discussion has implications for the design of ARMs for OPG and other Ontario utilities. Let's start by assuming that the utility does need some form of CIR because its revenue requirement is rising quite a bit more rapidly than the escalation that indexing by itself affords. OPG is

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<sup>64</sup> Hawaii Public Utilities Commission (2020), Decision and Order No. 37507, Docket No. 2018-0088.

forecasting rapid cost growth in the next five years. A comprehensive indexed ARM will therefore not be practical for OPG in its next rate plan.

However, there are notable alternatives to the established CIR approach to capital revenue escalation that OPG proposes. Many of these have been discussed by PEG in prior reports for OEB Staff.

### **Reduce the Share of Any Gap Between Indexed Revenue Growth and Forecasted Capital Cost That is Eligible for Supplemental Revenue**

This option is discussed in Appendix Section 2.1. Rationales for narrowing the gap include the need for a materiality condition and a strengthening of capex containment incentives. There is a dead zone in the incremental and advanced capital modules that are available to distributors under the 4<sup>th</sup> GIRM. To not have at least as large a dead zone in CIR encourages utilities to choose CIR.

Two approaches to narrowing a given gap between indexed revenue growth and forecasted cost growth are discussed in the Appendix: a supplemental capital stretch factor and a mechanistic sharing of differences. The OEB has approved supplemental capital stretch factors for several CIR plans as shown in Table 1.

Table 1

### **Precedents for Supplemental Stretch Factors on Capital**

| <b>Company</b>     | <b>Service</b>     | <b>Case Number</b> | <b>Approved Supplemental Stretch Factor on Capital</b> |
|--------------------|--------------------|--------------------|--|
| Hydro One Networks | Power distribution | EB-2017-0049       | 0.15%  |
| Toronto Hydro      | Power distribution | EB-2018-0165       | 0.30%  |
| Hydro One Networks | Power transmission | EB-2019-0082       | 0.15%  |
| Hydro Ottawa       | Power distribution | EB-2019-0261       | 0.15%  |
| Hydro One Networks | Power distribution | EB-2021-0110       | 0.20%  |
| Hydro One Networks | Power transmission | EB-2021-0110       | 0.20%  |
| Toronto Hydro      | Power distribution | EB-2023-0195       | 0.30%  |
| Hydro Ottawa       | Power distribution | EB-2024-0115       | 0.225%   |

## Increase the I-X Growth Applicable to Capital

If CIR is premised on the difference between the growth of indexed capital revenue and forecasted costs, any legitimate means of making indexed capital revenue grow more rapidly would reduce the need of utilities to request CIR and the supplemental revenue requested. Here are some possibilities.

- The inflation measure applicable to capital revenue could be replaced, if it is found to materially understate capital price growth, with an alternative measure that does a better job. This is a complicated empirical issue that has never been properly addressed in the OEB's rebasing/IR proceedings and is perhaps best addressed in a generic IR proceeding. An alternative to a capital-specific inflation index is adding an input price differential ("IPD") term to the index formula. IPDs applicable to *OM&A* revenue have been proposed by Alectra Utilities and Elexicon in their current rebasing/CIR proceedings.
- The partial factor productivity ("PFP") trend of capital in the relevant industry can be used to set the productivity factor for capital if that is materially slower than the TFP trend. This approach has been advocated by PEG as a witness for Staff in the Elexicon and Alectra Utilities proceedings.
- A negative productivity factor can be approved if there is strong evidence that the productivity trend of the industry is negative and that trend is applicable to the subject utility. This approach was discussed in Appendix Section 2.1. We explain how a negative productivity factor can be reasonably applied in the context of CIR. When a negative industry productivity trend is ignored, utilities are more likely to choose the CIR option. Moreover, they can in some cases legitimately complain that there is an "implicit" stretch factor in the I-X formula. When this is true, it reduces the reasonableness of increasing the stretch factors in their formulas on other grounds.

## Reduce the Escalation of OM&A Revenue

We discussed above how the application to OM&A revenue of an indexed ARM designed to escalate the total cost of power distributors may result in overcompensation. Making the OM&A

revenue escalator more OM&A specific in this case makes CIR less appealing at the same time that it benefits customers.

## **Historical Own-Cost Trending**

This approach may or may not be considered in the OEB's next generation rate framework initiative, so this proceeding is a good place to continue discussions on its merits. The basic idea is that a utility's budget for some kinds of capex or gross plant additions in one plan is based on an average of the utility's capex in the last plan. There is no true up to actuals. Here are some real-world examples of historical own-cost trending.

### California "Old School" Approach

California's commission has required energy utilities to operate under MRPs for decades but does not like to base ARMs on multiyear cost forecasts. Hybrid ARMs have been used in numerous MRPs wherein much of the post-test year OM&A revenue requirement has been indexed. That for capital is based on a calculation that uses traditional cost of service capital cost accounting but includes the simplifying assumption that gross plant additions reflect either the company's approved additions for the first year of the plan or an average of the company's recent historical additions. The plant additions in these calculations have sometimes been escalated for price inflation.

### Alberta's K-bar Approach

The Alberta Utilities Commission ("AUC") has approved three rounds of generic MRPs for gas and electric power distributors that it calls PBR plans. A "K-bar" approach to ARM design has been featured in the PBR2 and PBR3 plans that is a variant on the California theme. The commission was disappointed with some results of the PBR1 plan, where extensive use of capital cost variance accounts weakened the capex containment incentives of distributors and raised regulatory cost. The K-bar approach was originally suggested in the hearing to approve PBR1 by AUC commissioner Moin Yahya, a University of Alberta law school professor who earned a PhD in economics at the University of

Toronto.<sup>65</sup> K-bar is a mathematical expression for a value of a K factor term in rate or revenue cap index that is in some sense fixed.

The recently approved PBR3 plan for Alberta energy distributors provides an example of the use of K-bar in the context of an approaching energy transition. PBR3 features a hybrid ARM where rates for energy distributors are escalated by an index and supplemental funding is available for certain kinds of capex. “Type 1” capex is eligible for forecasting with subsequent variance account treatment. In order to qualify as Type 1 capex, a project must have a material effect on the distributor’s finances, be required by a third party or directly caused by applicable law related to net-zero objectives, and be extraordinary and not previously included in the distribution utility’s rate base. Capex that is not deemed to be of Type 1 is “Type 2” capex and is addressed by the K-bar mechanism. All existing capex programs are treated as Type 2 capex by default.

For Type 2 capex, this mechanism effectively replaces capital revenue based on indexing by capital revenue based on historical own-cost trending. This is a multistep process undertaken for each year of the plan term which begins by identifying the capital revenue generated by going in rates escalated by the indexing mechanism. The next step is to estimate a notional capital revenue requirement needed to fund the Type 2 capex that would be undertaken in a given year. For this, the AUC relies on the five-year average capital additions from the prior plan term (e.g., 2018-2022), which is then escalated by the approved I – X formula and 85% of customer growth. These amounts are then converted into a capital revenue requirement using assumptions about retirements and a mid-year rate base. The K-bar term in the ARM formula then ensures that an amount is added to rates that is the difference between the inflation-adjusted notional capital revenue requirement and the inflation-adjusted capital revenue requirement embedded in going in rates. To the extent that the distributor spends less on capital than expected by K-bar, the distributor retains the amount. In other words, there is no clawback of capital underspends.

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<sup>65</sup> AUC proceeding 566, Transcript Vol. 10, April 27, 2012, pp. 1918-1922.

### Massachusetts K-bar Approach

The ARM design for power distributor services of Eversource Energy in Massachusetts is a variant on the Alberta theme. The capital revenue requirement in each out year of the plan is calculated using a *rolling average* of the company's recent plant additions.<sup>66</sup> To reduce the chance that the company may have excessive plant additions, a cap on the amount of annual plant additions supported by K-bar has been established. This annual cap is 10% above the level of annual plant additions that the company forecasted in the proceeding. The prudence of any plant additions subject to K-bar treatment may be investigated at any time and the company has been placed on notice that the regulator may review its capital spending if it determines that the company over-estimated its plant additions forecast and was underinvesting in capital. In return for the supplemental capital revenue that K-bar provides, Eversource agreed to a zero X factor even though the utility had made a case for a negative X factor due to IPD concerns.<sup>67</sup>

### Historical Own-Cost Trending Appraisal

Historical own-cost trending can reduce the cost of ARM design and strengthen capex containment incentives relative to a forecast with clawbacks when a utility is expected to need sufficiently high capex for a number of years that an indexed ARM is non-compensatory for capital revenue. However, the incentive impact of the approach weakens if utilities suspect that capital revenue growth in future plans reflects their gross plant additions in the latest plan. The productivity growth of California power distributors has been unremarkable, although this has reflected in part special circumstances such as heightening wildfire challenges.

A paper on a study by PEG that was published in *The Electricity Journal* in 2023 revealed that in PBR1, with its capital cost variance accounts, the capital productivity growth of participating Alberta

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<sup>66</sup> Massachusetts Department of Public Utilities, D.P.U. 22-22, 2022.

<sup>67</sup> Recall that this is more of a concession in the United States than in Canada since the GDPPI that is widely used in indexed ARMs in the States tends to materially understate utility input price inflation and this often results in an X factor adjustment that makes it negative.

energy distributors was just as sluggish as in the prior period of frequent rebasings.<sup>68</sup> In PBR2, however, replacement of variance account treatment of supplemental capital revenue with a K-bar caused material acceleration in the capital productivity growth of Alberta energy distributors.

### Historical Own-Cost Trending for OPG

We broached the topic of historical own-cost trending in our report for OEB Staff in the Toronto Hydro CIR proceeding. In this proceeding we have taken further steps to explore the option.

- OPG forecasts plant additions in the next five years that are well in excess of its recent historical norms. To the extent that the OEB believes that the rapid proposed cost growth is required and is not merely a manifestation of the asymmetric information problem and a utility's incentive to increase capital spending under a forecasted ARM, the situation can be finessed using forecasting and/or variance accounts to address some rapidly growing capital costs and then use historical own-cost trending for the residual capital revenue requirement. The OEB may prefer traditional prudence oversight anyways of some rapidly growing costs (e.g., refurbishment capex) that are accorded forecasting and/or variance account treatment. Own-cost trending would materially reduce the role of forecasting in the determination of the Company's revenue requirement.
- We have shown that historical own-cost trending is a well-established alternative to forecasting for capital revenue. OPG could be assigned a gross plant additions budget for some asset categories that are similar (in the dollars of the next plan) to their average plant additions during the expiring plan. Either the old school California approach or the Alberta K-bar approach could be used. Both of these approaches should yield considerably more revenue than indexing of capital revenue would.

The approach to own-cost trending explored here is closer to California's approach than to the Alberta approach and is designed to dovetail with the ARM design approach that OPG has

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<sup>68</sup> Lowry, Mark N., Hovde, D., Kavan, R., and Makos, M., "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta," *The Electricity Journal*, 36 (2023) 107288.  
<https://doi.org/10.1016/j.tej.2023.107288>

proposed. Essentially, the Company would have a CPCI formula with a C factor, but historical own-cost trending would be used instead of cost forecasting to establish gross plant addition budgets for some asset categories. There would be no explicit K-bar term in the formula. Capital revenue growth would still be reduced by the stretch factor.

- Due to information asymmetry, it is difficult for OEB Staff or intervenors to undertake all of the complex calculations needed to fully demonstrate the rate or revenue impact of historical own-cost trending for OPG. The Company has specialized accounting knowledge that other parties to the proceeding lack. For this reason, we asked OPG to demonstrate the revenue requirement impact of implementing a hypothetical own-cost trending example. In its response to A1-Staff-292, the Company refused to consider a scenario involving this approach. Nevertheless, we have endeavored to undertake the first steps.

We flesh out here a straw man proposal in which OPG's capital revenue requirement depends on a mix of cost forecasts, some with variance account adjustments, and historical own-cost trending. In its EB-2025-0297 direct evidence, the Company disaggregated its proposed and recent historical plant additions in ways that support this new hybrid approach.

Table 2 below illustrates how some kinds of plant additions could be subject to forecasting and/or variance account treatment, while other kinds could be accorded historical own-cost trending. The sorting in this table is intended to stimulate thinking. We generally avoided own-cost trending for asset categories where plant growth was either expected to accelerate markedly or entirely eligible for CRVA treatment. Capital categories nominated for own-cost trending are highlighted in yellow in the table. Plant additions for these categories from 2022 to 2026 was escalated to 2027 dollar and output levels using the Escalation Factors outlined in Table 3a. The average plant additions for each project (or sub-project) at 2027 levels is then calculated. The escalation factors take account of both inflation and growth in operating scale. For each of the "out" years of the proposed plan (2028-2031), PEG then escalates the plant additions averages from 2027 levels to the applicable year using forecasted Escalation Factors.

The Escalation Factors are a function of the OEB's approved I-Factor based on OPG's proposed inflation factor weights and a forecast of OPG's capacity growth. Table 3b provides additional detail on



Table 3a  
**Calculating the Escalation Factors**

| Line No. | Actuals                                   |         |         |         |         |         |         | Forecasts |         |         |         |         |         |
|----------|---|---------|---------|---------|---------|---------|---------|-----------|---------|---------|---------|---------|---------|
|          | 2020                                      | 2021    | 2022    | 2023    | 2024    | 2025    | 2026    | 2027      | 2028    | 2029    | 2030    | 2031    |         |
| 1        | I Factor*                                 | 3.0%    | 1.6%    | 2.5%    | 10.3%   | 6.3%    | 4.6%    | 6.7%      | 2.5%    | 2.9%    | 1.5%    | 1.8%    | 2.0%    |
| 2        | Inflation Escalation Factor = (1+I)       | 102.99% | 101.61% | 102.49% | 110.32% | 106.34% | 104.61% | 106.70%   | 102.45% | 102.89% | 101.45% | 101.79% | 101.98% |
| 3        | MCR of OPG's Prescribed Generation Assets | 6,430   | 6,430   | 6,440   | 6,556   | 6,556   | 6,566   | 6,572     | 6,584   | 6,605   | 6,628   | 6,633   | 6,633   |
| 4        | OPG's Annual Capacity Growth Rate (CG)    | 0.00%   | 0.00%   | 0.15%   | 1.80%   | 0.00%   | 0.14%   | 0.09%     | 0.19%   | 0.32%   | 0.35%   | 0.07%   | 0.00%   |
| 5        | I+CG Escalation Factor = [1+(I+CG)]       | 103.0%  | 101.6%  | 102.6%  | 112.1%  | 106.3%  | 104.8%  | 106.8%    | 102.6%  | 103.2%  | 101.8%  | 101.9%  | 102.0%  |

**Notes:**

Source of capacity data: A1-Staff-285.

Actual inflation data are available through 2026, however, actual output data are only available through 2025.

The actual inflation data are from the Handy Whitman Index for Total Hydraulic Production Plant in the North Atlantic region. See Table 3b for additional details.

Table 3b  
**Calculating the Inflation Adjustments**

| Line No.                    | Actuals |        |        |        |        |        |        | Forecasts |        |        |        |        |
|-----------------------------|---------|--------|--------|--------|--------|--------|--------|-----------|--------|--------|--------|--------|
|                             | 2020    | 2021   | 2022   | 2023   | 2024   | 2025   | 2026   | 2027      | 2028   | 2029   | 2030   | 2031   |
| 1                           | 7.00%   | 3.50%  | 2.30%  | 3.20%  | 4.90%  | 2.20%  | 2.30%  | 2.30%     | 2.30%  | 2.40%  | 2.50%  | 2.50%  |
| 2                           | 15.30%  | 15.30% | 15.30% | 15.30% | 15.30% | 15.30% | 15.30% | 15.30%    | 15.30% | 15.30% | 15.30% | 15.30% |
| 3                           | 1.70%   | 3.80%  | 5.90%  | 3.70%  | 3.20%  | 2.50%  | 3.00%  | 1.30%     | 1.70%  | 1.90%  | 1.90%  | 2.00%  |
| 4                           | 84.70%  | 84.70% | 84.70% | 84.70% | 84.70% | 84.70% | 84.70% | 84.70%    | 84.70% | 84.70% | 84.70% | 84.70% |
| <b>Inflation Adjustment</b> | 3.0%    | 1.6%   | 2.5%   | 10.3%  | 6.3%   | 4.6%   | 6.7%   | 2.5%      | 2.9%   | 1.5%   | 1.8%   | 2.0%   |

**Notes:**

Inflation forecasts were used to produce inflation factors for the 2027-2031 period. The inflation factor is lagged by 2 years (e.g., the inflation factor for 2026 is based on the inflation that occurred in 2024).

The inflation adjustments for the 2020-2026 period are based on growth in the Handy Whitman Index of Public Utility Construction Costs for Total Hydraulic Production Plant of the North Atlantic Region.

For the 2025-2031 period, PEG purchased forecasts of the Average Weekly Wages and Salaries per Employee for the Ontario industrial composite from Signal 49 Research.

For the 2025-2031 period, PEG obtained Canadian GDP deflator forecasts from Toronto Dominion Economics and used that as a proxy for the Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand. Source: <https://economics.td.com/ca-forecast-tables#t-ca>

the calculation of the inflation adjustments. The growth in the Handy Whitman Index of Public Utility Construction Costs for Total Hydraulic Production Plant in the North Atlantic States is used in these calculations for the years in which actual data are available.<sup>69</sup> Where inflation forecasts are required, we use forecasts of GDPIPI inflation from Toronto Dominion Economics and of AWE<sub>Ontario</sub> inflation that PEG purchased from Signal49 Research (formerly the Conference Board of Canada).

At the bottom of Table 2 we report the total value of plant additions that would hypothetically be accorded forecasting (and in some cases variance account) treatment on the one hand and historical own cost trending treatment on the other. In the right-hand columns it can be seen that the kinds of plant additions we nominate for forecasting and/or variance account treatment are forecasted to be much higher in the new plan than in the expiring plan. Assume that the Company would receive a plant additions budget equal to its forecasts. The inflation-adjusted historical average plant additions that we nominate for own-cost trending is less than the Company's proposed plant additions by about 11%.

Several features of OPG may reduce the effectiveness of historical own-cost trending. For example, PEG's approach to historical own cost trending addresses less than 40% of OPG's proposed plant additions during the 2028-31 period.

- OPG is proposing a rapid run up in plant additions that historical own cost trending cannot easily accommodate. This run up began in 2024, the last year for which we had actual plant additions and will not peak until 2028. We shifted our calculations to include 2025 and 2026 to accommodate some of this, but this presupposes that plant additions in those years are prudent (something we have no position on). It also relies in part on OPG having proposed no expansion project plant additions during the 2028-31 period. These were at least partially successful, though average additions per year of approximately \$497.5 million after adjustment for inflation and output growth are difficult to apply to plant additions for the Custom IR term that average nearly double that amount.
- The incentive power of historical-own cost trending is lower for OPG than for power distributors due to differences in regulatory systems. OPG has access to the CRVA, which compensates OPG

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<sup>69</sup> Forecasts of inflation in these indexes are available from S&P Global.

for variances between actual and forecasted capital costs resulting from CRVA-eligible projects. OPG has little incentive to contain capital costs of these projects. As a result, historical own cost trending will only strengthen OPG's incentives for projects that are ineligible for the CRVA.

- Over the CIR plan term, OPG is claiming that many of its plant additions will be CRVA-eligible. PEG believes that on average at least 45% of OPG's plant additions may be CRVA-eligible during the 2028-31 period.
- CRVA-eligible projects are not clearly itemized in OPG's filing, particularly in the portfolio projects. For example, OPG expects to include several CRVA-eligible projects in its portfolio projects (e.g., project 83194 – Frederick House Lake Dam Rehabilitation, project 84494 – Cheneaux Limerick Island Superstructure Gate Hoist, and 83833 - Silver Falls GS Surge Tank Replacement).
- OPG's plant additions are unusually lumpy relative to power distributors. This appears to lead to some large bulges in plant additions for certain projects in a single year when they are finally completed and able to be fully added to rate base. The Sir Adam Beck 1 GS Canal Rehabilitation project would be a good example of this, since there are only plant additions reported for this project in 2020 and 2029. This means that historical (or historical + bridge) average plant additions are often not going to provide sufficient compensation for forecasted plant additions. By contrast, most capex for power distributors can be placed in service in a considerably shorter period.

## British Remedies

The British regulator, Ofgem, has had extensive experience with forecasted ARMs. The approved revenues of British utilities have often exceeded their actual cost. Due in part to experiences like these, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies in order to develop an independent view of required cost growth. For many years, Ofgem also used an information quality incentive ("IQI") mechanism to encourage utilities to submit better cost forecasts. This mechanism rewarded utilities that presented cost forecasts that were similar to or lower than the forecasts Ofgem developed and penalized utilities that presented cost forecasts that were less

strenuous than Ofgem's. The IQI also determined the rate at which variances between forecasted and actual costs were shared with customers, with utilities that had more efficient cost forecasts receiving a larger share of cost variances.

The IQI has been replaced by a Business Plan Incentive ("BPI"). The BPI in the current power distributor plans consists of several parts, including penalties for distributors that fail to provide sufficient information to appraise their business plans or that provide unreasonably high forecasts in areas where Ofgem is less confident in its forecasting abilities. The BPI also includes rewards for utilities that propose cost forecasts that are below Ofgem's in areas where Ofgem is more confident in its ability to forecast costs.

Ofgem has also marked down distributor cost forecasts to reflect its assumptions about expected productivity gains. These reflect its expectations about the annual productivity gains that companies can achieve during the term of the MRP based on the available evidence on productivity trends. For the current regulatory system for power distributors, called RIIO-ED2, Ofgem expected that distributors achieve 1% efficiency growth per year that is applied to all controllable costs. The efficiency expectation was not tied to a specific productivity study of British power distributors.

## Summing Up

In conclusion, PEG has provided the panel and intervenors with several means of upgrading the ratemaking treatment of capital in the Company's rate plan. A small step and well-precedented step would be to add a custom capital stretch factor to the CPCI formula. Mechanistic sharing of the capital revenue deficit is an alternative worth considering. So is a penalty for a poor capital cost forecast. This could take the form of an addition to the supplemental capital stretch factor in the range between 0 and 0.10%. A bigger step would be to reduce the role of capex forecasting by escalating capex budgets for some asset categories using historical own-cost trending.

## PEG Recommendations

Of all of the options discussed in this section for making CIR work better, PEG recommends combining a **-0.47%** Productivity Factor with a **0.30%** stretch factor and a **0.30%** supplemental capital stretch factor. The negative X factor would accelerate OM&A revenue growth but not capital revenue growth. Consideration should also be paid to a penalty for a poor capital cost forecast.

Should the panel choose not to approve a negative productivity factor, it may reason that OPG may have considered the problem of an implicit stretch factor in proposing a marked increase in its OM&A expenses in 2027 to be followed by I-X escalation.



## 7. PEG Credentials

Pacific Economics Group Research LLC is an economic consulting firm based in Madison, Wisconsin USA. We are the leading North American consultancy on incentive ratemaking and rigorous statistical research on the performance of electric and natural gas utilities. Our personnel have over seventy years of experience in these fields, which have a foundation in economic theory and statistical cost research. Working for an unusual mix of utilities, regulators, government agencies, and consumer and environmental groups, PEG has gained a reputation for objectivity and dedication to sound research methods. Our numerous projects for OEB Staff included research and testimony in the 2016-17 proceeding that approved an IR plan for OPG's hydroelectric business. We have also done several projects over the years in each of the other three populous Canadian provinces. Our practice has also included many IR and benchmarking projects in the United States.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. A former energy economics professor at the Pennsylvania State University, he has spent more than forty years in the field of energy economics since earning a PhD in applied economics from the University of Wisconsin. A frequent expert witness, his specialties include IR, statistical benchmarking, and studies of energy utility input price and productivity trends.

Dr. Lowry speaks frequently on utility ratemaking and has authored dozens of professional publications. He has coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory and prepared several authoritative surveys on IR and other innovations in ratemaking for the Edison Electric Institute. In the last decade, Dr. Lowry has testified on IR in Alberta, Québec, Hawaii, Massachusetts, Minnesota, North Carolina, and Washington state as well as Ontario. A northeast Ohio native, he now lives in Shorewood Hills, Wisconsin near Madison.