# Evaluation of Ontario Power Generation Inc. and DNNP LP's Proposed Nuclear Payment Amounts Framework

Docket EB-2025-0297

By

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*by*

**Christensen Associates Energy Consulting, LLC**

**May 26, 2026**

## 1 INTRODUCTION

### 1.1 Summary of Report

Ontario Energy Board ("OEB") staff has asked Christensen Associates Energy Consulting ("CA Energy Consulting") to provide expert evidence regarding the total cost benchmarking report provided by ScottMadden Management Consultants[1] ("ScottMadden") and the proposed incentive rate-setting framework, including their proposed stretch factor submitted by Ontario Power Generation Inc. ("OPG" or "the Company") in Docket EB-2025-0297. In this report, we offer analysis regarding ScottMadden's total cost benchmarking study, an evaluation of OPG's proposed stretch factor, and an assessment of OPG's proposed rate setting framework.

ScottMadden's total cost benchmarking analysis computes a measure of generation plant efficiency based on a normalized measure of plant total generating cost ("TGC") per MWh. The methodology divides plants into cohorts based on the calculated measure of efficiency and recommends a stretch factor of 0.3 for OPG using the OEB's stretch factor assignment methodology established in the RRF for Ontario's electricity distributors. ScottMadden has normalized its calculation of TGC per MWh by making adjustments to TGC that account for the impact of the Darlington Refurbishment Program ("DRP") and the effects of plant technology (i.e. CANDU) and age on cost. This normalization also includes an adjustment to MWh to avoid penalizing plants with more frequent planned outages.

We find that ScottMadden's stretch factor recommendation is highly sensitive to the value of their technology adjustment to TGC. We demonstrate that this CANDU adjustment of $539 million is not accurate, and we recommend a higher stretch factor be imposed.[2] Moreover, we argue that ScottMadden's planned outages adjustment to MWh will likely overstate the performance of inefficient plants.

Furthermore, OPG's exclusion of a large percentage of revenue requirement from the "stretch dollar amount" calculation results in a much lower "effective stretch factor" compared to what the Board has approved for distribution utilities under Custom IR. Since OPG uses the same range of stretch factors in the RRF as distribution utilities, if the OEB believes OPG has similar

[1] Ontario Energy Board. *EB-2025-0297. Exhibit F2, Tab 1, Schedule 1, Attachment 4.* December 12, 2025.
[2] The model applies an annual $539 million downward adjustment to TGC for each CANDU plant, effectively removing what is assumed to be a technology-driven cost premium.

efficiency opportunities as distribution utilities operating under Custom IR, we recommend that the OEB incorporates in-service additions from large capital program in the "stretch amount" calculation.

We argue that the flaws with the total cost benchmarking study alone support a stretch factor increase from 0.3 to 0.45, according to the stretch factor methodology set forth by the OEB. If the Board does not adjust the base revenue over which the stretch factor is applied such that it is comparable to distribution utilities in Ontario, we recommend an additional increase of 15 basis points, which reflects a conservative estimate to account for the relatively narrower base revenue to which it is applied. This adjustment would bring the application of a stretch factor to OPG's revenue requirement into alignment with the stretch factor methodology applied to distribution utilities in Ontario.

In the remainder of the report, Section 2 summarizes our critique of ScottMadden's total cost benchmarking analysis. Section 3 provides our evaluation of the application of the stretch factor as well as additional comments on the rate setting framework.

## 1.2 Introduction of Witnesses

The primary authors of this report and the testifying witnesses are Dr. Xueting (Sherry) Wang and Dr. Daniel McLeod. Dr. Wang has co-authored public and non-public research reports in Ontario[3], Maine, and Massachusetts related to incentive regulation. She has assessed the incentive properties of alternative, customized performance-based regulation ("PBR") frameworks as applied to electric utilities. She has reviewed Hydro Ottawa's most recent Custom Incentive Regulation proposal.[4] She holds a PhD in sustainable development from Columbia University specializing in energy economics and a Master of Public Policy degree from the National University of Singapore.

In rate proceedings involving PBR framework, Dr. Daniel McLeod has sponsored testimony, performed industry productivity and cost benchmarking analyses, and co-authored research reports on PBR. He has also reviewed Hydro Ottawa's most recent Custom Incentive Regulation proposal.[5] He holds a PhD in economics from the University of Wisconsin-Madison with a focus in industrial organization and applied econometrics.

[3] "Advancing Performance-based Rate Regulation," Ontario Energy Board, EB-2024-0129.
[4] "Evaluation of Hydro Ottawa's Proposed Custom Incentive Regulation Framework," for the Ontario Energy Board, EB-2024-0115, October 14, 2025.
[5] Ibid.

# 2 TOTAL COST BENCHMARKING ANALYSIS

## 2.1 Background on OPG's Proposed Benchmarking Study and Stretch Factor

The goal of a cost benchmarking study for the purpose of setting a stretch factor is to uncover the regulated company's expected cost efficiency gains during the rate term.[6] A plant achieves cost efficiency growth whenever it is able to produce the same level of output using fewer inputs, all else equal.[7] Similarly, a plant is more cost efficient than a peer if it faces identical operating conditions, which are outside of its control, and is able to produce the same or higher output by using fewer inputs. An appropriate cost benchmarking methodology recovers the company's cost performance using data on its costs, outputs, and exogenous operating conditions. Differences in unit costs (e.g. TGC/MWh) can reflect differences in cost efficiency levels if the proper adjustments are made to unit costs. These adjustments should remove the influence of all uncontrollable factors from TGC and MWh but should retain the influence of all controllable factors.

In its Nuclear Cost Performance Benchmarking report, ScottMadden benchmarks the Darlington Nuclear Generating Station's historical Total Generating Cost ("TGC") per MWh to other plants present in the Electric Utility Cost Group ("EUCG") panel. ScottMadden makes adjustments to both TGC and MWh to remove the influence of factors that are outside of the control of the plant, such that a comparison of adjusted or "normalized" TGC/MWh is closer to a comparison of plant performance. ScottMadden makes three types of adjustments in their report.

First, adjustments to the TGC of all plants are made to remove the effects of plant age and technology on TGC. We refer to this as the "econometric model adjustment." Older plants are likely costlier to maintain all else being equal, and a reactor's underlying technology influences its fuel requirements, maintenance and outage schedules, and fixed costs, which drive differences in TGC.

Second, ScottMadden adjusts OPG's TGC to account for the refurbishment program at Darlington (DRP). We refer to this as the "refurbishment adjustment." ScottMadden removes costs attributed to DNGS such that its costs reflect only the number of operating units. Absent this adjustment, a plant undergoing refurbishment will produce lower MWh, but its TGC will not scale down commensurately given the presence of fixed costs. Consequently, an adjustment is necessary as refurbishment projects will produce higher TGC/MWh without any change in performance.

Finally, ScottMadden adjusts the MWh of all plants to account for differences in planned outages attributable to reactor technology. We refer to this as the "nuclear outages adjustment." A

[6] Throughout this report, CAEC uses the terms "cost efficiency", "cost performance", and "performance" interchangeably.

[7] By "all else equal", we mean all uncontrollable or "exogenous" cost-driving features are held fixed. For instance, an increase in MWh achieved by reducing maintenance outages following a plant refurbishment project is unrelated to cost performance, since it is not driven by operational behavior and is instead related to the age of plant assets. An example of cost efficiency growth could be a reduction in administrative and general labor inputs that does not impact MWh. Cost efficiency growth could also be achieved by increasing the plant's capacity factor, better fuel management, or improved outage management.

reactor that requires more planned outages will produce lower MWh all else equal, increasing its TGC/MWh. A plant operating with such a technology will appear to perform poorly relative to a plant that requires fewer planned outages, and thus requires an adjustment.

We do not take issue with ScottMadden's methodology at a high level. By this, we mean that unit costs normalized in this way are likely to reflect plant performance if the following conditions hold. First, the influence of all *uncontrollable* factors that affect a plant's cost and output are removed from its TGC and MWh. Second, the influence of all *controllable* factors are *not* removed from TGC and MWh. All three adjustments to unit cost described above are appropriate if these two conditions are met. However, a detailed analysis of ScottMadden's workpapers reveals a flawed execution of this methodology that will lead to an inaccurate estimate of DNGS's cost performance. The following section provides a discussion of the issues with the execution of the econometric model adjustment and the nuclear outages adjustment. CAEC does not take issue with the refurbishment adjustment.

Principally, we argue that flaws with the econometric model adjustment support a higher stretch factor. Specifically, we argue that the model's "CANDU coefficient" is not estimated accurately, and even a small change in its value will lead to a higher recommended stretch factor. While we discuss noteworthy issues with ScottMadden's nuclear outages adjustment, that adjustment does not have an impact on our recommended stretch factor for OPG in this proceeding.

## 2.2 Evaluation and Analysis of OPG's Benchmarking Study

### *2.2.1 ScottMadden's Econometric Model Adjustment*

We begin by summarizing the results of ScottMadden's econometric analysis. In order to avoid unfairly penalizing plants with higher uncontrollable costs, ScottMadden adjusts the TGC of each plant using an econometric analysis that estimates and removes the impacts of certain exogenous factors on costs. These two factors are the plant's age and reactor technology[8], which can be PWR, BWR, or CANDU.[9] The measured effects for both of these variables as calculated by ScottMadden are shown below in Table 2.1. Note that the CANDU and PWR coefficients measure how costly these technologies are on average relative to plants with the BWR technology.

**Table 2.1: Relevant Coefficients in ScottMadden's Econometric Analysis**

| | Coefficient | Standard Error | Statistically Significant at 5% level |
|---|---|---|---|
| CANDU (millions $) | 539.5 | 32.1 | Yes |
| PWR (millions $) | 17.3 | 12.1 | No |
| Average Unit Age (000s $) | 77 | 57 | No |

The CANDU and PWR effects in this table are measured annually and the Average Unit Age effect is measured monthly. The CANDU effect of roughly $539 million implies that CANDU plants cost $539 million dollars more per year to operate than BWR plants, controlling for plant age and

[8] MW capacity is also included in the model but no adjustment is made for this variable.
[9] CANDU refers to Canada deuterium uranium, which is a pressurized heavy-water reactor, PWR refers to pressurized water reactor, and BWR refers to boiling water reactor.

capacity. Similarly, the PWR coefficient implies that PWR plants are $17.3 million more costly to operate per year than BWR plants controlling for these variables. To remove the impact of technology on TGC, ScottMadden adjusts TGC for each plant as though it were a BWR plant. This means subtracting $539.5 million from TGC each year for CANDU plants and $17.3 million from TGC for PWR plants. The Average Unit Age effect of $77,000 implies that a plant that is one month older is $77,000 more costly to operate.

The standard errors quantify the degree of uncertainty about these estimated effects. It is common practice to use the coefficient and standard error to compute a confidence interval, which includes all hypothetical coefficients that cannot be rejected by the data with a high degree of confidence. The degree of confidence defines the interval, and is typically chosen to be 95%.[10] A 95% confidence interval is constructed by taking the estimated coefficient plus or minus 1.96 multiplied by the standard error. For example, a measured CANDU coefficient of 539.5 and a standard error of 32.1 implies a 95% confidence interval of $476 million to $603 million.[11] In other words, while ScottMadden measures the CANDU effect at roughly $539 million, they cannot reasonably rule out that the true effect is as low as $476 million or as high as $603 million. The 95% confidence interval for Average Unit Age is -$35,000 to $189,000, meaning that ScottMadden cannot reasonably rule out that the true effect of plant age as constructed is zero. Because ScottMadden cannot statistically infer that the effect of Average Unit Age on TGC is different than zero, this effect is "statistically insignificant." We discuss the implications of this finding below.[12]

## Issues with the CANDU Coefficient

ScottMadden's estimated CANDU effect of $539 million is significantly larger than the same effect from their prior study, which was estimated to be $343.3 million in 2023 dollars.[13] In its response to F2-Staff-324, OPG noted that the difference is driven primarily by including the years 2018-2023 in the analysis. However, OPG notes that the CANDU coefficient is based on "any persistent CANDU-site characteristics that are not separately controlled for."[14] These are *persistent* characteristics, and thus would not explain the significant increase in the coefficient from $343.3 million in ScottMadden's prior study to $539.5 million in the current study.[15]

This finding suggests underlying issues with how ScottMadden's econometric model is specified. Recall that for ScottMadden's econometric adjustment to be valid it must be the case that (1) the influence of all *uncontrollable* factors that affect a plant's cost are removed from its TGC; and (2)

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[10] This leads to a confidence interval that includes the true coefficient in 95% of samples.

[11] OPG calculates the same confidence interval in Ontario Energy Board. *EB-2025-0297. Exhibit L-F2-Staff-324, Page 4.* April 22, 2026.

[12] Note that the $17.3 million dollar difference in average TGC between PWR and BWR plants unexplained by other model variables is also statistically insignificant. Therefore, the CANDU coefficient of $539.5 million can be interpreted as the average difference between CANDU and non-CANDU plants, with other model variables held fixed.

[13] The effect as reported in the 2018 report was $250 million, which was measured in 2017 dollars. This study relied on data from 2009-2017, whereas the current study relies on data from 2006-2023.

[14] Ontario Energy Board. *EB-2025-0297. Exhibit L-F2-Staff-324, Page 4.* April 22, 2026.

[15] Ontario Energy Board. *EB-2025-0297. Exhibit F2, Tab 1, Schedule 1, Attachment 4, Note 3.* December 12, 2025.

the influence of all *controllable* factors are *not* removed from TGC. We discuss violations of both (1) and (2) that will lead to an unreliable CANDU coefficient estimate in ScottMadden's model.

**The CANDU Coefficient Reduces Darlington's TGC for Factors That Are Unique to Bruce and Pickering**

While the influence of uncontrollable factors that affect DNGS's TGC should be removed, only those factors specific to DNGS should affect DNGS's normalization. Factors that increase TGC at Bruce or Pickering but not at DNGS influence the CANDU coefficient in ScottMadden's model and thus will inappropriately affect the TGC normalization for DNGS.

If the Bruce plant, which operates with the CANDU technology, has high TGC that cannot be explained by other variables in the model, the CANDU coefficient will absorb this.[16] For instance, in 2016, the Life-Extension Program began at Bruce Power, which led to a significant observable increase in Bruce's TGC. Because Bruce is one of the three CANDU plants, this resulted in higher average TGC at the CANDU plants. This higher average TGC is reflected in the CANDU coefficient, which is subtracted from DNGS's TGC when it is normalized. In other words, the normalization of the Darlington plant's TGC is impacted by the refurbishment program at the Bruce plant.

The CANDU coefficient will also pick up high costs at Pickering that cannot adequately be explained by the model, such as unit age. Because Pickering has not undergone refurbishment like its CANDU peers, its high costs may in part be the result of this. While plant age is included in ScottMadden's model, it is not reduced following refurbishment to reflect likely lower maintenance and operating costs. Our suspicion that Average Unit Age is not economically meaningful as constructed is supported by the fact that ScottMadden has estimated a statistically insignificant effect of plant age on TGC as shown in Table 2.1, which is consistent with attenuation bias.[17] Thus, the potentially understated $77,000 age effect will not explain the significantly higher costs at Pickering; as a result, those higher costs will get absorbed by the CANDU coefficient, and DNGS's TGC will be incorrectly reduced as a result of this modeling flaw.

**The CANDU Coefficient Likely Reduces Darlington's TGC for Factors That Are Controllable**

ScottMadden's model assumes that the three CANDU plants are no more or less efficient than the 54 non-CANDU plants. However, if the three CANDU plants are less cost efficient than the remaining 54 non-CANDU plants, this difference will get captured by the CANDU coefficient. As a result, DNGS's TGC will be reduced to account for cost-driving factors at CANDU plants that were controllable.

> OPG notes "because the CANDU coefficient is identified from only three sites, it necessarily captures not only reactor-technology differences, but also any persistent

[16] This is because the CANDU coefficient absorbs the difference in average TGC between CANDU plants and non-CANDU plants that cannot be explained by capacity and average unit age. Any other factor aside from capacity and average unit age that explains the difference will get absorbed by the CANDU coefficient.

[17] When an explanatory variable like plant age is measured with error, the coefficient on that variable will be biased toward zero. This bias is known as attenuation bias. See page 322 of Wooldridge, J. M. (2013). Introductory Econometrics: A Modern Approach (5th ed.). Boston, MA: South-Western Cengage Learning.

> CANDU-site characteristics that are not separately controlled for and that are common to those Canadian stations."[18]

However, this includes characteristics that are controllable, and thus the CANDU coefficient will capture the effect on TGC from any differences in controllable factors between CANDU and non-CANDU plants. Moreover, such differences are highly likely given the fact that there are only three CANDU plants, and two of these plants are owned and operated by OPG. Unless OPG and Bruce are as efficient as the average non-CANDU plant, the CANDU coefficient will capture the difference in TGC attributable to this difference in cost efficiency.

For example, suppose TGC at non-CANDU plants averages $750 million and TGC at CANDU plants averages $1.25 billion. Of this difference of $500 million, suppose $250 million is attributable to uncontrollable factors and $250 million is attributable to controllable factors. The CANDU coefficient will be equal to $500 million, or the sum of the effects of both controllable and uncontrollable factors on TGC ($250 million + $250 million). Thus, average "normalized" TGC of CANDU plants will be $1.25 billion – CANDU coefficient ($500 million), which is identical to the average TGC of $750 million at non-CANDU plants. In other words, CANDU plants will mechanically be normalized to appear to be average cost performers. This is supported by the results of ScottMadden's study, which show Darlington and Pickering to be average cost performers after normalization.

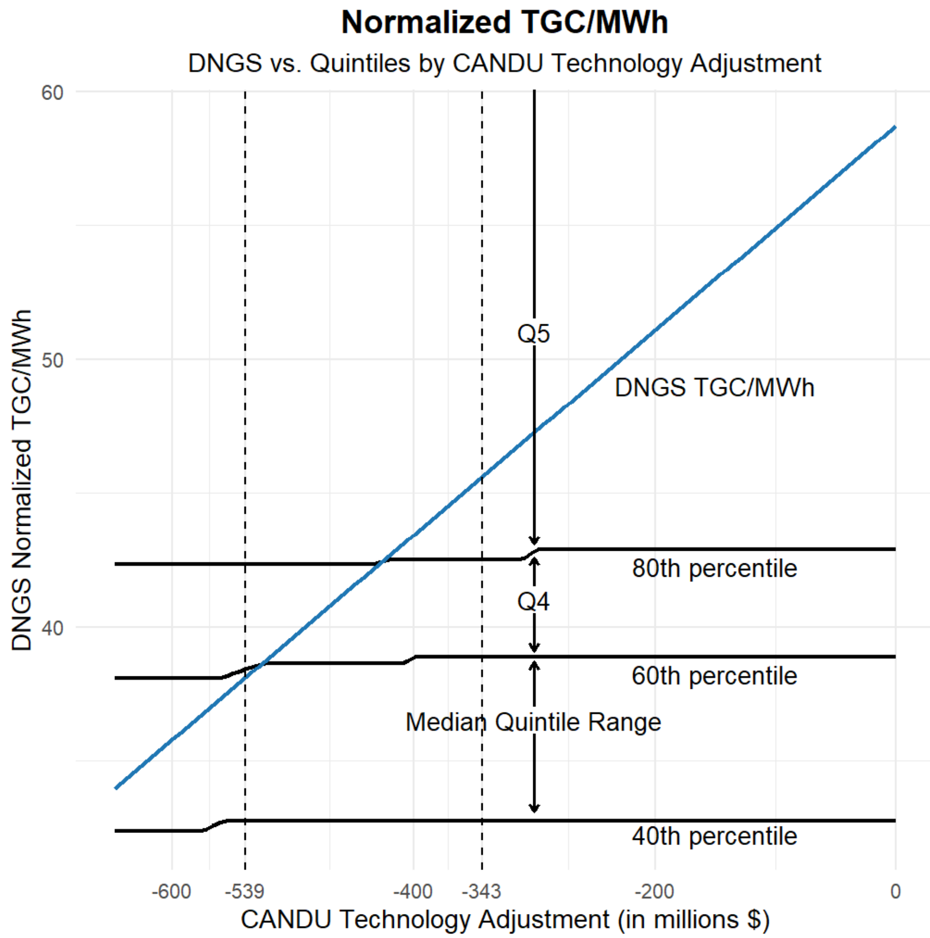
## The Stretch Factor Is Highly Sensitive to the CANDU Coefficient

The above discussion highlights the issues with the CANDU coefficient in ScottMadden's econometric model. DNGS's TGC is being reduced by a CANDU coefficient that incorporates factors unique to Bruce or Pickering and likely accounts for cost-driving factors that are controllable by DNGS. DNGS's TGC normalization is affected by the Life-Extension Program at Bruce and any other factors that explain the average difference in TGC between CANDU and non-CANDU plants. Given that OPG has not adequately explained the increase in the coefficient from roughly $343 to $539 million, it is worthwhile to understand how alternative CANDU coefficients impact the stretch factor recommendation if the coefficient of $539 million is not accurate.

To illustrate the impact of an alternative CANDU technology coefficient on the stretch factor, we recalculate DNGS's relative normalized TGC/MWh metric as depicted in Chart 16 of Exhibit A1 for different values of the coefficient. The results of this analysis are shown in Figure 2.1.

[18] Ontario Energy Board. *EB-2025-0297. Exhibit L-F2-Staff-324, Page 4.* April 22, 2026.

**Figure 2.1: Impact of CANDU Technology Adjustment on DNGS's Cost Performance**



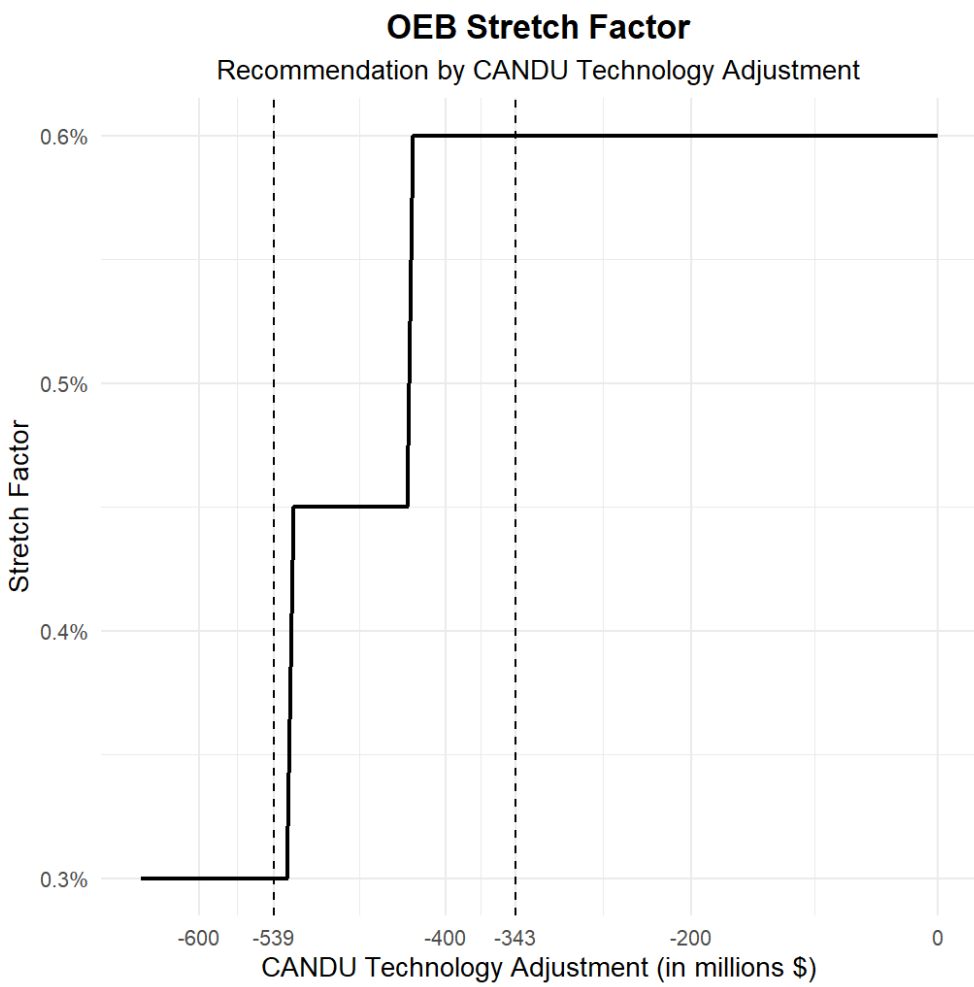

The blue line shows DNGS's TGC/MWh for different values of the CANDU coefficient. Note that the adjustment is shown as a negative number since TGC is reduced by the adjustment. Two values of this coefficient are marked by vertical bars. The first is the estimated adjustment of $539 million from the current ScottMadden study. The second is the adjustment of $343 million from ScottMadden's prior study. The black horizontal curves depict the third, fourth, and fifth quintiles, with the third quintile being equivalent to the median quintile range. At the coefficient of $539 million, DNGS's normalized TGC/MWh falls just below the 60$^{th}$ percentile, and is thus within the median quintile range. This is the result as shown in Chart 16 of Exhibit A1. However, at the coefficient of $343 million, DNGS's TGC/MWh is far above the 80$^{th}$ percentile, placing it in the fifth quintile.

> OPG states "As shown in Chart 16 below, ScottMadden's econometric analysis concludes that the TGC/MWh of Darlington over the 2021-2023 historic period was $39.58, once the impacts of the DRP and planned outages are accounted for. This performance puts the station in the median or third quintile of the Electric Utility Cost Group ("EUCG") peer group. Accordingly, OPG proposes a nuclear stretch factor of 0.3% based on the range of stretch factors set out by the OEB in the RRF."[19]

[19] Ontario Energy Board. *EB-2025-0297. Exhibit A1, Tab 3, Schedule 2, Page 32.* December 12, 2025.

The referenced range of stretch factors set out by the OEB in the RRF implies a stretch factor of 0.45% for plants within the fourth quintile and 0.6% for plants within the fifth quintile. Figure 2.2 shows that if the CANDU coefficient is even slightly overstated and the true coefficient is between $426 million and $523 million, a stretch factor of 0.45% would be recommended. If the coefficient is lower than $426 million as it was in the 2018 study, a stretch factor of 0.6% would be recommended.

**Figure 2.2: Stretch Factor Sensitivity to CANDU Technology Adjustment**




This analysis demonstrates that DNGS's measured performance and the corresponding stretch factor are highly sensitive to the CANDU technology coefficient and, given the flaws in the CANDU technology coefficient identified above, suggests that a higher stretch factor should be imposed.

### *2.2.2 Adjustment to Planned Outages may not be appropriate*

ScottMadden considers an additional normalized TGC/MWh metric that "corrects" for differences in the rate of planned outages across sites attributable to differences in reactor technology. They note:

> "All reactor types have planned maintenance outages on either 18, 24, 30, or 36-month cycles. Planned maintenance outages for PWRs and BWRs are incorporated into refueling cycles and occur every 18 or 24 months. Planned maintenance outages for CANDU reactors occur every 24, 30, or 36 months. Work to significantly extend the operating life of a plant (life-extension activities) is also approached differently across technologies. For PWR and BWR plants, it is more common to complete this work as part of planned refueling and maintenance outages over a series of multiple outages to minimize time in outage. The scope for this work also differs from one plant to the next due to differences in plant design, market construct, and other factors. Comparable life-extension activities for CANDU plants largely occur during long-duration refurbishment outages where multiple, major plant components are replaced, though some related work can also be incorporated into more frequently recurring planned maintenance outages."[20]

The following table summarizes the distribution of planned outage rates across technologies. The minimum planned outage rate in the data is 2.7%, and ScottMadden normalizes all plants' MWh as if it operated at this rate. DNGS's planned outage rate is 7.1%, which falls between the planned outage rates of its two CANDU peers.

**Table 2.2: Planned Outage Variation**

| | Percentile | | | | |
|---|---|---|---|---|---|
| Technology | Min | 0.25 | Median | 0.75 | Max |
| BWR | 2.7% | 3.9% | 5.5% | 6.5% | 9.6% |
| CANDU | 6.5% | - | 7.1% | - | 13.6% |
| PWR | 3.9% | 6.2% | 6.9% | 8.0% | 9.5% |

While ScottMadden notes that "The scope for this work also differs from one plant to the next due to differences in plant design, market construct, and other factors", the variation in planned outage rates *within* technologies is far greater than the variation between technologies. For instance, the median planned outage rate varies between 5.5% and 7.1% across technologies – a difference of 160 basis points. But the average inner quartile range across the three technologies (between the 25th and 75th percentiles) spans 263 basis points. Thus, ScottMadden's reasoning for the planned outages adjustment fails to adequately attribute most of the variation in planned outage rates to factors outside of the plant's control. It is possible that much of this variation is controllable, and thus this approach may be overstating the performance of plants with high planned outage rates.

[20] Ontario Energy Board. *EB-2025-0297. Exhibit F2, Tab 1, Schedule 1, Attachment 4, page 11.* December 12, 2025.

### *2.2.3 Impact on the Recommended Stretch Factor*

As shown in Figure 2.2, even a slight reduction in the CANDU coefficient from $539 million to $523 million would result in a stretch factor recommendation of 0.45.[21] At the very least, given that the CANDU coefficient is inappropriately reducing TGC at Darlington to account for costs at the Bruce plant resulting from the Life-Extension Program, a corrected coefficient lower than $523 million is reasonable. Given the other flaws with the econometric model discussed above that likely overstate the TGC normalization applied to DNGS, we recommend a stretch factor increase from 0.3 to 0.45. While we have highlighted our concerns with the nuclear outages adjustment, we do not find that it has a material impact on the stretch factor recommendation. This increase in the recommended stretch factor from 0.3 to 0.45 does not incorporate considerations regarding how the stretch factor is applied, which is discussed below in Section 3.

[21] This threshold of $523 million is approximately the same regardless of whether the nuclear outages adjustment is applied to MWh.

# 3 OVERALL RATE SETTING FRAMEWORK

## 3.1 Background on OPG's Proposed Application of the Stretch Factor

The proposed framework uses five future test years with individual forecasted revenue requirements beginning in 2027. A portion of the revenue requirements are adjusted by a stretch factor from the second year (2028) onward. ScottMadden's econometric analysis puts the Darlington Nuclear Generating Station in the median or third quintile of the EUCG peer group. Based on the range of stretch factors set out by the OEB in the RRF, OPG proposes a nuclear stretch factor of 0.3%. However, this stretch factor of 0.3% does not apply to the total revenue requirements. OPG proposes that approximately 46% of the revenue requirements from 2028 to 2031 be excluded from the application of the 0.3% stretch factor for OPG nuclear facilities.

Table 2.1 compares the nuclear facilities' revenue requirement subject to the stretch factor and the total revenue requirement in the current proposal (2028-2031) against the settlement proposal from OPG's previous application (2023-2026). The percentage of revenue requirement subject to the stretch factor drops significantly.

**Table 3.1: Comparison of Revenue Requirement Subject to Stretch Factor**

| | 2023-2026 | 2028-2031 |
|---|---|---|
| Total Revenue Requirement ($M) | 12,697[22] | 19,630[23] |
| Revenue Requirement Included in Stretch ($M) | 8,336[24] | 10,565[25] |
| Percentage Subject to Stretch Factor | 66% | 54% |

A major revenue component excluded from the application of the stretch factor is the in-service addition of the units that were refurbished through the Darlington Refurbishment Program after its completion, which accounts for $5,373 million, or 27% of the total revenue requirement for OPG nuclear facilities from 2028 to 2031. OPG has proposed a similar treatment for the units refurbished through Pickering Refurbishment Program, with $743 million of the capital related revenue for units refurbished through the Pickering Refurbishment Program being excluded from the application of the stretch factor in 2031 accounting for 12.9% of that year's revenue requirement.

Further, none of the $2,385 million[26] Darlington New Nuclear Program 2028-2031 revenue requirement is subject to a stretch factor. This means that the majority of the capital related revenue requirement in 2031, when the first units of both Darlington New Nuclear Program and Pickering Refurbishment Program are projected to be operational, will not be subject to a stretch

[22] Ontario Energy Board. *EB-2020-0290, Payment Amount Order*, *Appendix A, Table 2-5, Line 24*. January 27, 2022.

[23] This number excludes the revenue requirement of DNNP. Source: Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 1, Schedule 1, Table 2, Line 24, columns (b) to (e).* March 10, 2026.

[24] Ontario Energy Board. *EB-2020-0290, Payment Amount Order*, *Appendix A, Table 7, Line 23*. January 27, 2022.

[25] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 3, Schedule 1, Table 2, Line 22, columns (b) to (e).* March 10, 2026.

[26] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 1, Schedule 1, Table 2a, Line 22, column (b) to (e).* March 10, 2026.

factor. Table 3.2 summarizes the share of capital-related revenue requirement subject and not subject to a stretch factor in 2031. In particular, the table shows that 70% of capital-related revenue will not be subject to a stretch factor in 2031.

**Table 3.2: Comparison of Capital-Related Revenue Requirement Subject to Stretch Factor in 2031**

| Revenue Component | | Revenue |
|---|---|---|
| **Capital Related Revenue Requirement Subject to Stretch Factor** | | |
| a | Total Darlington and Operations & Project Support Capital Related Revenue Requirement Subject to Stretch Factor ($M) | 1,055.4[27] |
| b | Total Pickering Capital Related Revenue Requirement Subject to Stretch Factor ($M) | 128.1[28] |
| c | Income Tax Expense – Capital Cost Allowance ($M) | (226.2)[29] |
| **d = a + b + c** | **Total Capital Related Revenue Requirement Subject to Stretch Factor ($M)** | **957.3** |
| **Capital Related Revenue Requirement Not Subject to Stretch Factor** | | |
| e | Darlington New Nuclear Program Capital Related Revenue Requirement ($M)[30] | 704.6[31] |
| f | Total DRP Capital Related Revenue Requirement Not Subject to Stretch Factor ($M) | 1,292.9[32] |
| g | Total PRP Capital Related Revenue Requirement Not Subject to Stretch Factor | 743.4[33] |
| h | Income Tax Expense – Capital Cost Allowance Not Subject to Stretch Factor | (493.1)[34] |
| **i = e + f + g +h** | **Total Capital Related Revenue Requirement Not Subject to Stretch Factor ($M)** | **2,247.8** |
| **j = d + i** | **Total Capital Related Revenue Requirement ($M)** | **3,205.1** |
| **i/j** | **Share of Capital Related Revenue Requirement Not Subject to Stretch Factor** | **70%** |

[27] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 3, Schedule 1, Table 2, Line 16, column (e).* March 10, 2026.
[28] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 3, Schedule 1, Table 2, Line 20, column (e).* March 10, 2026.
[29] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 3, Schedule 1, Table 2, Line 21, column (e).* March 10, 2026.
[30] Includes amortization expenses, which may not be strictly capital-related, however, any such amounts are not expected to materially affect the calculation.
[31] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 1, Schedule 1, Table 2a, Lines 12 and 15, column (e).* March 10, 2026.
[32] Ontario Energy Board. *EB-2025-0297. Exhibit L-A1-Staff-294, Attachment 1, Table 1, Line 13, column (e). April 22, 2026.*
[33] Ontario Energy Board. *EB-2025-0297. Exhibit L-A1-Staff-294, Attachment 1, Table 1, Line 17, column (e). April 22, 2026.*
[34] Ontario Energy Board. *EB-2025-0297. Exhibit L-A1-Staff-294, Attachment 1, Table 1, Line 18, column (e). April 22, 2026.*

As more Pickering Refurbishment Program and Darlington New Nuclear Program units come into service and are included in the rate base, the share of capital related revenue requirement subject to the stretch factor will decrease further.

Other major revenue requirement components excluded from the application of the stretch factor include fuel expenses and concurrent cost recovery revenues for the PRP and the DNNP.

## 3.2 Evaluation of Strech Factor Application

A stretch factor (also called the consumer dividend) transfers to customers a portion of the company's expected efficiency gains over the rate term. The previous section reviewed the total cost benchmarking study. This section explains how the stretch factor is typically set and which components of the revenue requirement it should apply to. It outlines the theory and Ontario precedent for setting the stretch factor based on the results of a cost benchmarking study, contrasts this approach with those used in other jurisdictions, and assesses OPG's proposed application of the stretch factor in this context.

### *3.2.1 Setting the Stretch Factor*

While the academic literature has alluded to a connection between cost benchmarking results and stretch factors,[35] there is no explicit formula in the academic literature that translates the total cost benchmarking results into a specific stretch factor value. The efficiency ranking from total cost benchmarking studies provides qualitative information on whether the company should be subject to a higher or lower stretch factor, but setting the stretch factor itself typically requires some degree of expert judgement. Since the stretch factor represents a fraction of the expected cost efficiency gains to be achieved during the rate term, the magnitude of the stretch factor should be proportional to these expected efficiency gains.

There is a difference in interpretation between the stretch factor applied to an indexed cap rate plan and a plan in which the future test year revenue requirements are forecasted by the utility. Under a standard price cap, the addition of a stretch factor slows the growth of prices relative to the industry average. A positive stretch factor implies that the company is expected to achieve productivity growth in excess of what is reflected by the X factor, which typically represents historical industry productivity growth. If instead the utility forecasts future revenue requirements, the stretch factor can be interpreted as expected cost savings or productivity gains compared to the company's own forecast.

Price cap frameworks defined by an "I-X" formula typically decompose expected productivity gains into those that reflect the industry trend (represented by the productivity factor) and those that reflect the company's deviation from that trend (the stretch factor). In a forecasted rate plan, it is unclear whether the utility's forecast already embeds productivity trends observed across the industry (unlike in a standard indexed cap approach which clearly defines both industry productivity in the productivity factor and company-specific deviations from the industry average in a stretch factor). In Appendix A, we describe an example of how Ofgem applies a

[35] Lowry, M.N., Getachew, L., Hovde, D. *Econometric Benchmarking of Cost Performance: The Case of US Power Distributors*. The Energy Journal 26 (3). 2005. p. 75–92

stretch factor to distribution utilities when the total revenue requirements are not escalated by an indexed cap.

In Sections 3.2.2 and 3.2.3, we review the precedent of how stretch factors are set both for the OEB and other jurisdictions. While many jurisdictions reference cost benchmarking studies to set the stretch factor, to our knowledge, few jurisdictions aside from the OEB have an explicit pre-set correspondence between total cost benchmarking result and the stretch factor. We infer that other jurisdictions rely heavily on precedent. However, no jurisdiction has established a mechanism that links cost benchmarking results to a stretch factor on the basis of clear economic theory.

### *3.2.2 OEB Precedent in Regulation of Other Utilities*

The OEB assigns stretch factors to distribution utilities based on the results of the total cost benchmarking study, as shown in Table 3.3 below, established in a 2013 OEB report:

**Table 3.3: Demarcation Points and Stretch Factor Values**[36]

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

For distribution utilities that have chosen a "Price Cap IR", the stretch factor is updated each year based on the latest data and total cost benchmarking analysis conducted by Pacific Economics Group ("PEG") during the five-year term.[37] Under Price Cap IR, as the base distribution rate recovers the distributor's base revenue requirement in its entirety, the stretch factor's efficiency expectation applies to the full base revenue requirement rather than to selective cost components.

Under Ontario's Custom IR, utilities are required to submit alternative benchmarking studies and may propose individualized stretch factors. Currently, three distribution utilities – Hydro One Networks, Hydro Ottawa and Toronto Hydro – operate under Custom IR and two additional distribution utilities – Alectra and Elexicon – have submitted a Custom IR application.[38] Table 3.4 summarizes the stretch factor information for Ontario utilities operating under or having applied for Custom IR.

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[36] "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors." *Report of the Board.* Ontario Energy Board. December 4, 2013. EB-2010-0379.
[37] "Filing Requirements For Electricity Distribution Rate Applications -2025 Edition for 2026 Rates" Chapter 3, Ontario Energy Board, June 19, 2025, p. 6.
[38] Hydro One Networks transmission rates are also set under Custom IR.

**Table 3.4: A summary of Stretch Factors of Distribution Utilities Under Custom IR in Ontario**

<table>
<tr><th>Utility</th><th>Stretch Factor Applied to O&M Funding</th><th>Stretch Factor Applied to Capital Related Funding</th><th>Revenue Subject to Stretch Factor</th></tr>
<tr><td>Toronto Hydro-Electric System Limited</td><td>0.6%</td><td>0.6% + 0.3% Incremental Capital Stretch Factor[39]</td><td rowspan="6">All base revenue requirement[40]</td></tr>
<tr><td rowspan="2">Hydro One Networks Inc.</td><td>Transmission Stretch Factor of 0.15%</td><td>Transmission Stretch Factor of 0.15% and Supplemental Stretch Factor on Capital of 0.20%[41,42]</td></tr>
<tr><td>Distribution Stretch Factor of 0.45%</td><td>Distribution Stretch Factor of 0.45% and Supplemental Stretch Factor on Capital of 0.20%[43,44]</td></tr>
<tr><td>Hydro Ottawa Limited</td><td>0.45%</td><td>0.45% + 0.225% Incremental Capital Stretch Factor[45]</td></tr>
<tr><td>Alectra Utilities Corporation</td><td colspan="2">Proposed 0.15%[46]</td></tr>
<tr><td>Elexicon Energy Inc.</td><td colspan="2">Proposed 0.15%[47]</td></tr>
</table>

For the three distributors currently operating under Custom IR, the approved stretch factors are no lower than those obtained from PEG's total cost benchmarking methodology at the time of each filing.[48] This is consistent with the OEB's general expectation that the X-factor under Custom IR should be no lower than the OEB-approved X-factor under Price Cap IR.[49] In contrast, the two utilities currently proposing Custom IR (Alectra and Elexicon) have each proposed a

[39] Ontario Energy Board. *EB-2023-0195. Toronto Hydro-Electric System Limited Settlement Proposal.* August 16, 2024. p. 9.
[40] Deferral and variance account balances are reconciled separately and are not subject to the stretch factor.
[41] Ontario Energy Board. *EB-2021-0110. Settlement Proposal.* October 24, 2022. p. 55-56.
[42] Ontario Energy Board. *EB-2021-0110. Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research.* June 11, 2022. p. 1.
[43] Ontario Energy Board. *EB-2021-0110. Settlement Proposal.* October 24, 2022. p. 55-56.
[44] Ontario Energy Board. *EB-2021-0110. Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research.* June 11, 2022. p. 1.
[45] Ontario Energy Board. *EB-2024-0115. Settlement Proposal.* January 16, 2026. p. 17 and 21.
[46] Ontario Energy Board. *EB-2025-0252. Exhibit 1, Tab 6, Schedule 2, Attachment 1-3. Clearspring Energy Advisors Econometric Benchmarking and Incentive Regulation Parameter Study.* October 24, 2025. p. 2
[47] Ontario Energy Board. *EB-2025-0312. Exhibit 1, Tab 5, Schedule 1.* December 19, 2025. p. 3.
[48] Pacific Economics Group, Empirical Research in Support of Incentive Rate-Setting: 2021, 2023, and 2025 update, Report to the Ontario Energy Board.
[49] Ontario Energy Board. *Handbook to Utility Rate Applications.* October 13, 2016. p. 26

lower stretch factor (0.15%) than that indicated by the most recent annual benchmark update (0.30%).[50]

### *3.2.3 Precedent In Other Jurisdictions*

Table 3.5 provides a summary of stretch factors adopted in other jurisdictions. Appendix A provides a detailed description of how stretch factors were determined and whether a given stretch factor applies to all or only a subset of the utility's revenues.

**Table 3.5: Stretch Factors Applied in Other Jurisdictions**

| Utility (No. of Utilities) | Stretch Factor | Type of Utility |
|---|---|---|
| FortisBC Inc. (Electric) | 0.25%[51] | Vertically Integrated |
| FortisBC Energy Inc. (Gas) | 0.27%[52] | Vertically Integrated |
| Alberta Distribution Companies (4) | Unknown (Integrated into X Factor)[53] | Distribution |
| Hawaiian Electric Companies (3) | Stretch = 0.22% * Compounding ARA Revenues + $6.61 Million[54,55] | Vertically Integrated |
| Eversource (Massachusetts) | Consumer Dividend = 0.25% when inflation >2%[56] | Distribution |
| National Grid (Massachusetts) | Consumer Dividend = 0.40% when inflation >2%[57] | Distribution |
| Fitchburg Gas & Electric (Massachusetts) | Consumer Dividend = 0.25% when inflation >2%[58] | Distribution |
| Eversource (New Hampshire) | Consumer Dividend = 0.15% when inflation > 2%[59] | Distribution |
| Great Britain Distribution Companies (14) | Catch-up efficiency based on company's relative performance to 75-85% percentile[60] | Distribution |

[50] Pacific Economics Group Research. *Empirical Research in Support of Incentive Rate-Setting: 2024 Benchmarking Update. Table 5 – Stretch Factor Assignments by Group.* August 2025.
[51] British Columbia Utilities Commission. *Order G-69-25 and G-70-25.* March 18, 2025. p.46.
[52] Ibid.
[53] Alberta Utilities Commission.*2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities.* October 4, 2023. p. 43.
[54] The stretch factor, or consumer dividend, in Hawaii equals a 0.22% addition to the I-X revenue cap formula applied to the Annual Revenue Adjustment ("ARA"), along with an additional $6.61 million "Savings Commitment" arising from the company's management audit.
[55] Hawaii Public Utilities Commission. *Docket No. 2018-0088. Order No. 37557.* January 4, 2021.
[56] Massachusetts Department of Public Utilities. *D.P.U. 22-22. Order*. November 30, 2022. p. 59.
[57] Massachusetts Department of Public Utilities. *D.P.U. 23-150. Order*. September 30, 2024. p. 90.
[58] Massachusetts Department of Public Utilities. *D.P.U. 23-80. Order*. June 28, 2024. p. 43.
[59] New Hampshire Public Utilities Commission. *DE 24-070. Order No. 28,170.* July 25, 2025. p. 2.
[60] Ofgem. *RIIO-ED2 Final Determinations Overview document.* November 30, 2022. p. 28.

### *3.2.4 Discussion and Recommendation*

As shown in Table 3.4, each distribution utility under Custom IR derives the "stretch dollar amount" by applying an assigned stretch factor to the utility's total base service revenue requirement. This stretch factor is at least as high as what it would be if the utilities were under a price cap, obtained from PEG's total cost benchmarking methodology at the time of each filing. For utilities under Price Cap IR, the stretch factor is a component of the X-factor in the Price Cap Index (I – X) applied to base distribution rates; because those rates recover the entire base revenue requirement, the stretch factor applies to the full base revenue requirement.

OPG's proposal derives the "stretch dollar amount" by applying the stretch factor to a much smaller revenue base than the distribution utilities in Table 3.4. This approach is not inherently unreasonable. It can be viewed as a bottom-up approach to arrive at the "stretch dollar amount" by looking at the extent to which each category of cost is controllable and how much cost savings may be expected for each cost category. However, we have concerns regarding aspects of OPG's proposal, as follows:

1. While OPG is applying a similar correspondence between total cost benchmarking results and the stretch factor set by the OEB for electricity distribution utilities (see Table 3.3), OPG proposes to exclude approximately 46% of 2028-2031 total base revenue requirement related to its nuclear facilities from the application of the stretch factor. In addition, OPG proposes to exclude all of the $2,385 million DNNP 2028-2031 revenue requirement from adjustment by the stretch factor. Due to the difference in the "base revenue" that the stretch factor adjusts, OPG's proposal results in a much lower relative revenue reduction than distribution utilities under Custom IR, an effect that is amplified because reductions in earlier years persist in future years. In other words, OPG has proposed a lower "effective stretch factor."

   The in-service addition of capital investments to the units that were refurbished under the DRP, as discussed in Section 3.1, constitute the major revenue requirement exclusion from stretch factor application during the 2027-2031 rate term.[61] However, we understand that stretch factors in Ontario generally apply to utility *total* base service revenue requirements, including the in-service addition of large capital projects. For both OPG and distribution utilities under Custom IR, the capital related revenue requirement associated with these large capital projects may be less controllable compared to some other cost categories. The omission of certain revenue categories from adjustment under OPG's stretch factor would constitute a departure from the OEB's application of the stretch factor concept to distribution utilities in the province. In its application, OPG states "[s]imillar to the DRP and the PRP, the DNNP is a large, singular investment to build a new nuclear facility that will not be in `steady state' operations during the IR term."[62] However, given the completion of the DRP, its associated capital-related revenue requirement becomes part of the "used and useful" rate base. We are not convinced that the "non-steady state" operation still applies to the capital-related revenue requirement after in-service addition.

2. The proposed stretch factor approach weakens the link between OPG's cost performance and revenue requirement. Total cost benchmarking provides a way for regulators to

[61] Exhibit L-A1-Staff-294, Attachment 1, Table 1.
[62] Exhibit A1-3-2, p31.

> gauge a regulated utility's cost performance relative to the utility's industry. This is especially useful when revenue requirements are based on the company's forecast. Linking the results of the utility's relative cost performance with the utility's revenue requirement provides the company an added incentive to achieve cost efficiency growth as better cost performance in the current rate term will increase the utility's allowed revenue requirement in the following rate term. A lower "effective stretch factor" reduces this effect.

As shown in Section 3.2.3, there is no universal rule to set the stretch factor across jurisdictions. However, there are some guiding principles that we recommend for consideration. As we explained previously, for a company under a forecasted rate plan, the "stretch dollar amount" can in theory be derived using a bottom-up approach. However, the OEB may want to take into consideration that this means a lower "effective stretch factor" is applied compared to distribution utilities operating under Custom IR in Ontario.[63]

Since OPG uses the same range of stretch factors in the RRF as distribution utilities, if the OEB believes OPG has similar efficiency opportunities as distribution utilities operating under Custom IR, we recommend that the OEB incorporates in-service additions from large capital program in the "stretch amount" calculation. Alternatively, if the OEB does not adjust the base revenue over which the stretch factor is applied (such that it is comparable to distribution utilities in Ontario), we recommend an additional increase of 15 basis points to account for the lower effective stretch factor proposed by OPG.

As shown in Table 3.6, under the current proposal, the "effective stretch factor" is approximately 0.16% in 2028, calculated using only the total revenue requirement for OPG nuclear facilities. Including the revenue requirement for DNNP would further reduce the effective stretch factor. According to our analysis in Section 2, we recommend an upward adjustment of the stretch factor from 0.3% to 0.45%. Simply including the in-service addition of the capital investments to the units that were refurbished under the DRP to the base of the stretch calculation results in a stretch adjustment of $16.7 million. We can translate this dollar amount into a percentage to obtain a stretch factor of 0.72%. If we apply the same calculations in Table 3.6 to 2029 to 2031, the stretch factor for each year based on OPG's proposed base will be between 0.6% to 0.7%. Therefore, an increase from 0.45% to 0.6% reflects a conservative adjustment to account for the narrower base to which it applies.

[63] For example, as discussed in Appendix A, the DPU noted as the proposed customer dividend applied only to O&M-related revenue, rather than total revenue, the customer dividend percentage should be higher than proposed.

**Table 3.6: Illustrative Calculation of Stretch Factor for 2028**

| | | |
|---|---|---|
| **OPG Proposal** | | |
| a | Revenue Requirement Used in Stretch Amount Calculation ($M) | 2,318.1[64] |
| b | Stretch Factor Applied | 0.30% |
| c=a*b | Stretch Adjustment ($M) | 7.0 |
| d | Total Revenue Requirement for OPG Nuclear Facilities ($M) | 4264.4[65] |
| **e = c/d** | **"Effective Stretch Factor" with Total Revenue Requirement as the Base** | 0.16% |
| **Recommended Stretch Factor Adjustment** | | |
| f | In-Service Addition of Capital Investments to the Units Refurbished under DRP ($M) | 1391.5[66] |
| **g=a+f** | Revenue Requirement Used in Stretch Amount Calculation ($M) | 3,709.6 |
| h | Stretch Factor Applied | 0.45% |
| **i=g*h** | Stretch Adjustment ($M) | 16.7 |
| **j=i/a** | **Stretch Factor Based on OPG's Proposed Base** | **0.72%** |

## 3.3 Additional Comments on the Rate Setting Framework

OPG is proposing to undertake two large capital projects: the PRP and the new DNNP. Variance accounts associated with these projects were established pursuant to amendments to Ontario Regulation 53/05. When a cost overrun is recoverable through a variance account, the marginal incentive to avoid that overrun is materially reduced, and when an underrun must be returned, the incentive to pursue cost efficiency is similarly muted. In OPG's case, however, certain variance accounts — including the Darlington New Nuclear Project Variance Account re Development and Pickering B Refurbishment Project Variance Account, among others — are mandated by Ontario Regulation 53/05 rather than established at the OEB's discretion. Given this constraint, there are limited tools available to incentivize cost efficiency, making prudency review a more critical component of regulatory oversight.

The proposal also includes an asymmetrical Earnings Sharing Mechanism (ESM) that shares 50% of any regulated earnings that exceed 100 basis points above the OEB-approved ROE rate. This ESM can serve as a guardrail against factors such as forecasting errors or external shocks that result in a higher actual ROE than allowed ROE. For example, if the company's forecast turns out to be higher than the actual costs, a portion of the higher earnings will be shared with customers. However, an ESM dampens cost efficiency incentives because the company does not retain all of its efficiency gains if it must share those gains with customers. Also, if the company's cost increases due to inefficiency, the company is not likely to have any earnings above the allowed ROE to share. The proposed ESM, which contains a 100 basis point deadband, represents a trade-off between risk insurance and utility incentive.

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[64] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 3, Schedule 1, Table 2, Lines 22, column (b).* March 10, 2026.
[65] Ontario Energy Board. *EB-2025-0297. Exhibit I1, Tab 1, Schedule 1, Table 2, Lines 24, column (b).* March 10, 2026.
[66] Ontario Energy Board. *EB-2025-0297. Exhibit L-A1-Staff-294, Attachment 1, Table 1, Line 13, column (b). April 22, 2026.*

# 4 CONCLUSIONS

This report evaluates the total cost benchmarking analysis conducted by ScottMadden and offers the following key critiques.

1. ScottMadden's econometric model adjustment to TGC is flawed. DNGS's TGC is being reduced to account for any factor not included in the model that explains the average difference in TGC between CANDU and non-CANDU plants, including factors unrelated to DNGS like the Life-Extension Program at Bruce, as well as controllable factors like differences in operational performance. We find that even a small reduction in ScottMadden's reported CANDU coefficient from $539 million to $523 million supports a stretch factor increase from 0.3 to 0.45.

2. We also find that ScottMadden's reasoning for a planned outages adjustment to MWh based on variation in plant technology is inconsistent with the data, which shows significant variation in planned outage frequency for each plant technology. Thus, ScottMadden's approach will likely overstate the performance of plants with frequent planned outages that are unrelated to the plant's technology. While this does not have a material impact on our recommended stretch factor for OPG, we argue that total cost benchmarking results should be reported without this adjustment.

A key issue with OPG's application of their stretch factor is that while OPG uses the range of stretch factors set out by the OEB in the RRF, it only applies the stretch factor to a much smaller share of their revenue requirement compared to distribution utilities under Custom IR. For OPG nuclear facilities, the proposed stretch factor only applies to 54% of the total base revenue requirement from 2028 to 2031. None of the $2,385 million DNNP 2028-2031 revenue is subject to the stretch factor. About 70% of capital related revenue requirement in 2031 is excluded from stretch factor application. The reduced "effective stretch factor" also weakens the link between OPG's cost performance and its revenue requirement, thereby diminishing the incentive for the utility to improve cost efficiency. If the OEB believes OPG has similar efficiency opportunities as distribution utilities operating under Custom IR, we recommend that the OEB incorporates in-service additions from large capital program in the "stretch amount" calculation.

We argue that the flaws with the total cost benchmarking study support a stretch factor increase from 0.3 to 0.45, according to the stretch factor methodology set forth by the OEB. If the Board does not adjust the base revenue over which the stretch factor is applied such that it is comparable to distribution utilities in Ontario, we recommend an additional increase of 15 basis points, representing a conservative adjustment to account for the relatively narrower base revenue to which the stretch factor applies. This adjustment would bring the application of a stretch factor to OPG's revenue requirement into alignment with the stretch factor methodology applied to distribution utilities in Ontario.

# APPENDIX A: DEVELOPMENT OF STRETCH FACTORS IN OTHER JURISDICTIONS

FortisBC Inc. (“FBC”) and FortisBC Energy Inc. (“FEI”)

Under FortisBC's 2025–2027 Rate Framework approved by the British Columbia Utilities Commission (“BCUC”), base O&M for both FEI and FBC is subject to an index-based formula that escalates a per-customer unit cost by inflation less a productivity factor. For FEI, Growth capital is also formula-driven; remaining capital (Sustainment and Other) is forecasted. For FBC, all capital is forecasted rather than formula driven.[67]

FortisBC's expert, Dr. Lawrence Kaufmann, conducted O&M partial factor productivity (“PFP”) studies using 15 years of U.S. industry data and recommended X-Factors of 0.38 percent for FEI (0.28 percent PFP plus a 0.10 percent stretch factor) and 0.20 percent for FBC (0.20 percent PFP and zero stretch factor). His stretch factor recommendations were informed by the BCUC's previously approved X-Factors, O&M cost benchmarking evidence, and the savings achieved under prior incentive plans. The BCUC accepted the PFP values but rejected the proposed stretch factors, approving instead 0.27 percent for FEI and 0.25 percent for FBC, resulting in total X-Factors of 0.55 percent and 0.45 percent, respectively. The Panel pointed to formula O&M savings realized over the 2020–2024 term as evidence that neither utility had reached a productivity level precluding further improvement and emphasized that during a period of heightened uncertainty driven by the energy transition and affordability concerns, utilities should continue to strive for increased productivity.[68]

Alberta Distribution Companies

Under the Alberta Utilities Commission’s (“AUC”) third-generation PBR (“PBR3”) plan for 2024-2028, rates are adjusted annually by an I-X index. Capital is funded through a combination of the I-X mechanism, a K-bar mechanism for routine capital additions, and capital tracker for extraordinary projects. The AUC approved a total X-Factor of 0.1 percent, inclusive of both industry total factor productivity (“TFP”) growth and a stretch factor, plus a separate 0.3 percent X-factor premium as a benefit-sharing provision, resulting in a combined 0.4 percent.[69]

In setting the stretch factor, the AUC emphasized that, unlike the industry TFP component, its magnitude is largely a matter of regulatory judgment informed by precedent rather than a mechanical formula. While recognizing arguments that benchmarking could be used to calibrate stretch factors, including econometric studies filed by Pacific Economics Group (“PEG”), the AUC declined to rely on those studies for PBR3. Nonetheless, the Commission viewed the studies as a useful point of reference and encouraged PEG to further refine its methodology, indicating that benchmarking evidence may inform stretch factor determinations in future PBR terms.[70]

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[67] British Columbia Utilities Commission. *Order G-69-25 and G-70-25.* March 18, 2025. p.47.

[68] Ibid. p.40-47.

[69] Alberta Utilities Commission.*2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities.* October 4, 2023. p. 43 and 83

[70] Ibid. 45

Hawaiian Electric Companies

Under Hawaiian Electric's PBR framework, the companies' revenue requirements are adjusted annually by an indexed formula. The X-Factor was set at zero percent. The customer dividend (stretch factor) consists of two components: a 0.22 percent annual compounding factor and a Savings Commitment tied to the companies' pledge to return $25 million in annual savings identified in a management audit. The 0.22 percent compounding factor was initially proposed by Hawaiian Electric as representing the average stretch factor in North American multi-year rate plans. The Commission noted that the customer dividend is fundamentally a policy judgment with no single correct methodology and adopted the 0.22 percent factor as a reasonable "down payment" on the efficiencies expected under PBR.[71] For the Savings Commitment, Order 37507 originally adopted a reduction in revenue requirement of approximately $22.16 million per year. However, in Order No. 37557, the Commission granted Hawaiian Electric's motion for reconsideration and approved an alternative of approximately $6.61 million per year (approximately 0.25%).[72]

Eversource (Massachusetts)

Under Eversource's PBR plan approved by The Department of Public Utilities ("DPU"), base distribution revenues are adjusted annually by a revenue-cap formula with an X-Factor of zero and inflation capped at five percent with a floor of zero. Capital-related revenue recovery is supplemented through a K-bar mechanism that provides incremental revenue based on a five-year rolling average of actual plant additions, subject to a spending constraint of ten percent above the company's forecasted capital budget.[73]

The consumer dividend (stretch factor) of 0.25 percent applies as a deduction to the PBR adjustment when inflation exceeds two percent. Eversource initially proposed a consumer dividend of 0.15 percent, supported by two cost benchmarking studies and the argument that continuation of an existing PBR plan warranted a lower consumer dividend than at the plan's outset. The Attorney General recommended at least 0.25 percent, contending that a longer benchmarking timeframe provided a more accurate comparison of the Company's cost performance against peers and that Eversource had not demonstrated specific, measurable efficiency improvements under its prior plan. In rebuttal, Eversource raised its proposal to 0.25 percent. The DPU accepted the revised proposal. The approved consumer dividend matches the level set in the Company's prior PBR plan.[74]

National Grid (Massachusetts)

National Grid's most recent PBR plan incorporates an index cap that is applied only to O&M-related revenues. Capital cost recovery during the rate plan is handled through a modified version of the company's proposed Infrastructure, Safety, Reliability, and Electrification mechanism, which allows the utility to update rates through annual filings to recover the revenue requirement on core investments placed into service in the prior calendar year, subject to

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[71] Hawaii Public Utilities Commission. *Docket No. 2018-0088. Decision and Order No. 37507.*
[72] Hawaii Public Utilities Commission. *Docket No. 2018-0088. Order No. 37557.* January 4, 2021.
[73] Massachusetts Department of Public Utilities. *D.P.U. 22-22. Order*. November 30, 2022. p. 64.
[74] Ibid. p. 26 and 59.

prudency review. Annual revenue requirement increases through this mechanism are capped at three percent of the company's total revenue.[75]

The consumer dividend (stretch factor) of 0.3% when inflation exceeds 2.75%, as proposed by National Grid, was based on the Department's historical findings on appropriate consumer dividends, claimed cost savings passed through to customers in base rates, and multiple benchmarking studies evaluating National Grid's cost performance from 2019 through 2022. The DPU increased the consumer dividend to 0.4%, applicable when inflation exceeds 2%, noting that the company is an average cost performer and had fallen short of the performance targets necessary for a reduction in its consumer dividend relative to the previous plan's dividend of 0.4%. Furthermore, the DPU observed that in prior PBR plans, the consumer dividend applied to the overall increase in base revenues, which included capital expenditures, and concluded that because the new PBR-O plan applies only to O&M expenses, a more aggressive consumer dividend was warranted to maintain sufficient customer benefits.[76]

Fitchburg Gas & Electric (Massachusetts)

Similar to Eversource’s approved plan, under the Fitchburg Gas & Electric PBR plan, base distribution revenues are adjusted annually by a total revenue-cap formula with an X-Factor of zero and inflation capped at five percent with a floor of zero. Electric capital-related revenue recovery is supplemented through a K-bar mechanism.

The consumer dividend (stretch factor) of 0.25 percent, applicable when inflation exceeds two percent, was set by the DPU over the company's proposal of zero percent. The company argued that setting the X-Factor to zero already created a large "implicit" consumer dividend of up to 1.95 percent (electric) and 1.30 percent (gas) relative to the empirical TFP results.[77] The DPU rejected this reasoning on several grounds: the DPU has never approved an explicit consumer dividend of zero; the Company's own benchmarking studies showed below-average cost performance; and the Company acknowledged that utilities implementing PBR for the first time – as Fitchburg Gas & Electric is – have greater potential for incremental performance gains than those already operating under such plans. The DPU also noted that Eversource had voluntarily proposed a 0.25 percent consumer dividend as part of its K-bar-oriented PBR framework and found the same level appropriate here given the similar PBR design approved for Eversource.

Eversource (New Hampshire)

The New Hampshire Public Utilities Commission (“NHPUC”) approved Eversource’s index-based rate plan, under which annual revenues are adjusted using an I-X formula with an X-factor of negative 1.42 percent and a stretch factor of 0.15 percent. Eversource had initially proposed an X-factor of zero, despite the results of its TFP study, and sought additional revenue through a supplemental capital adjustment known as the “K-Bar.” The NHPUC rejected the K-Bar mechanism and instead adopted a negative X-factor consistent with the findings of the TFP study.[78]

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[75] Massachusetts Department of Public Utilities. *D.P.U. 23-150. Order*. September 30, 2024. p. 19-56.
[76] Ibid. p. 87-90.
[77] Massachusetts Department of Public Utilities. *D.P.U. 23-80 and 23-81. Order*. June 28, 2024. p. 41.
[78] New Hampshire Public Utilities Commission. *DE 24-070. Order No. 28,170.* July 25, 2025. p. 2 and 52.

The stretch factor was proposed by Eversource and supported by its consultants. The proposed stretch factor was informed by precedent, as well as a benchmarking study that found Eversource Energy's costs are close to the electric industry's average costs.[79]

Great Britain Distribution Companies

Great Britain's electricity distribution companies currently operate under RIIO-ED2 (2023–2028), the second electricity distribution price control set under Ofgem's RIIO framework (Revenue = Incentives + Innovation + Outputs). Under RIIO-ED2, Ofgem sets a five-year total expenditure (totex) allowance for each distributor based on its own econometric benchmarking of efficient costs, which is then translated into annual allowed revenues through regulatory building blocks (return on capital, depreciation, tax, and in-year operating expenditure). Allowed revenues are further adjusted within the price control period through uncertainty mechanisms (volume drivers, re-openers, and cost pass-throughs) and output delivery incentives (analogous to PIMs). The framework also includes an "ongoing efficiency challenge" and a "catch-up efficiency challenge," which are broadly analogous to a productivity factor and stretch factor in other jurisdictions. The ongoing efficiency challenge was set at 1.0 percent per year for all distributors, while the catch-up efficiency challenge is company-specific, determined by the gap between a company's modelled efficiency and a frontier benchmark that glides from the 75th percentile in the first year to the 85th percentile by the fourth year of the price control.[80,81] The catch-up challenge efficiency benchmark is based on the weighted average results of multiple benchmarking analyses.

[79] New Hampshire Public Utilities Commission. *DE 24-070. Exhibit 9, Original Filing for Temporary and permanent Change in Distribution Rates Filed June 11, 2024. Attachment ES-AR-1*. June 11, 2024. p. 41.
[80] Ofgem. *RIIO-ED2 Final Determinations Core Methodology Document.* 30 November 2022.
[81] Ofgem. *RIIO-ED2 Final Determinations Overview document.* 30 November 2022.